Senate Rural Affairs and Transport References Committee

Questions on Notice – Tuesday, 9 August 2011
CANBERRA, ACT

Inquiry into management of the Murray-Darling Basin

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SENATE RURAL AFFAIRS AND TRANSPORT
REFERENCES COMMITTEE

Inquiry into the management of the Murray-Darling Basin

Public Hearing Tuesday, 9 August 2011

Questions Taken on Notice – NFF

1. HANSARD, PG 6

Senator WATERS: Coming back to the specific example where you say that crops were not able to be grown on pipes installed 50 years ago, they were presumably not coal seam gas pipes but this is an indication of what might occur with coal seam gas pipes in future. Is that correct?

Ms Kerr: It may be. We are certainly not experts in that area. It was an issue identified by a local farmer.

Senator WATERS: Would you be able to find out a little bit more information about that particular example because it goes to the question of whether coal seam gas permanently alienates the land, which is of relevance in Queensland where I am from. Our state government has made a determination that I disagree with. They claim that coal seam gas will not permanently alienate land because it will not sterilise the land for other uses for more than 50 years. The reference to 50 years made me think this could be an interesting example to demonstrate in just one way how in fact there is permanent alienation. Thank you for that.

National Farmers'
FEDERATION

25 August 2011

Jeanette Radcliffe
Committee Secretary
Senate Standing Committee on Rural
Affairs and Transport
PO Box 6100
Parliament House, Canberra ACT 2600

RECEIVED
29 AUG 2011
Senate Rural and Regional Affairs and Transport Committee

Dear Jeanette

Inquiry into the management of the Murray-Darling Basin: public hearing 9 August 2011

Regarding the specific question on notice, the National Farmers' Federation has been unable to make progress on ascertaining the reasons for landholders reporting cropping impacts several decades later.

It is possible that the decline in crop performance resulted from compaction of the soil, disturbance of soil processes, or degradation of organic matter and impacts on soil organisms. Alternatively, it may be that the process for digging the trench and backfilling it resulted in topsoil being buried under soil from lower horizons in the soil profile, i.e. the more fertile top few centimetres of soil was backfilled so that it is now underground.

A range of research exists around similar disturbance in forests, urban development and associated with roads, but not disturbance of agricultural land and in particular disturbance from digging trenches or the longer term establishment of road networks and other infrastructure on farms to service well sites.

In recent years, farmers have been actively moving towards practises that minimise the disturbance of soil. The implementation of low or zero tillage conservation farming is in part to improve soil health through reduced impacts to the soil structure and soil biota.

Yours sincerely

DEBORAH KERR
Manager – Natural Resource Management

SENATE RURAL AFFAIRS AND TRANSPORT
REFERENCES COMMITTEE

Inquiry into the management of the Murray-Darling Basin

Public Hearing Tuesday, 9 August 2011

Questions Taken on Notice – Santos

2. HANSARD, PG 16

Senator WATERS: There is a reference in your submission to the Worley Parsons report. I have only been able to find an executive summary of it. I would be really eager to see a copy of the full report. Are you able to supply it to the committee, please?

Mr Baulderstone: I am happy to supply the report.

SENATE RURAL AFFAIRS AND TRANSPORT REFERENCES COMMITTEE

Inquiry into the management of the Murray-Darling Basin

Public Hearing Tuesday, 9 August 2011

Questions Taken on Notice – QGC

3. HANSARD, PG 25

Ms Tanna: Thank you, Senator, and thank you also for your kind words. Yes, we incorporate all of the known emissions when we make these assessments, but, given the emotive nature of the debate, I do encourage all of us to look at independent assessments of life-cycle emissions and the relative benefits of natural gas as a transition fuel. I had the benefit of hearing the conversation between the committee and Santos earlier this morning on this topic. I heard them offer to send you the full WorleyParsons report, and there are other reports that can be made available. We would be pleased to follow up.

Senator WATERS: Thank you, I would be very pleased to receive those. That would be very helpful.

4. HANSARD, PG 25

Senator WATERS: Thank you, I would be very pleased to receive those. That would be very helpful. Roughly what proportion of your wells leak?

Ms Tanna: At this point, we have no known wells that are leaking.

Senator WATERS: What proportion of your pipes are leaking?

Ms Tanna: At this point, I am unaware that we have any pipes that are leaking.

Senator WATERS: When you say that you have no known leaks, how strict are your monitoring procedures to determine if they are any leaks?

Ms Tanna: We have a very extensive program of checking on the asset integrity in our operations. One thing that I would draw to the attention of the committee and commend to you as something for consideration is that the coal seam gas industry, while we have been in it for 12 years and I believe some of the other operators have been in it for quite a bit longer, has changed dramatically over the last three or four years in terms of the participation, with much more deeply experienced operators involved in the industry, bringing the best of international practice and the best, most deeply experienced professionals to work in the industry. The knowledge, expertise and ability to identify and address any issues have significantly increased over the past few years.

Senator WATERS: That is very good. I hope you do not mind me interrupting; I have a few more questions and time is short. Would you please table a bit more evidence about your extensive program of checking on the leaks. You could take that on notice and sent us some written material.

5. HANSARD, PG 27

CHAIR: I am starting to feel like I should just surrender to you all. Can you table for this committee the baseline assumptions upon which all of your information on the water is based? There have to be in any study baseline assumptions. Are you aware of them and could you table them?

Ms Tanna: The baseline information has been submitted through the environmental impact assessment process.

CHAIR: Could you table them for this committee?

Ms Tanna: The government has them.

CHAIR: I am asking you to table them to this committee.

Ms Tanna: We can certainly table our environmental impact assessment documents.

CHAIR: I want the baseline assumptions. I do not want all the garbage that goes around the wordsmithing of it. I just want the baseline assumptions. If you get that wrong, you get the whole thing wrong.

6. HANSARD, PG 27

Senator McKENZIE: What proportion of the revenues from your project will be paid in compensation to landowners?

Ms Tanna: I do not have that exact figure.

Senator McKENZIE: Could you table that for the committee please.

Ms Tanna: I do not think it is a relevant figure.

Senator McKENZIE: Whether you think it is relevant or not, the committee thinks it is a relevant figure. Therefore we would like it tabled.

Ms Tanna: We operate under a property rights system where the hydrocarbons are owned by the Crown. We do not own the hydrocarbons.

Senator McKENZIE: Sorry, I am asking what proportion it is. Santos was up-front and the figures, give or take X or Y, where all in their submission, which allowed us to calculate, rightly or wrongly, a percentage of their project's revenue that is being paid in compensation to farmers for access to their land. Given that information is not in your submission and you are unable to provide it to me verbally, could you please provide it to the committee in writing.

Ms Tanna: The more important conversation is how we approach access to the landowners—

CHAIR: We ask the questions. If the answer is no, just say, 'No, we are not prepared to do it.' It is either yes or no.

Ms Tanna: We can provide details of the compensation grouped in numbers.

24. Written Question on Notice, Senator McKenzie

You state in your submission that:

"QGC's view has also been confirmed by advice from Geoscience Australia and Dr M.A. Habermahl that "on the basis of available information, we consider that there is a limited likelihood of impact on the MDB groundwater or connected surface water resources as a result of any of the proposed operations." (p. 9)

The report also says that:

No data have been made available to examine the possible implications of hydrocarbons, eg, BTEX, in associated water.

> p.5
>
> *No proponents have considered the effect of faulting or fractures in their models.*
>
> p. 7
>
> *Analytical results for dissolved organic compounds (including BTEX) were not available for this report.*
>
> p. 37
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> *From the information available in the EIS documents it is not possible to separately assess drawdown of the alluvium water table resulting from direct connectivity with the Walloon Coal Measures and drawdown as a result of connectivity of the alluvial aquifer with other aquifers, in particular GAB aquifers.*

Can you explain why we are going ahead with these projects when there seems to be such a lack of information on key issues? Why hasn't this information been compiled before you went ahead with the final investment decision?

25. Written Question on Notice, Senator McKenzie

In the Geosciences and Habermahl report it also says on p. 37 that:

> *It can be clearly seen that the predicted drawdown varies considerably between aquifers and between proponent estimates. Interestingly, although QGC state that the conservative assumptions in their model would provide estimates of drawdown that are likely to represent maximum values, APLNG estimates for drawdown in the Springbok aquifer (for example) in a similar area are on the order of 3 times greater.*

Can you explain the differences between these estimates? Who is right? Why is there such large differences in the estimates of the impact of aquifers this late in the process?

3. HANSARD, PG 25

> **Ms Tanna:** Thank you, Senator, and thank you also for your kind words. Yes, we incorporate all of the known emissions when we make these assessments, but, given the emotive nature of the debate, I do encourage all of us to look at independent assessments of life-cycle emissions and the relative benefits of natural gas as a transition fuel. I had the benefit of hearing the conversation between the committee and Santos earlier this morning on this topic. I heard them offer to send you the full WorleyParsons report, and there are other reports that can be made available. We would be pleased to follow up.
>
> **Senator WATERS:** Thank you, I would be very pleased to receive those. That would be very helpful.

Please find below an annotated list of further independent reports that inform this debate and conclude that the climate impact of natural gas is consistently and significantly lower than that of coal. We have included copies of these.

> Australian Energy Regulator. 2009. *State of the Energy Market 2009*
> Attachment: AER_2009.pdf
>
> Department of Resources, Energy and Tourism. 2010. *A cleaner future for power stations – interdepartmental task group discussion paper.*
> Attachment: DRET_2010.pdf
>
> ACIL Tasman. 2008. *The impact of an ETS on the energy supply industry – Modelling the impacts of an emissions trading scheme on the NEM and SWIS.* Prepared for Energy Supply Association of Australia
> Attachment: ACIL_Tasman_2008.pdf
>
> Marano, J. J., Ciferno, J. P. 2001. *Life-Cycle Greenhouse-Gas Emissions Inventory For Fischer-Tropsch Fuels*. Prepared for U.S. Department of Energy National Energy Technology Laboratory by Energetics Incorporated, LLC.
> Attachment: Marano_Ciferno_2001.pdf
>
> Weisser, D. 2007. *A Guide to Life-Cycle Greenhouse Gas (GHG) Emissions From Electric Supply Technologies*, Energy 32, 1543.
> Attachment: Weisser_2007.pdf

All of these reports conclude that natural gas has a climate impact that is much lower than coal, which is an important aspect of a transition fuel strategy.

We assume that you are familiar with the letter by Howarth et al from Cornell University, as published in Climatic Change Letters, which claims that shale gas has potentially higher GHG emissions than coal when looking at whole of lifecycle emissions. Howarth et al use assumptions for their calculations that are not applicable in the Australian context. These are critiqued in the following commentary submitted to Climate Change by researchers also from Cornell University, and Electric Software Inc.

Cathles, L. M., Brown, L., Taam, M. and Hunter, A. 2011. *A Commentary on "The Greenhouse-gas footprint of natural gas in shale formations" by R.W. Howarth, R. Santoro, and Anthony Ingraffe.* Climate Change (submitted)
Attachment: Cathles_et_al_2011.pdf

The assumptions include leakage rates based on much older Russian pipelines and that gas reported as "unaccounted for" was vented, rather than used for electricity generation, captured, or flared.

The attached report by Elaine Prior from Citi also addresses these assumptions, and further provides a good analysis of the differences between shale gas and coal seam gas (also known as coalbed methane). This is in part a response to Howarth et al.

Prior, E. and Koenders, D. 2011. *Coal Seam Gas & Greenhouse Emissions, Comparing Life Cycle Emissions for CSG / LNG vs Coal*. Citi Investing
Attachment: Prior_2011.pdf

The key difference is in the release of methane during flow back of hydraulic fracturing fluid from shale gas wells due to the low permeability of shale compared to coal seams.

4. HANSARD, PG 25

Senator WATERS: Thank you, I would be very pleased to receive those. That would be very helpful. Roughly what proportion of your wells leak?

Ms Tanna: At this point, we have no known wells that are leaking.

Senator WATERS: What proportion of your pipes are leaking?

Ms Tanna: At this point, I am unaware that we have any pipes that are leaking.

Senator WATERS: When you say that you have no known leaks, how strict are your monitoring procedures to determine if they are any leaks?

Ms Tanna: We have a very extensive program of checking on the asset integrity in our operations. One thing that I would draw to the attention of the committee and commend to you as something for consideration is that the coal seam gas industry, while we have been in it for 12 years and I believe some of the other operators have been in it for quite a bit longer, has changed dramatically over the last three or four years in terms of the participation, with much more deeply experienced operators involved in the industry, bringing the best of international practice and the best, most deeply experienced professionals to work in the industry. The knowledge, expertise and ability to identify and address any issues have significantly increased over the past few years.

Senator WATERS: That is very good. I hope you do not mind me interrupting; I have a few more questions and time is short. Would you please table a bit more evidence about your extensive program of checking on the leaks. You could take that on notice and sent us some written material.

QGC takes seriously its obligations under the Petroleum & Gas Act with respect to detection and rectification of leaks at well sites and natural gas processing facilities. We fully comply with the Code of Practice for coal seam gas well head emissions detection and reporting, as issued by the Queensland Department of Employment, Economic Development and Innovation. Please see attached for a copy of the Code of Practice.

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> **CHAIR:** I am starting to feel like I should just surrender to you all. Can you table for this committee the baseline assumptions upon which all of your information on the water is based? There have to be in any study baseline assumptions. Are you aware of them and could you table them?
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A detailed description of the EIS hydro-geological model can be found in the QGC Environmental Impact Statement, Volume 3, Appendix 3.4, Appendix D. We have also attached a copy of this document.

The QGC hydro-geological model used to estimate the effect of gas production on neighbouring GAB aquifers for the QGC EIS was based on several assumptions:

- Water flow in the QGC project area was modelled
- The geologic strata from surface to basement were represented by 18 layers in the mathematical model, five of which represented the Walloons interval. These model layers varied in thickness and elevation as conditioned by available well and seismic data. Each layer had unique properties, and each layer was homogenous (rock properties varied between model layers but not within a model layer).
- Geologic faults were neither barriers nor conduits for flow, consistent with data.

Since the EIS submission, QGC has continued to update its hydro-geological model to reflect ongoing data gathering and analysis. QGC has used a second generation model to design its Water Monitoring and Management Plan, and is currently developing a third generation model that will represent water and gas flow. QGC, along with all other major industry participants, is cooperating with the construction of a regional water model being developed under the direction of the Queensland Water Commission.

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CHAIR: We ask the questions. If the answer is no, just say, 'No, we are not prepared to do it.' It is either yes or no.

Ms Tanna: We can provide details of the compensation grouped in numbers.

QGC’s compensation payments are determined by the value of the land, the use made of it and the impact of gas development.

Consistent with other industry participants, QGC expects its landholder compensation payments to represent less than 1% of total revenue for the QCLNG Project.

In addition to landholder compensation payments, other costs incurred by QGC include social impact payments, infrastructure investments, company tax, royalties, PRRT, carbon tax, capital expenses, operational expenses and finance costs.

QGC will spend more than $200 million on land access costs before the first revenues for QCLNG are received in 2014.

24. Written Question on Notice, Senator McKenzie

You state in your submission that:

"QGC's view has also been confirmed by advice from Geoscience Australia and Dr M.A. Habermahl that "on the basis of available information, we consider that there is a limited likelihood of impact on the MDB groundwater or connected surface water resources as a result of any of the proposed operations." (p. 9)

The report also says that:

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Analytical results for dissolved organic compounds (including BTEX) were not available for this report.

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From the information available in the EIS documents it is not possible to separately assess drawdown of the alluvium water table resulting from direct connectivity with the Walloon Coal Measures and drawdown as a result of connectivity of the alluvial aquifer with other aquifers, in particular GAB aquifers.

Can you explain why we are going ahead with these projects when there seems to be such a lack of information on key issues? Why hasn't this information been compiled before you went ahead with the final investment decision?

The questions reference several statements taken from "Assessment of impacts of proposed coal seam gas operations on surface and groundwater systems in the Murray-Darling Basin.", Moran and Vink, University of Queensland, 29 Nov 2010.

Regarding faults and fractures: QGC did not explicitly represent faults and fractures in its EIS hydro-geological model because QGC had no evidence of impact of such features on well performance. Subsequent data have not given any indication of faults connecting to adjoining aquifers.

Regarding analysis for BTEX components: QGC's previous and continuing analyses have not detected any BTEX in methane. QGC provide monitoring and reporting in accordance with the Queensland Government ban on BTEX from 2011.

Regarding assessing impact on the Condamine Alluvium and quantifying the direct impact of connection with the Walloons versus connection of the Condamine Alluvium with other GAB aquifers: the Condamine Alluvium is present only at the boundaries of the eastern-most QGC tenements, and is not in direct communication with the Walloons anywhere in the QGC project area. Any effect on the Condamine Alluvium due to QGC operations is therefore indirect as transmitted through intervening geologic strata. The QGC EIS modelling did not indicate any impact of QCLNG operations on the Condamine Alluvium.

25. Written Question on Notice, Senator McKenzie

In the Geosciences and Habermahl report it also says on p. 37 that:

> *It can be clearly seen that the predicted drawdown varies considerably between aquifers and between proponent estimates. Interestingly, although QGC state that the conservative assumptions in their model would provide estimates of drawdown that are likely to represent maximum values, APLNG estimates for drawdown in the Springbok aquifer (for example) in a similar area are on the order of 3 times greater.*

Can you explain the differences between these estimates? Who is right? Why is there such large differences in the estimates of the impact of aquifers this late in the process?

The question references a statement taken from "Assessment of impacts of proposed coal seam gas operations on surface and groundwater systems in the Murray-Darling Basin.", Moran and Vink, University of Queensland, 29 Nov 2010.

Regarding differences in the drawdown estimates made by the various project proponents: Moran and Vink continue their observations to list several factors that could contribute to such differences, including

- Differences in the spatial discretization of the models
- Differences in the data used for hydraulic properties
- Treatment of model boundary conditions
- Differences in the reference point for reporting drawdown

QGC acknowledges these, and specifically cites the first two points. Model construction is conditioned by the available data. The proponents' EIS groundwater models were based on different data sets, largely reflecting the data available within their project boundaries.

The Queensland Water Commission now has access to all of the data available from all of the CSG projects, and is working to produce a comprehensive regional ground water model. Interaction between the companies and the QWC over time will likely result in a convergence in views on regional hydrogeology.

Regarding ultimate estimate accuracy: The EIS estimates were made by capable companies with access to differing data sets concentrated on different parts of the Surat Basin. The range of estimates produced by these approximately contemporaneous analyses gives a reasonable feel for the certainty in the groundwater performance estimates.

List of Attachments

ACIL_Tasman_2008.pdf

ACIL Tasman. 2008. *The impact of an ETS on the energy supply industry – Modelling the impacts of an emissions trading scheme on the NEM and SWIS.* Prepared for Energy Supply Association of Australia

AER_2009.pdf

Australian Energy Regulator. 2009. *State of the Energy Market 2009*

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DEEDI_Code_of_Practice_2011.pdf

Department of Employment, Economic Development and Innovation. 2011. *Code of Practice for coal seam gas well head emissions detection and reporting.* Version 2

DRET_2010.pdf

Department of Resources, Energy and Tourism. 2010. *A cleaner future for power stations – interdepartmental task group discussion paper.*

Marano_Ciferno_2001.pdf

Marano, J. J., Ciferno, J. P. 2001. *Life-Cycle Greenhouse-Gas Emissions Inventory For Fischer-Tropsch Fuels*. Prepared for U.S. Department of Energy National Energy Technology Laboratory by Energetics Incorporated, LLC.

Prior_2011.pdf

Prior, E. and Koenders, D. 2011. *Coal Seam Gas & Greenhouse Emissions, Comparing Life Cycle Emissions for CSG / LNG vs Coal*. Citi Investing

QGC_2010-EIS_V3_A3.4.pdf

QGC a BG Group Business. 2010. *QCLNG Environmental Impact Statement.* Volume 3, Appendix 3.4, Appendix D.

Weisser_2007.pdf

Weisser, D. 2007. *A Guide to Life-Cycle Greenhouse Gas (GHG) Emissions From Electric Supply Technologies*, Energy 32, 1543.

The impact of an ETS on the energy supply industry

Modelling the impacts of an emissions trading scheme on the NEM and SWIS

Prepared for the
Energy Supply Association of Australia

23 July 2008

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Contents

Boxes, figures and tables

Executive summary

The study

This study has been carried out for the Energy Supply Association of Australia (esaa) to examine the effects of an Australian Emissions Trading Scheme (ETS) introduced from 2010 on Australia's stationary energy markets. Because a renewable energy target (RET), along the lines of the Commonwealth Government's proposed 20% by 2020 renewables target, affects the way energy markets respond to an ETS, the effects of both schemes on Australian electricity markets have been considered together.

The study covers Australia's two electricity markets, the National Electricity Market (NEM) and the Western Australian South West Interconnected System (SWIS), and the Australian gas market. The NEM and the SWIS include most wholesale electricity generation in Australia and if an ETS produces the required result in these two markets then it will work nationally for the electricity industry. Most of the gas market impact of an ETS occurs in eastern Australia, where gas demand for electricity generation is affected most, and the report tends to focus on effects in this market rather than the Western Australian gas market, where impacts are much less. The most profound changes occur in the NEM and most of the results presented in this report concern this market. The SWIS produces emissions savings in these simulations but its generation composition and pricing do not change as much as the NEM.

The work began by producing a simulation of the NEM and the SWIS in 2020 under current business as usual (BAU, with no ETS or RET) conditions using ACIL Tasman's simulation model of the NEM and SWIS, *PowerMark*. This model simulates the solution algorithm in these markets along with a routine that develops realistic revenue maximising bids as market conditions change and generators adapt to new circumstances. The model contains many other important parameters, including the marginal costs of generation at each power station, emissions intensity for each power station and the costs of generation for potential new entrants in each part of the market. Demand projections, in the form of hourly demand levels for each region, must also be developed and fed in to the model.

An ETS was then imposed on the 2020 simulation. This was done by adding an emissions cost to each power station's marginal cost according to their emissions intensity. The emissions price was increased until the target reduction in emissions was reached. When a power station could no longer cover its marginal costs (including emissions) and variable and fixed operation and maintenance costs from its pool revenue its generation was stopped and it was taken out of the market. Its generation was replaced by the lowest cost new entrant thermal generator or generation from renewable sources as a result of the RET.

The study does not assume any marked advances in generation technology or changes in costs and efficiencies. By 2020 we assume that carbon capture and storage is still in a demonstration phase, as is integrated gasification and combined cycle generation. We assume that the costs of a number of renewable technologies reduce, particularly photovoltaics (PVs) and we assume that geothermal generation based on hot dry rock resources is proven and commercial and the only factor slowing its take-up is the rate at which new plant and interconnection into the market can be built. Nuclear generation is not included as a generation option, although the costs of nuclear generation now being suggested would appear to make it a competitive alternative in 2020. We have assumed that, even if the Commonwealth Government was to agree to nuclear energy as a generation option, the lead time needed to put a licensing and approval process in place as well as the lead time for the plant itself would preclude it as an option in 2020.

In applying targets to the electricity markets we have also given consideration to the translation of broader economy-wide targets to electricity generation. Having looked at the likely response of other sectors, such as transport, direct combustion, fugitive emissions and agriculture, we have concluded that some, such as transport, are unlikely to meet their proportionate share of an economy-wide target at the emissions prices estimated in this study while others, such as forestry, are likely to produce a surplus of permits for sale to other sectors. The net surpluses do not appear to make up for the net deficiencies and it appears, on present indications, that electricity generation will need to meet at least its proportional share of any economy wide target.

The targets in the study are 10% and 20% reductions on 2000 emissions in the NEM and SWIS. When these targets were reached the emission permit prices were noted as were pool prices, retirement and new entry, gas and coal demand and likely retail prices. The project then turned to the effects of these changes in related markets. The increased demand for gas for electricity generation was fed in to ACIL Tasman's gas market model, *GasMark*, in order to estimate the effect on gas prices. Retail prices were fed into ACIL Tasman's general equilibrium model, Tasman Global, to provide an estimate of the effects on the total demand for electricity. We also looked at the way renewables generation might respond to the incentives of both a RET and an ETS and developed an estimate of renewables generation by type and state. The emissions permit prices reached appeared as if they would provide a significant incentive to forestry to increase plantings and offer more permits for sale and we also reviewed the potential in this market to increase output significantly and reduce the price of emissions permits.

These results were brought back to the *PowerMark* simulations of the NEM and the SWIS, which were re-run for each year between 2008 and 2020 using the new demand, gas prices and renewable generation developed in related market modelling. These last runs provided the final estimates of pool price paths, emissions permit price paths, retirements and new entry, renewable generation and emissions.

Findings

An emissions trading scheme could work

The simulations for both the 10% and 20% cases showed that an ETS could work as an instrument to achieve emissions reductions targets by 2020. They also showed that it would work in the way intended; more costly emission intensive plant would be retired first and the least cost substitute with lower emissions would take its place. This least cost replacement process would work as far as it is allowed, as higher cost substitutes in the form of renewable generation with support from the RET scheme would be promoted in some cases to levels of generation that would not arise if the market and the ETS alone were to determine the incentives for new entry.

While the simulations can help understand the effects on electricity prices and emissions, they do not capture the significant difficulties that would be encountered in terminating production from major assets well before the end of their technical life and terminating the employment that attaches to the plant and the mine.

In the simulations we also assume that replacement generators would take their place smoothly and there would be no disturbance in supply. Again in reality this may be different. The simulations indicate the forced retirement of about 6,700MW[1] of base load plant in the 10% case to be replaced by 15,000MW (including 1,200MW in the SWIS) of new plant between about 2011 and 2020. This is a rapid rate of replacement which has not been achieved in Australia before.

The actual emissions cuts being sought are more than the 2000 targets would indicate. Emissions in the NEM and the SWIS in 2000 are estimated at 165 million tonnes CO_2–e and by 2010, at the start of an ETS, they are estimated at 193 million tonnes CO_2–e. The 10% cut on 2000 reaches a level of 146 million

[1] The modelling results show that the closures are confined to the NEM only; the modelling suggests there would be no closures in the SWIS.

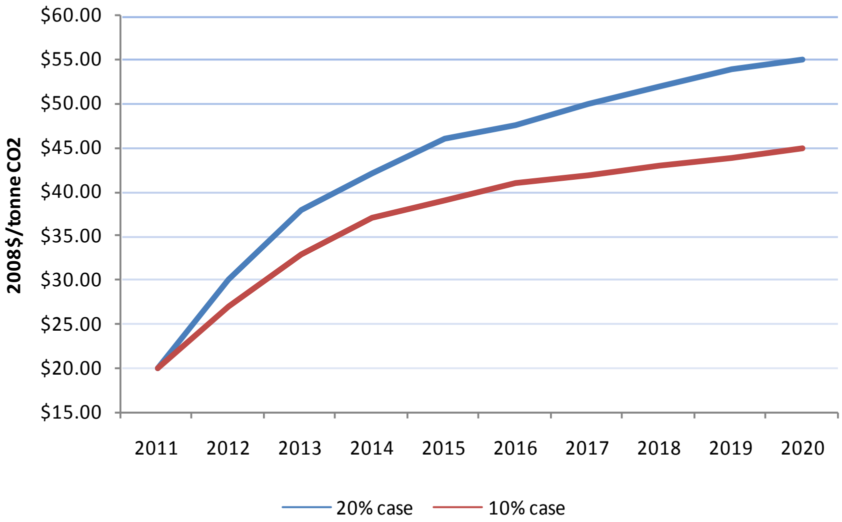
tonnes CO_2–e by 2020 (which is a 24% cut on 2010) and the 20% target reaches 127 million tonnes CO_2–e in 2020 (which is a 34% cut on the 2010 level).

Most of the impact of an ETS is felt in Victoria, where the simulations indicate that most of the brown coal plant would close. In the 10% case, 3 out of the 4 major brown coal generation plants in the Latrobe Valley close as well as all of the coal generation in South Australia. In the 20% case these plants close plus one major black coal plant in each of Queensland and NSW. In the main the generation from these plants is replaced by gas-fired combined cycle gas turbines (CCGTs) at high levels of energy conversion efficiency (in excess of 50%) and with about one third of the emissions intensity of brown coal generation and about one half of black coal. With assistance from the RET scheme renewable generation also replaces some of this brown coal plant. Geothermal energy is assumed to reach 1500MW of installed capacity by 2020 and wind generation also plays a significant role in Western Australia, South Australia, Victoria and NSW.

Emissions permit prices

The modelling produced an emission permit price of $45/tonne CO_2–e in the 10% case and $55/tonne CO_2–e in the 20% case (in 2008 prices). The emission price path calculated is shown in Figure 1. The price rises fairly steeply at first in order to achieve the necessary level of retirements and replacement and flattens somewhat as it gets toward 2020. The emissions price around 2020 is also likely to be influenced by the target for 2030. We have only included influences up to and including 2020 in this project.

Figure 1 **Modelled permit prices (2008$/tonne CO_2-e)**



Data source: ACIL Tasman modelling

Effects on electricity prices

Table 1 **Real and nominal electricity pool prices (NEM) and STEM prices (SWIS) ($/MWh)**

Nominal ($/MWh)	5 year average (2003 to 2007)	2020 (BAU)	2020 (10%)	2020 (20%)
NSW	$42.00	$71.20	$108.53	$116.84
Queensland	$33.65	$72.62	$109.07	$121.68
South Australia	$38.72	$79.05	$106.35	$110.40
Tasmania[1]	$45.97	$78.71	$97.62	$98.58
Victoria	$34.89	$68.94	$106.75	$112.67
WA (SWIS)[2]	$41.25	$45.08	$85.96	$92.91
Real (2008 $/MWh)				
NSW	$43.76	$51.65	$78.73	$84.76
Queensland	$35.03	$52.68	$79.12	$88.27
South Australia	$40.45	$57.34	$77.15	$80.09
Tasmania[1]	$46.42	$57.09	$70.82	$71.51
Victoria	$36.27	$50.01	$77.44	$81.73
WA (SWIS)[2]	$41.25	$33.52	$63.92	$69.08

Notes, 1, 2 year average
2, 1 year only
Data source: ACIL Tasman modelling

Table 1 shows the actual prices in the NEM and the SWIS up to 2007 and the modelled prices for 2020 under the three scenarios. The average prices up to 2007 provide a more reasonable basis for comparison as 2007 was not a typical year in most respects as the drought in eastern Australia affected prices significantly.

The SWIS prices shown in Table 1 represent prices from the Short Term Energy Market (STEM prices) in the in the WA Wholesale Electricity Market (WEM) only, and are thus not directly comparable to NEM pool prices. This is because, in the WEM, the STEM is only one component of market revenue available to generators. The WEM is comprised of two sub-markets: an energy trading market and a reserve capacity market. The majority of energy in the WEM is traded bilaterally, with the day-ahead STEM providing the market mechanism that facilitates trading around bilateral positions. The reserve capacity market is the mechanism whereby generators receive payment for provision of capacity, which can be a result of bilateral trades or the reserve capacity auction conducted by the IMO.

NEM pool prices in real terms are projected to increase by 93% in the 10% case and about 105% in the 20% case over average levels to 2007, reflecting the inclusion of the emission permit cost in generators' costs and the higher costs of generation.

In the SWIS, where prices increase by 55% and 67% in these two cases respectively, the price impact of an ETS is somewhat less than in the NEM. No major plant is retired in the SWIS, gas prices and to a lesser extent coal prices are already significantly higher than in eastern Australia and the price increases reflect the direct pass through of the emission permit price at the emission intensity of the coal fired plant. Emissions savings in the SWIS are made through the use of wind energy to meet growing demand and reductions in demand as a result of price increases.

Table 2 shows the indicative pass through of the increases in electricity costs through the ETS and the RET to retail tariffs. 2008 tariffs are representative of the allowance made by regulators for the components of retail costs in recent years in eastern Australia. Energy costs include pool and contracting costs and network costs include an allowance for both transmission and distribution.

Table 2 **Indicative pass through to retail tariffs, cents/kWh ($2008)**

	2008	2020		
		BAU	10% case	20% case
Cost of energy	5.8	7.3	9.4	9.9
Network costs	5.5	5.5	6.0	6.0
Retail margin	1.5	1.5	1.5	1.5
RET cost (20% by 2020 target)			0.9	0.9
Total	12.8	14.3	17.8	18.3

Data source: ACIL Tasman

Additional energy costs are incurred in the BAU as the higher real costs of gas and coal are passed through to electricity consumers in higher BAU pool prices. The higher energy costs in the 10% and 20% cases reflect the additions to pool prices between 2008 and 2020 in these cases and added to the allowance regulators currently make for energy purchasing costs. Network costs have also been increased slightly to allow for additional network investment that will be needed and finally an allowance for the RET cost retail consumers will be required to pay under the 20% RET has been included in the 10% and 20% cases.

Natural gas

The simulation modelling of the NEM indicates that gas demand for electricity generation will increase from 139PJ in 2008 to 375PJ in the 10% case and 508PJ in the 20% case. This marked increase in demand will have an effect on gas prices and ACIL Tasman's gas market model *GasMark* was used to provide an estimate of this effect.

The main anticipated source of future conventional gas discoveries is from the Bass Strait region of southern Australia. The contribution of coal seam gas (CSG) in Queensland and New South Wales is the other important component of the supply side assumptions.

One of the important demand side assumptions is that LNG production commences in central Queensland in 2014 at a rate of 4 million tonnes/year. The corresponding CSG requirement is assumed to be 220 PJ/a.

Overall, the consumption pattern in eastern Australia reflects strong growth until around 2020, but then begins to decline as supply side constraints and rising gas prices see under-satisfaction of the market. This has potentially significant implications for new gas-fired power generation facilities: the risk of gas supply shortfalls within the first decade after construction will need to be mitigated through measures such as long-term supply contracting.

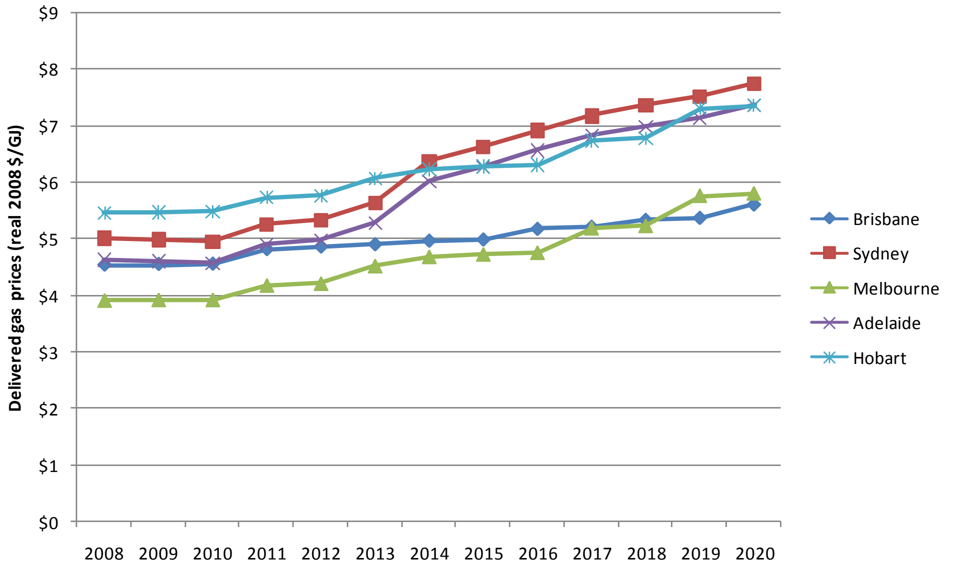
Victoria shows significant gas consumption growth, reflecting additional gas-fired generation introduced to replace brown coal plant. Queensland also shows strong consumption growth with further development of gas-fired generation located on or near CSG fields.

Figure 2 summarises the modelled wholesale gas prices (effectively the cost of gas for electricity generation) delivered to the city gate at each of the eastern state capitals. The necessity to access more costly production sources, together with increased price expectations as a result of the value uplift associated with emission trading and the exposure to international energy prices resulting from establishment of LNG production sees prices rising in real terms in all state capitals. The price rises are steeper in Sydney and Adelaide, where diversion of Queensland CSG production into LNG reduces availability for transfer to southern states. The price effects in NSW could be ameliorated if CSG production and associated infrastructure development proceeds more rapidly than has been assumed.

Victorian prices also rise strongly as a result of the decline in production from established fields in Bass Strait, and the greater reliance on new developments in deeper, more remote fields.

The modelling of the SWIS assumes a real long-run gas price of $6.50/GJ.

Figure 2 **Modelled wholesale gas prices**



Data source: ACIL Tasman *GasMark* modelling

Changes in generating plant

As expected, the three cases result in different changes to the supply schedule by 2020.

The tables below summarise the closures indicated by our modelling for the 10% and 20% cases post 2011[2]. In the 10% case 6,645MW of capacity is closed by 2020, compared with 10,425MW in the 20% case. Victoria contributes the vast majority of closures for the 10% case which is not surprising given the extent of brown coal fired capacity in that region. However, in the 20% case, the higher carbon prices result in an additional 3,800MW of closures from NSW and Queensland. The 20% case also results in some closures that occur in the 10% case being brought forward by one or two years due to the higher underlying carbon price. There are no projected plant closures in the SWIS in either the 10% or 20% cases.

When a plant is backed out from the market the demand for permits will fall by several million tonnes/year and the price is likely to be affected. Inter-temporal flexibility would assist in reducing permit price volatility between years.

Table 3 **Station closures aggregated by region, MW, 2011 – 2020**

Region	BAU	10% case	20% case
NSW	-	150	2,250
Queensland	-	890	2,570
South Australia	-	770	770
Victoria	-	4,835	4,835
Total MW by 2020	-	6,645	10,425

Data source: ACIL Tasman modelling

In the NEM, about 9,100MW of additional capacity is required between 2011 and 2020 in the BAU, compared with 13,700MW in the 10% case and 16,500MW in the 20% case. That is, the 10% and 20% cases require extra capacity compared to the BAU despite the lower load growth under an ETS. The extra capacity required is due to the closures of power stations and because some of the new entrant plant has lower capacity factors than the plant it replaces.

[2] Note that this analysis excludes closures that are common to all cases and which are not influenced by an ETS – for example, Swanbank B.

As shown in Table 4 the new investment in generation capacity between 2011 and 2020 amounts to about $13 billion in the BAU. The 10% case requires over $33 billion (including $3.1 billion in the SWIS) and the 20% case requires about $3 billion more investment than the 10% case to replace the additional power station closures.

Of these investments, $23.3 billion in the 10% and 20% cases is due to the 20% RET scheme (see Table 31). The expenditure on RET generation does not change under the 10 and 20% cases as the renewable generation target is assumed to be the same under both. The increase in investment between the 10 and 20% cases of $3.2 billion is all devoted to gas fired generation replacing coal fired plant which has been retired in the simulation. It is likely that some of the investment classified as renewable would take place without the RET scheme. This might include some if not all of the 1500MW of geothermal generation and some wind farms in coastal Victoria and South Australia.

These investment levels do not include the additional pipeline and transmission infrastructure required under the ETS to supply the additional generation from gas-fired plant and transportation of the energy from geothermal plant and wind farms to market. We estimate that this additional cost could amount to about $4.5 billion dollars ($500 million for new and upgraded gas transmission pipelines, $4 billion for electricity transmission).

Table 4 **Generation investment ($2008 million) aggregated by region, 2011 – 2020**

Region	BAU	10% case	20% case
NSW	$3,143	$6,033	$6,126
Queensland	$5,057	$6,929	$8,639
South Australia	$266	$5,220	$5,220
Victoria	$2,324	$12,118	$13,529
WA (SWIS)	$2,217	$3,105	$3,006
Total by 2020	$13,007	$33,405	$36,520

Data source: ACIL Tasman modelling

The cost of emissions savings

In these simulations plant exits the market when it cannot cover its short run marginal cost (including emissions costs) and its fixed operation and maintenance costs. Plant enters the market when it is the lowest cost new entrant (including its emissions costs) and the market can cover its long run marginal cost. Renewable energy generation is separately brought in to meet the expanded 20% renewable target in the 10% and 20% reduction scenarios.

It is clear that in all of these markets the lowest cost emission savings will come from energy conservation programs which educate and encourage consumers in low cost ways of saving energy. Building conservation programs also offer significant savings. It is very likely that most of these savings are at negative cost (that is they save emissions and deliver an expenditure saving).

Electricity demand response as a result of price increases will have some cost as a result of welfare losses consumers experience by not being able to consume something they would have had the price not been so high.

Sequestration (resulting in the supply of permits) from forestry, agriculture, overseas land management and re-forestation offers significant but as yet difficult to quantify savings. This is one of the uncertainties of an ETS discussed further below.

The study has taken account of energy conservation through Government programs and through consumers' demand response to higher prices. After these two responses have been considered the main process of saving emissions included in these simulations is substitution. In NSW and Queensland these new generators substitute for black coal fired generation and in Victoria brown coal fired. In South Australia they would have most likely been gas fired and in Tasmania also probably gas fired.

Where substitute generation is backing out or preventing entry by a brown coal plant, with the highest level of emissions intensity, the costs of savings are lower. In Victoria in 2010 the cost of each tonne of CO_2–e saved by using a gas fired CCGT was estimated at \$10, from wind \$45 and from solar thermal and PV over \$100/tonne CO_2–e. Table 5 shows the cost of savings through substitution at the beginning of the ETS and it is clear that the market is selecting the lowest cost savings substituting brown coal with gas fired generation in Victoria.

Table 5 **Cost of emissions saved by substitution, Victoria, NSW and Queensland in 2010 ($2008)**

	LRMC $/MWh	Emissions tonnes CO_2–e /MWh	Cost of emissions saved ($/tonne CO_2–e)
Victoria			
Coal fired plant (brown coal)	46	1.2	
Gas fired CCGT	54	0.4	10
Wind turbine	100	0	45
Solar thermal	200	0	128
Solar PV	240	0	162
NSW and Queensland			
Coal fired plant (black coal)	44	0.75	
Gas fired CCGT	60	0.40	46
Wind turbine	100	0	75
Solar thermal	200	0	208
Solar PV	240	0	261

Data source: ACIL Tasman modelling

Note: Victorian CCGT has lower LRMC due to lower gas price.

The estimated costs of emissions savings in Table 5 apply at the beginning of the ETS and indicate where the most efficient substitution savings lie. These costs will change over time as generation costs change (gas and coal costs increase), new zero emission technologies are introduced and the cost of alternatives such as geothermal, wind and solar falls and the major substitution options are used. While gas is the most efficient substitute early in the life of the ETS it is likely to be the fuel being substituted later in the life of the ETS (beyond 2020).

Table 6 shows the emissions and emissions intensity in the states included in this study. The modelled emissions shown in Table 6 are slightly less than those depicted in Figure 4 of the report as the model produced emissions reductions slightly greater than the 10% and 20% reductions targeted.

Table 6 **Projected emissions intensity and emissions by region**

	2000		2010		2020 BAU		2020 10% case		2020 20% case	
Region	tCO_2 /MWh	mt CO_2	tCO_2 /MWh	mt CO_2	t CO_2 /MWh	mt CO_2	t CO_2 /MWh	mt CO_2	t CO_2 /MWh	mt CO_2
NSW	0.85	55	0.82	64	0.77	73	0.74	60	0.65	50
Queensland	0.84	35	0.76	48	0.69	60	0.61	46	0.53	40
SA	0.78	8	0.68	7	0.67	8	0.16	2	0.16	2
Tasmania	0.02	0	0.03	0.3	0.04	0.5	0.03	0.3	0.03	0.3
Victoria	1.18	58	1.13	63	1.05	66	0.53	30	0.50	27
WA (SWIS)	0.70	10	0.64	11	0.69	14	0.51	9	0.50	8
TOTAL	0.92	166	0.83	193	0.77	222	0.58	146	0.52	127

Data source: ACIL Tasman modelling

Victoria shows a very large reduction in both emissions and emissions intensity as it goes through the biggest change in terms of the capacity of plant exit and new entry. South Australia shows the most striking reduction going from an emissions intensity of 0.78 tonnes CO_2-e/MWh in 2000 to a projected 0.16 tonnes CO_2-e /MWh in 2020 under both the 10% and 20% cases. This is because both of its coal fired power stations are assumed to be closed under an ETS and most of the new capacity in the state is either geothermal generation or wind turbines, both with zero emissions.

The SWIS shows a decrease in both emissions and emissions intensity because of the increased share of renewable generation and a smaller proportion of output from black coal.

Effects on asset values

As part of the simulations ACIL Tasman calculated the net return per kW of capacity for each power station, which involved taking each power station's revenue from the pool, subtracting fuel and material costs, emission permit costs as well as variable and fixed operation and maintenance costs. This parameter represents the amount left to pay capital after short run costs and overheads have been deducted but before tax and finance charges.

This parameter represents an indicator of the returns to capital in the alternative scenarios. A typical commercial approach to valuing an asset involves taking the present value of its estimated future net cash flows. In this case the only period over which cash flows can be aggregated and discounted is 2010 to 2020. Variations in asset value arising from changes in cash flows after 2020 are not included. The present value of net revenue per kW of capacity only provides an *indicator* of asset value as it does not take into account different approaches to financing, tax payments or deductions, the age of assets and future expenditures required for refurbishment. The indicator has also been calculated as an average for groups of similar assets and the effects on individual power stations can be quite different from the average. The difference in this indicator between the 3 scenarios provides a broad indication of the effect of an ETS on asset values over this period.

Using the net present value of returns per kW over the 10 years 2010 to 2020, the average of this indicator for Victorian and South Australian coal fired generation indicated a fall of over 80% in asset value in the 10% case and over 90% in the 20% case.

For NSW coal generation the corresponding falls were close to 80% and about 90% and Queensland coal fired generation assets also reduced by 80% and almost 95% respectively in the 2 ETS cases.

Gas fired CCGTs on average reduced in value by about 40% in the 10% case and about 45% in the 20% case, largely because of the increase in the costs of gas for generation. The average asset value of gas fired OCGTs reduced in value by 70% and about 80% respectively.

The only asset group to increase in value between the BAU and the ETS cases was hydro, and this was by 20% and 40% respectively. The comparison between the BAU and ETS cases was not possible for other zero emission technologies, such as geothermal and wind, as they were not included in the BAU case but it is highly likely that an ETS would increase the asset values in these technologies as well.

The major uncertainties

In a simulation and projection of this kind there are of course a number of major uncertainties in the assumptions. In fact one of the benefits of this type of modelling can be in identifying the major risks and possible opportunities in the future. Here we consider a number of the assumptions underlying the results that could vary and change the outlook significantly.

One of the major conclusions concerns the prices of permits under the two target scenarios ($45 and $55/tonne CO_2–e in the 10% and 20% cases respectively in 2008 prices). At these prices it is likely that a large volume of permits would be available from the Asian and South East Asian region based on forestry plantations, re-afforestation, prevention of land clearing and other agriculture. The actual volume that might be available is unclear at present and depends upon the responses in these countries. It also depends upon the willingness of the administrators of the Australian ETS to accept these permits and the ability to authenticate, monitor and audit them. The transaction costs are likely to be high but then again the potential benefits are also high.

Emissions are being reduced by 46 million tonnes CO_2–e in the 10% case and 65 million tonnes CO_2–e in the 20% case compared to 2010. It is possible that sequestration activities in the region could provide a high proportion of these, thereby lowering the permit price and reducing the plant closures and re-investment required to meet the targets.

We have also assumed that there are no major technological breakthroughs in the time to 2020 that would change the costs of generation in Australia. If technologies such as carbon capture and storage experienced major steps forward in proving their large scale operation at reasonable cost then this would also change the outlook considerably. Geothermal could also prove to be a breakthrough technology in Australia, where hot dry rock resources appear to be very good although remote. Given the number of interested explorers and developers it is possible this technology could develop at a faster pace than we have assumed in the study.

1 Introduction

The Energy Supply Association of Australia (esaa) has commissioned ACIL Tasman to assess the potential impacts of an emissions trading scheme (ETS) on the stationary energy sector in 2020. The Commonwealth Government has announced its intention to introduce an ETS by 2010 but at the time of completing this study the emissions reduction targets for 2020 have not been announced. The Government has committed to a target of 60% of 2000 emissions by 2050 however interim targets for years such as 2020 and 2030 have not been announced.

The project simulates the impact of both 10% and 20% reduction targets (on 2000 emission levels) to be achieved by 2020 in the NEM and the SWIS. The project has been carried out using ACIL Tasman's *PowerMark* simulation models of the National Electricity Market (NEM) and the WA South West Interconnected System (SWIS) along with *GasMark*, a model of the Australian gas market, and Tasman Global, a general equilibrium model of the Australian economy. *PowerMark* was used to estimate the price/tonne of CO_2–e needed to achieve the emissions targets. *PowerMark* includes the emissions coefficients for each power station which allows the cost of emissions to be added to the marginal costs of generation. This process increases costs in proportion to emissions and reduces generation from some power stations and eventually, when the emissions price is high enough, makes continued generation uneconomic in some cases. This process effectively backs out high emitters and replaces them with the lowest cost (including emissions cost) alternative.

The pricing of emissions in this way will also bring about changes in related fuel markets as well as the market for electricity. GasMark was used to estimate the effect of increased demand for electricity generation on gas prices and supply. Tasman Global was used to estimate the effect of increased electricity prices on demand in the future.

The Government's 20% renewables target will have a significant impact on the stationary energy market in the future and the effects of this needed to be included in the modelling.

The impact of these effects in different parts of the Australian economy was brought together to determine the overall impact on stationary energy markets. This report presents the methodology, assumptions and results of this analysis.

Chapter 2 sets out the methodology used to carry out the simulations. Chapter 3 presents the analysis undertaken within Tasman Global to estimate the level of demand reduction resulting from electricity price increases. Chapter 4 shows the assumptions made in this study on the contribution from renewable energy sources by both technology and regional location. In Chapter 5 we show the possible contribution to the sequestration task from forestry in Australia and discuss whether this might provide enough supply to reduce permit prices. Chapter 6 sets out the gas market assumptions and results showing gas supply and pricing. Chapter 7 describes the assumptions used in the electricity market modelling for both the NEM and the SWIS. In Chapter 8 the results of the electricity market simulations are presented along with other findings and conclusions on the overall impact of an ETS on the stationary energy sector.

1.1 The national emissions reduction task

The Government's climate change policy commitment is to cut GHG emissions in Australia by 60% of 2000 levels by 2050.

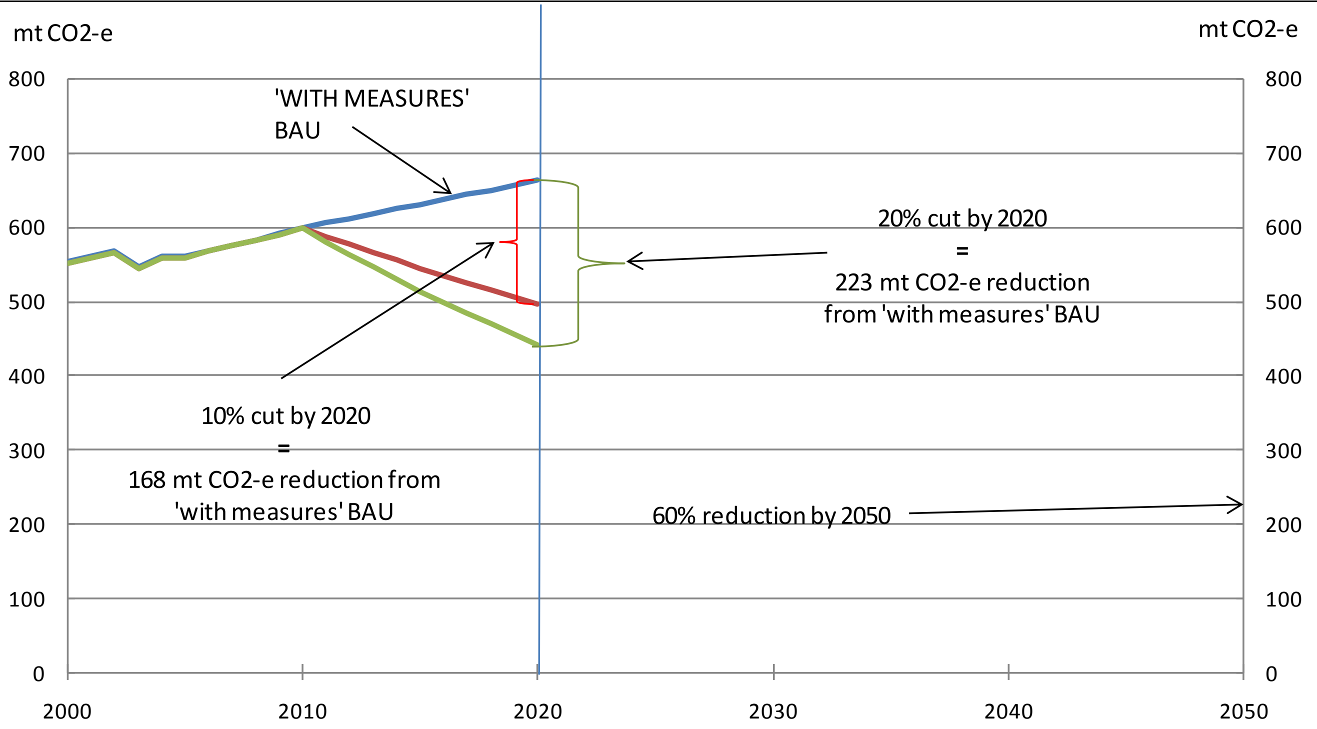
Based on information released by Climate Change Minister Penny Wong and the Department of Climate Change since the Federal election in November 2007 (up to May 2008), the proposed ETS is likely to have the following broad features:-

- The ETS will be a cap and trade system where emissions permits will be issued up to the level of an economy-wide cap and each year firms would surrender to the Government a number of permits equal to their emissions.
- The scheme will have relatively broad coverage, accounting for over 70% of our national emissions that can be practically covered.
- The scheme will be designed to enable international linkages.
- The scheme design will address the competitive challenges facing emissions-intensive trade-exposed industries in Australia.
- The scheme will also address the impact on strongly affected industries (Penny Wong, *Climate Change: A Responsibility Agenda*. Speech, 6 February 2008. p. 6-8.).

Figure 3 illustrates the emissions reduction task for the whole economy and covers the period 2000 to 2050. According to the Department of Climate Change, in 2000 the Australian economy emitted approximately 550 million tonnes of CO_2-e (DCC, 2008).

The 10% target requires a 168 million tonnes CO_2-e reduction in 2020 compared to the BAU case. The 20% target requires a reduction in emissions of 223 million tonnes CO_2-e in 2020 compared with the DCC BAU case.

Figure 3 **Economy-wide emissions reduction targets**



Data source: Department of Climate Change (2008), ACIL Tasman calculations

The DCC with measures case includes the effects of recently announced demand reduction programs including an expanded 20% by 2020 RET scheme, but not an ETS.

Table 7 presents the emissions reduction task information for the whole economy in a table. The last column in the table shows the emissions reduction task in the year 2020 for the 10% and 20% cases (168 and 223 million tonnes respectively).

Table 7 **Emissions reductions required in 2020: economy-wide**

Target reduction (from 2000 level)	Actual 2000 (mt CO_2-e)	Projected 2020 'with measures' BAU (mt CO_2-e)	Target 2020 (mt CO_2-e)	Reduction Task (relative to BAU) (mt CO_2-e)
10% (2020)	552	664	496	168
20% (2020)	552	664	441	223

Data source: DCC and ACIL Tasman calculations

1.2 Contribution of the energy supply sector to the emissions reduction task

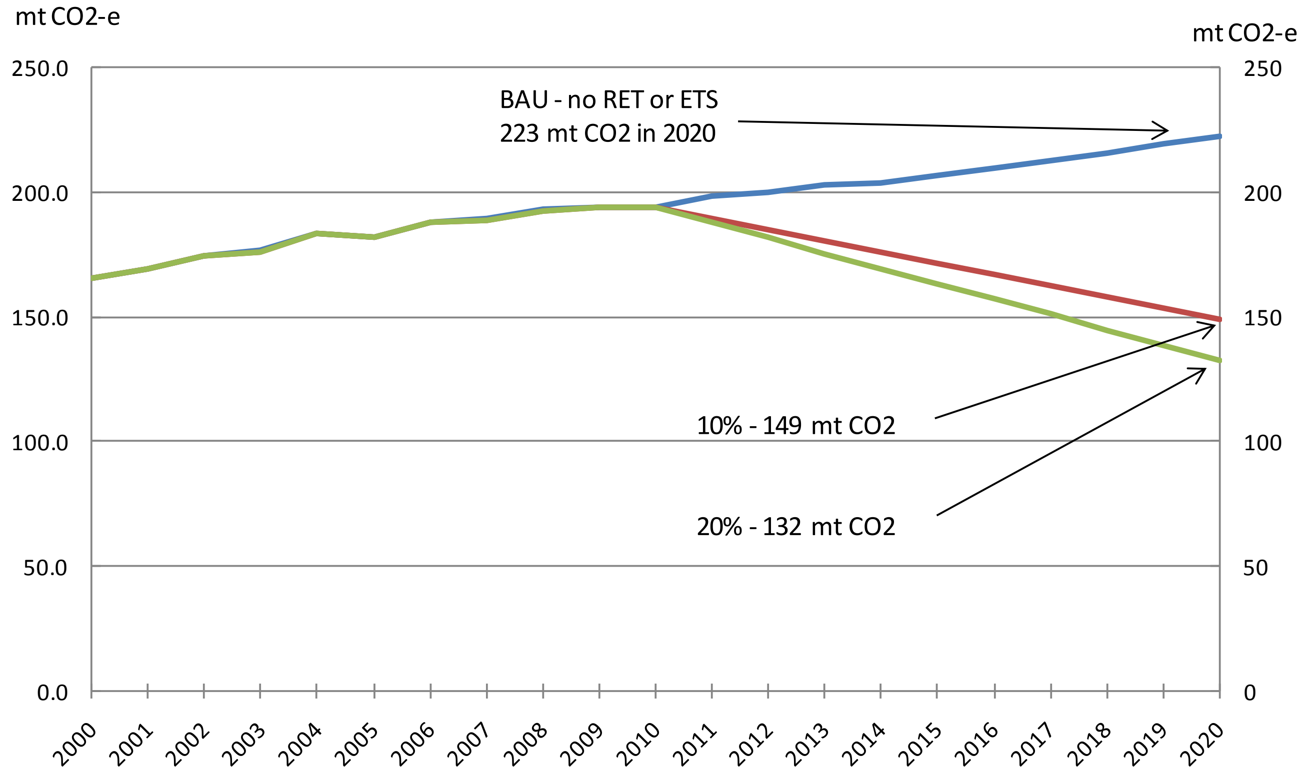
An ETS is intended to allow the economy to find the least-cost emissions abatement opportunities, regardless of which sector those opportunities come from, to minimize the overall cost to the economy of an ETS.

The stationary energy sector is responsible for around one-half of Australia's GHG emissions. The electricity generation sector produces around one-third of Australia's total GHG emissions — about 165 million tonnes CO_2-e in 2000 compared with 552 million tonnes economy-wide emissions in the same year (or 32%).

Figure 4 illustrates the emissions reduction task for the NEM and the SWIS, the electricity markets simulated in this project. The figure covers the period from 2000 up to 2020. The business as usual case (BAU) in this project is based on the 2007 NEMMCO SOO projection of demand in the NEM and the ERA projection of demand in the SWIS without the effects of a 20% by 2020 RET or an ETS. These demand projections include the effects of some existing government sponsored demand reduction and conservation schemes but not the effects of the two policy instruments (the 20% RET and ETS) which are under consideration in this study.

For the NEM and the SWIS combined, the 10% case requires a reduction in emissions of about 74 million tonnes CO_2-e compared to the projected 2020 BAU, (equivalent to a 33% reduction) and the 20% case requires a 90 million tonnes CO_2-e reduction (equivalent to about 40%) on the 2020 BAU projection.

Figure 4 **Projected emissions in the NEM and the SWIS, the 10% and 20% emissions targets compared to the BAU by 2020 (million tonnes CO_2–e)**



Data source: ACIL Tasman estimates of NEM and SWIS emissions

1.3 Contribution of the non-electricity sector to the emissions reduction task

Before analysing the effects of an ETS on the electricity sector alone, we have considered the question of whether a 10% economy wide target will result in a greater, lesser or similar target for stationary energy. Will other sectors contribute their proportional share to the savings target or is it likely to fall on one sector more than others. Another way of expressing this is whether a certain price on emissions will produce a higher or lower savings response from stationary energy than other sectors. Our review of recent literature on other sectors and our modelling of electricity markets in this project indicate that electricity generation will probably contribute more than its proportional share as a given price of emissions produces a bigger savings and substitution response from this sector than almost any other. A 10% economy wide target is likely to result in at least a 10% reduction from electricity generation and probably more.

For example, the Direct Combustion sector, which includes energy intensive industries such as petroleum refining, chemicals and non-metallic mineral products, emitted 76 million tonnes of CO_2-e in 2000. This is forecast to increase to 120 million tonnes CO_2-e in 2020. Hence, the reduction task facing this sector in 2020 is 52 million tonnes CO_2-e. The DCC forecast that the impact of the 'measures' targeted to this sector will be minimal reflecting the "diverse nature of the sector and the associated difficulties in targeting policies to reduce emissions, as well as measuring emissions and emissions abatement, from the sector" (DCC, 2008). DCC forecast the 'with measures' BAU case to be a saving of only 5 million tonnes of CO_2-e in 2020. For this sector, we have assumed that the impact of an ETS will be no more than twice the impact of current measures in place. In other words, we assume that the direct combustion sectors, with an ETS, will achieve a further 10 million tonnes CO_2-e reduction, significantly lower than the proportionate share reduction of 52 million tonnes CO_2-e.

In the case of the Forestry sector, we have considered the impacts of an ETS both on domestic forestry and the potential for international forestry offsets. We have attributed emissions abatement of a further 25 million tonnes CO_2-e/year in 2020 as a result of the ETS (see Chapter 6 below for a detailed discussion).

The scope for emissions abatement internationally could be very large and could possibly offset the Australian economy-wide task. However, we have assumed that the measurement problems and transaction costs from international offsets will limit the supply at least in the first decade or so of an ETS. For this project we have assumed that 10% of the Australian emissions abatement task will be allowed to be offset with international forestry credits — that is, we have assumed that international forestry will contribute 16.8 million tonnes of abatement to Australia's 168 million tonne reduction task (see Chapter 5 for a more detailed discussion).

Reviews of the transport sector have also generally concluded that the demand and substitution response from that sector for a given emissions price is likely to be less than that from stationary energy.

This high level analysis indicates that a 10% (or 20%) target economy wide is likely to mean at least that much for stationary energy, and possibly more.

2 Methodology

The approach has involved firstly estimating how certain national emissions reduction targets will be translated into targets for the NEM and the SWIS and then using simulation models of both markets to project the impacts of these targets. The impacts are estimated by introducing a price/tonne of CO_2-e emissions and increasing the short run marginal cost of each power station in the NEM and SWIS by their emissions cost. We simulate the process of an allowable cap on emissions by increasing the price of emissions permits, thereby lowering emissions until the target is reached.

The introduction of a price/unit for emissions from each power station will have other effects in these markets. An increased price for wholesale electricity will flow through to higher retail prices and demand will reduce in response to these higher tariffs. This reduction will take some time but it is clear that electricity demand is price responsive given a sufficient period for consumption to change.

Other impacts that need to be taken into account include the higher price for gas as a generation fuel in future (given a sharply increasing demand for it in eastern Australia) and an increase in coal prices given the high price of thermal coal on world markets.

Other important effects include the possible supply of emissions permits from areas such as forestry and agriculture in response to relatively high permit prices. This supply will have the effect of reducing the savings to be achieved from the stationary energy sector and reduce permit prices although, as discussed in the previous chapter, this does not appear to be a sufficient supply of permits to lower the target for stationary energy.

The steps followed, and the order in which the simulations were carried out, were as follows:

1. Convert the 10% and 20% emissions savings targets for the stationary energy sector into carbon prices for 2020 by running *PowerMark* NEM and SWIS market simulation models and finding the carbon price that produces the required savings.
2. Use the wholesale electricity prices developed in 1 to produce retail price estimates in 2020 for each sector and use the General Equilibrium model Tasman Global to estimate the effects on total demand and in different sectors for the two emissions scenarios.
3. Bring the carbon prices paths developed in 1 along with new entry costs for new technologies and the adjusted electricity demand projections back to the *PowerMark* electricity market simulation models of the NEM and SWIS to develop new prices, retirements and new entry investment.

4. Use the gas demand from the *PowerMark* 2020 runs to develop a projection of overall gas demand in WA and eastern Australia for electricity generation and use ACIL Tasman's gas market model *GasMark* to estimate prices for electricity generation and other uses in the WA and eastern Australian markets.
5. Use gas prices developed in 4 and the electricity market results from the *PowerMark* models of the NEM and SWIS to get a final estimate of electricity and gas prices, investment, retirements. Develop a feasible electricity change path between 2010 and 2020 and the emissions price path that can achieve this change.

An important part of the work is the ability to link ACIL Tasman's GE model (Tasman Global) with our electricity and gas market models (*PowerMark* and *GasMark*). More detailed descriptions of modelling methodology with the individual models are included in the chapters describing these particular parts of the project.

3 Estimating demand reductions resulting from price increases

ACIL Tasman's in house general equilibrium model of the Australian economy, Tasman Global, was used to estimate the demand side response to an increase in electricity prices resulting from a cut in electricity sector emissions of 10% and 20% below 2000 levels.

For this project, the Tasman Global modelling estimated a 12% reduction in demand by 2020 in the 10% emissions target case and a 14% reduction in demand in the 20% emissions reduction case compared to what would otherwise have been the case (i.e., a BAU case).

3.1 Tasman Global overview

Tasman Global is a multi-sector dynamic model of the Australian economy, covering Australia's six states, two territories and trade with foreign countries.

It models each Australian state and territory as an economy in its own right, with region-specific prices, consumers and industries. Since Tasman Global is dynamic, it is able to produce sequences of annual solutions linked by dynamic relationships.

Tasman Global is a model designed to simplify many of the complexities of the modern economy while at the same time capturing the important features of the system it represents. It provides a detailed, global economic system capturing important linkages such as:

- the direct linkages between industries and countries through purchases and sales of each others' goods and services; and
- the indirect linkages through mechanisms such as the collective competition for available factors of production that operate in an economy-wide and international context.

ACIL Tasman has given considerable attention to the representation of the energy sector in the model, particularly in relation to the interstate (trade in electricity and gas) and international linkages across the regions represented. To allow for more detailed and accurate energy sector analysis the underlying model database has been adjusted and extended to include relevant data from ACIL Tasman's *PowerMark* and *GasMark* models.

The most important aspect of this model integration is in the electricity sector, where the model employs a 'technology bundle' approach that separately identifies different electricity generation technologies (brown coal, black coal, oil, gas, hydro, nuclear[3] and other renewables).

3.2 Tasman Global modelling methodology

To model the impacts and demand side response to a cut in electricity sector emissions of 10% and 20% below 2000 levels, ACIL Tasman borrowed heavily from the methodology and assumptions used in previous similar work done for the then Australian Greenhouse Office (AGO) in 2007.

The work done for the AGO involved forecasting emissions in the stationary energy sector as well as the impacts on both energy and emissions of a range of current emissions reduction policies.

By using a similar methodology to previous work it allowed the Tasman Global modelling to focus on the task of estimating the demand side response to the emissions target rather than on the complex details of the 'business as usual' projection which is used to measure its impacts.

The methodology for the Tasman Global modelling proceeded in the following steps:

1. Create a reference case projection that represents the likely outcomes in the Australian economy in the absence of any, including current, emissions reduction policies.

2. Develop a 'business as usual' projection that represents the likely outcomes over the period to 2020 if all current emissions reduction policies are in place (not including the 20% RET). An important aspect of this step is the inclusion of a range of *PowerMark* BAU results about fuel shares, dispatch and prices. Also, the reference case includes a range of macro economic assumptions about GDP and GSP, labour supply and population growth. The business as usual model projection was built upon previous work done for the AGO and refined using current *PowerMark* modelling.

3. A third model projection was developed that includes all existing measures plus the emissions target of 10% below 2000 levels. This model run was referred to as the 'target scenario'. Under this scenario an emissions projection for the electricity sector is developed at a state level so that by 2020 national electricity emissions are close to 10% below their 2000 levels. For the Tasman

[3] Although Australia has no nuclear electricity, other regions in the model do.

Global modelling the 10% below 2000 target is about equal to a 20% cut in 2020 BAU electricity emissions. The emissions projection is then fed into model (made exogenous) whilst at the same time the model estimates a carbon tax in the electricity sector sufficient to achieve the desired emissions outcome. A final important aspect of the 'target scenario' is that for the Tasman Global industry 'non-ferrous metals' (mainly aluminium) an export subsidy was introduced that allowed this sector to maintain its BAU exports level despite the imposition of the carbon tax.

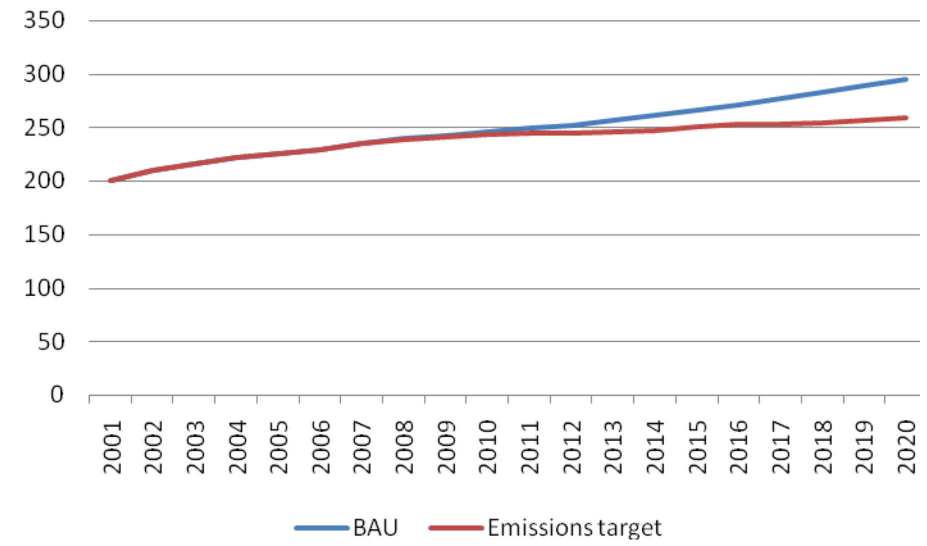
4. The demand side response is then estimated as the difference in electricity consumption between the BAU and the 'target scenario'. Also, a range of other outcomes can also be estimated such as the change electricity demand by industry type and households, or impacts on exports and GDP.

3.3 Tasman Global model results

The Tasman Global modelling indicates that a cut in electricity sector emissions of 10% below 2000 levels leads to a reduction in electricity demand of 12% in 2020 relative to the BAU. Or, a cut in electricity sector emissions of 20% below BAU levels in 2020 leads to a 14% decline in demand.

Over time, the decline in electricity demand increases in line with the emissions target. So, the decline in electricity demand ranges from a relatively small 0.6% below BAU in 2010 to 6% in 2015 through to 12% in 2020. Figure 5 shows the fall in electricity demand over time at a national level.

Figure 5 **Change in electricity demand, BAU and 10% case, TWh**



Data source: Tasman Global model results

For this modelling exercise the emissions permit price is introduced as a direct cost of carbon based inputs used in the electricity production sector. The direct initial impact of the emissions permit price is to increase the costs of production of electricity and an increase the price of electricity paid by households and industries.

The effects of the price increase were mitigated somewhat by assuming that prices did not increase to existing trade exposed energy intensive industries (TEEIs). This was intended to reflect the likelihood that the government will protect some existing TEEIs from increases in their electricity prices. At the time of undertaking this work we do not know which industries will be given offsetting payments or grants of permits to compensate them for the increase in their electricity prices. It is likely that any compensation will be less than 100% of the effective price increase. In this study we have assumed that currently producing aluminium smelters and other non-ferrous metal industries receive compensation to the point where their demand does not decrease. However, we have assumed that increased production of non ferrous metals in the form of smelter expansions or new smelters would not receive compensation through an emissions trading scheme. As a consequence, electricity consumption for non-ferrous metals in 2020 is lower in the 10% case than in the BAU case.

The fall in electricity demand across industries and households varies considerably. Table 8 shows the expected fall in electricity demand by industry sector and households for the 10% reduction case at 2020 relative to the BAU.

Table 8 **Per cent change in electricity demand by sector, 2020, 10% case and 20% case relative to the BAU**

Industry	10% case	20% case	BAU 2020 GWh
Primary agriculture	-8.10	-9.45	6,500
Fishery and forestry	-5.64	-6.58	166
Coal	-12.61	-14.71	6,795
Oil	-8.02	-9.36	687
Gas	-9.02	-10.52	629
Other minerals	-10.54	-12.30	8,739
Processed foods	-10.65	-12.43	7,927
Light manufactures	-12.52	-14.61	5,684
Petroleum products	-7.39	-8.62	2,508
Chemicals, rubber and plastics	-10.01	-11.68	8,456
Non metallic minerals products	-9.96	-11.62	6,308
Iron and steel	-13.88	-16.19	9,050
Non ferrous metals	-7.09	-8.27	52,008
Pulp, paper and publishing	-11.58	-13.51	7,818
Motor vehicles & transport equip	-13.35	-15.58	4,991
Electronics manufacturing	-15.91	-18.56	1,820
Other manufactures	-12.78	-14.91	3,874
Water	-12.49	-14.57	2,923
Construction	-6.60	-7.70	153
Wholesale and retail trade	-11.90	-13.88	23,668
Transport	-6.19	-7.22	6,293
Communications	-11.40	-13.30	1,730
Other business services	-12.27	-14.32	14,434
Other services	-11.72	-13.67	21,018
Households	-19.83	-23.14	73,557
Total	**-12.02**	**-14.01**	**277,736**

Data source: Tasman Global model results

Across the different industry types the general trend is that the more electricity intensive industries experience the greater decline in electricity demand since their costs and hence output prices will rise more than those industries that use relatively small amounts of electricity (apart from non-ferrous metals, discussed above). Households, with significantly more substitution possibilities and higher price elasticities, experience a greater fall in electricity demand.

In the 20% reduction case Tasman Global indicated a reduction of overall electricity demand compared to the BAU case of 14%. Again the existing non-ferrous metals sector was largely protected from this price increase but other sectors were subject to the commensurate retail price increases and the demand reductions recorded.

The reductions from both the 10% and 20% reduction cases were introduced into *PowerMark* as 12 and 14% reductions in both energy and annual peak demand.

4 Contribution of renewables

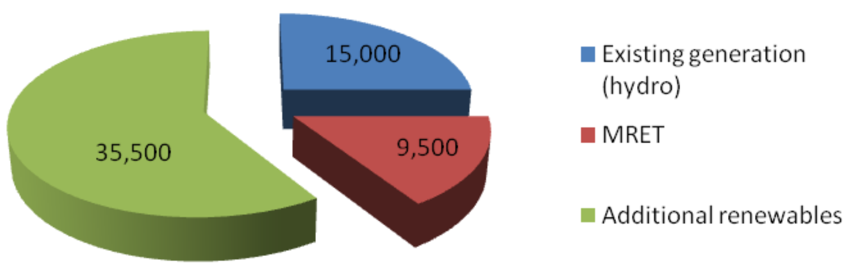
4.1 Introduction

The role of renewables in reducing carbon dioxide emissions in stationary energy has been increased by the announcement by the Commonwealth Government of a target of 20% of electricity generation from renewables by 2020.

This target has been implemented as 45,000 GWh of additional renewable energy by 2020, bringing the Mandatory Renewable Energy Target (MRET) to 60,000 GWh. The difference between the 60,000 GWh and 45,000 GWh of 15,000 GWh relates to the hydro generation existing before the introduction of MRET in 2001. This is mainly owned by Snowy Hydro and Hydro Tasmania.

After deducting the existing MRET of 9,500 GWh, there is an additional amount of 35,500 GWh of renewables required in the system. It is this 35,500 GWh that needs to be allocated across the regions in the NEM, Western Australia, Northern Territory and other regional areas for modelling the impact of an ETS. This is illustrated in Figure 6.

Figure 6 **Additional renewables from 20% target (GWh)**



The announcement of the new 20% by 2020 MRET has provided a clearer picture of the future role of renewables although some aspects of the interaction of the 2020 renewables target and the ETS are uncertain and have not yet been resolved. For example, the March 2008 discussion paper on an ETS from the Garnaut Review noted the following (Garnaut, March 2008).

> A second implication of the co-existence of the MRET with an ETS is that the former will affect the dynamics of the latter, with the potential for depressing the carbon price and thereby diminishing its capacity to drive both demand and supply change across the covered sectors. It will therefore be critical that these interactions are fully understood when the parameters of the ETS are being finalised.

4.2 State-based schemes

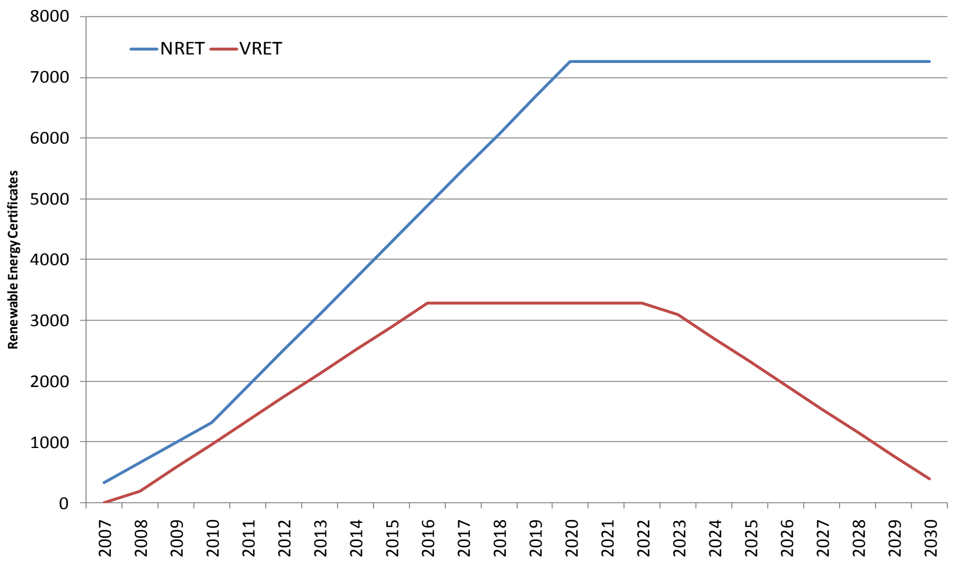
Over the past few years state governments have announced a number of renewable schemes similar to the MRET which require retailers to acquire renewable energy certificates to cover a certain proportion of their sales. These schemes are summarised as follows:

- VRET (Victoria)with a target of 10% by 2016 or an increase over the existing level of renewables of 3,274 GWh
- NRET (NSW) with a target of 10% by 2010 and 15% by 2020 or an increase over the existing level of renewables of 7,250 GWh
- SARET (South Australia) with a target of 20% by 2015
- WARET (Western Australia) with a target of 20% by 2020.

VRET has a penalty rate of $43/MWh which is indexed and requires renewables projects to be located in Victoria. NRET adopted similar provisions to VRET but allowed projects to be located outside NSW.

As depicted in Figure 7 the VRET continues to 2030 but tapers off from 2022 while the NRET scheme continues to 2030 at the rate of 7,250 GWh/year.

Figure 7 **VRET and NRET annual targets (GWh)**



We have assumed in this project that the Commonwealth Government's expanded MRET scheme will encompass the above state based schemes and that they will not be proceeded with in their current form. The states may want some of the features of their schemes retained but we expect such state based schemes will no longer exist once the newly expanded MRET scheme is commenced.

The MRET is currently scheduled to be terminated by 2020 but if some of the features of the state based schemes are adopted as a quid pro quo for rolling these schemes together then it is possible that the scheme could be extended to 2030. We have assumed this in our current study.

It is also unclear at this stage whether solar hot water systems will be included in the renewables target. Solar hot water was excluded from VRET on the basis that given there was a legislative basis for installing solar hot water systems (HWS) in new houses in Victoria, it was not necessary to offer an incentive in the form of RECs.

The combined scheme is being developed by the Ministerial Council on Energy (MCE) and will be announced in December 2008. In summary we have assumed the following combination of features in the Commonwealth scheme after the state schemes have been rolled in;

- the penalty rate will be $43 indexed
- the RECs will continue to 2030 but there will be a reduced number of RECs over the period from 2020 to 2030
- solar hot water systems will be excluded from the combined scheme.

4.3 Renewables and load forecasts

In the past renewable energy such as wind generation has been modelled in NEM simulation modelling as an effective reduction in demand. Wind generation is intermittent and its contribution has been estimated as an energy contribution that lowers overall energy demand and lowers peak demand to some extent. This reflects the way renewable generation has been introduced so far in Australia. Wind farms have not been scheduled generators in the NEM and they have not been required to offer their output into the market. In the future this is likely to change as wind farms will be required to be part of the national market and be scheduled along with other generators.

We have modelled renewable generation installed to date as non-scheduled distributed generation; effectively reducing energy demand. For most of the new generation that will be introduced under the expanded MRET scheme we have included such generation as scheduled generation in the NEM and the SWIS.

The 2007 Statement of Opportunities (SOO) load forecast from NEMMCO already incorporates deductions for some renewables and we have introduced additional renewables as scheduled generators.

4.3.1 Estimating wind generation in the NEM

For a proven renewable, such as wind generation, it is possible to determine:

- commissioned wind generation
- wind generation under construction
- wind generation publicly announced with planning approval, finance and power purchasing agreements (PPAs) in place
- wind generation publicly announced without planning approval, finance and PPAs in place.

There are a number of established companies such as Pacific Hydro, Roaring 40s and Babcock and Brown Wind Partners which provide details of the developments on their websites. There are also a range of overseas companies such as Acciona (Spain), Epuron (Germany) and RES (United Kingdom) that have planned developments in Australia. Finally, there are a range of other companies, usually Australian owned, that have proposed wind farms at various stages of development.

Established retailers such as AGL and Origin Energy have developed a range of joint arrangements with wind farm developers. This provides a means of meeting their commitments as retailers under MRET and makes it easier to offer GreenPower products to consumers.

In making estimates of wind farm generation we have taken a conservative view on the timing of new developments. The time required for planning approvals, especially if approval is required by state governments, compared with local government can be several years. Some wind farm developments require Commonwealth Government approval.

4.3.2 Transmission

The Garnaut Review has drawn attention to the cost of transmission for renewables projects (Garnaut, March 2008).

> A significant uptake in intermittent sources such as wind or solar may require complementary storage or back-up capacity. More remote supply, such as wind and geothermal, will generate a need to review the mechanisms that trigger the construction or upgrading of transmission lines.

Transmission is likely to be an issue for a number of new renewable sources such as wind, geothermal and perhaps solar generation. New generators connecting to the NEM are currently required to build or pay for their connection to the nearest node on the system. The transmission system in each of the Australian states has developed as a radial system, connecting the major load centres with major generation centres, usually situated on major coal basins, and getting thinner and thinner as the network radiates out to more remote areas.

The current regulatory test for including transmission investment may make it difficult to connect some of these remote new generators into the market. In this study we have assumed that wind generation is connected to the market as necessary and that geothermal generation enters the market in both South Australia and Queensland through new transmission lines. Other factors, such as the technical limits on intermittent generation in relatively small regions like South Australia have limited the capacity of wind generation assumed in certain regions.

4.3.3 Wind generation forecasts

In developing wind generation forecasts, all known publicly announced developments were considered. A conservative view has been taken in terms of the timing of projects.

An estimate has then been made of future wind generation projects based on the additional generation projected for the years to 2010, 2011 or 2012. In making these projections, an allowance has been made for a backlog of projects that were delayed until VRET and NRET were introduced. Therefore, the projects grow at a lower rate after 2012.

The projected level of wind generation is conservative for South Australia. When all planned wind farms were incorporated into the projections the increase in renewables had a severe effect on the pool price in South Australia. Therefore, we have scaled back the level of renewables from wind in South Australia.

An average capacity factor of 30% has been assumed for wind capacity. In some cases it is likely to be above this but as more sites are used it is also possible that new sites will average below 30%.

The wind generation in Table 9 and Table 10 is additional wind generation that has not already been included in the 2007 SOO. For example, in Victoria, the 2007 SOO includes 250 MW for Waubra and Portland and 854 MW for advanced projects by 2009-10. Therefore, there is no additional generation included in Table 9 and Table 10 for Victoria until 2011.

Table 9 **Assumed additional wind generation capacity (MW) – 10% and 20% cases**

	NSW	Vic	SA	Tas	WA	Total
2008	0	0	0	0		0
2009	151	0	255	140	191	737
2010	181	0	506	140	191	1018
2011	318	139	609	140	241	1447
2012	667	529	609	140	341	2286
2013	967	879	609	140	391	2986
2014	1,267	1,229	609	140	491	3736
2015	1,567	1,579	609	140	541	4436
2016	1,727	1,779	609	140	591	4846
2017	1,855	1,939	609	140	641	5184
2018	1,957	2,067	609	140	691	5464
2019	2,039	2,169	609	140	741	5698
2020	2,105	2,251	609	140	791	5896

Note: Does not include wind generation in 2007 SOO load forecasts

Data source: ACIL Tasman estimates

Table 10 **Assumed additional wind generation (GWh) – 10% and 20% cases**

	NSW	Vic	SA	Tas	WA	Total
2008	0	0	0	0		0
2009	394	0	675	368	668	2,105
2010	473	0	1,332	368	668	2,840
2011	832	368	1,603	368	843	4,014
2012	1,752	1,393	1,603	368	1,194	6,310
2013	2,540	2,313	1,603	368	1,369	8,193
2014	3,329	3,232	1,603	368	1,719	10,251
2015	4,117	4,152	1,603	368	1,895	12,135
2016	4,538	4,678	1,603	368	2,070	13,257
2017	4,879	5,098	1,603	368	2,245	14,194
2018	5,142	5,431	1,603	368	2,420	14,964
2019	5,361	5,703	1,603	368	2,595	15,630
2020	5,528	5,913	1,603	368	2,772	16,184

Note: Does not include wind generation in 2007 SOO load forecasts

Data source: ACIL Tasman estimates

4.4 Projections for geothermal generation

In the geothermal exploration and development industry at present there are 33 companies with 277 licences and projected work programs of $851 million (Geodynamics, January 2008). While both current levels of activity and expectations are high, the industry has not yet demonstrated the hot dry rock technology on a commercial scale. Recent developments in tests by Geodynamics have supported expectations rather than dampening them. However, the development of a new generation technology is likely to come across problems and a schedule for new generation from this source is difficult.

We have assumed that by 2020 there is 1,500MW of geothermal capacity operating on the Cooper Basin in South Australia and that 750MW of this enter the network through a transmission line to South Australia and the other 750MW enter through an even longer line to Queensland. We have not made any assumptions about who might install and pay for these interconnectors (we do not need to make this assumption in order to include the capacity in the simulation modelling) and whether they are regulated or unregulated interconnectors.

We have assumed that geothermal capacity has a capacity factor of 85%. Projected capacity and generation is shown in Table 11 and Table 12 respectively.

Table 11 **Assumed geothermal capacity by region (MW) – 10% and 20% cases**

	NSW	Vic	SA	Qld	WA	Total
2014	0	0	60	0	0	60
2015	0	0	120	0	0	120
2016	0	0	500	0	0	500
2017	0	0	750	0	0	750
2018	0	0	750	250	0	1,000
2019	0	0	750	500	0	1,250
2020	0	0	750	750	0	1,500

Data source: ACIL Tasman estimates

Table 12 **Assumed geothermal generation by region (GWh) – 10% and 20% cases**

	NSW	Vic	SA	Qld	WA	Total
2014	-	-	399	0	0	399
2015	-	-	797	0	0	797
2016	-	-	3,321	0	0	3,321
2017	-	-	4,986	0	0	4,986
2018	-	-	4,986	1,671	0	6,657
2019	-	-	4,986	2,679	0	7,665
2020	-	-	4,986	5027	0	10,013

Data source: ACIL Tasman estimates

4.5 Projections for solar generation

The Solar Cities project with funding of $75 million has provided incentives for solar generation. It is expected that additional projects will develop from the Solar Cities work. The estimates of solar generation are restricted to concentrated solar projects that can be identified. Estimates of distributed solar PV for residential or commercial use are handled by making reductions in projected loads.

The largest planned concentrated project is the Solar Systems Project in North East Victoria. This project has funding from the Australian Government of $75 million, Victorian Government of $50 million and finance from TRUenergy. This is planned as 150 MW, which can be translated to some 315 GWh at a capacity factor of 24%. A demonstration plant is currently under construction in Central Victoria as part of the Solar Cities Project.

In addition to this project which is planned for construction between 2010 to 2015, solar PV is projected as increasing by 80 MW/annum from 2011 for the NEM. This additional solar PV is assumed to be split equally between NSW, Queensland, South Australia and Victoria. Using a capacity factor of 24%, the solar PV generation used for *PowerMark* modelling is shown in Table 13.

Table 13 **Assumed additional concentrated solar by region (GWh) – 10% and 20% cases**

	NSW	Vic	SA	Qld	WA	Total
2008						
2009					0	0
2010		66			0	66
2011	44	192	44	44	84	407
2012	82	318	82	82	84	648
2013	126	443	126	126	84	905
2014	170	482	170	170	84	1,075
2015	208	526	208	208	168	1,318
2016	252	569	252	252	168	1,493
2017	296	608	296	296	168	1,663
2018	334	652	334	334	168	1,822
2019	378	695	378	378	168	1,997
2020	422	734	422	422	336	2,335

Data source: ACIL Tasman estimates

4.6 Projecting generation from biomass

Biomass is the term used to describe the generation of energy from organically based energy sources. Current biomass generators include landfill gas, sewage gas and bagasse (sugar cane waste).

In recent years the number of RECs for biomass from the MRET program has failed to grow at the rate of earlier years.

Based on this information and a search for information on biomass projects, the following estimates have been made for **additional** biomass generation. Projects that are included in the MRET of 9,500 GWh are not included. These projects will have already been subtracted from the 2007 SOO load forecasts.

Table 14 **Assumed additional biomass by region (GWh) – 10% and 20% cases**

Year	NSW	Vic	SA	Qld	WA	Total
2008	61	44	18	79		201
2009	123	79	44	158	350	753
2010	184	123	61	237	350	955
2011	237	158	79	324	788	1,586
2012	298	201	96	403	788	1,787
2013	359	237	123	482	788	1,989
2014	420	280	140	561	788	2,190
2015	482	324	158	639	1,226	2,829
2016	543	359	184	718	1,226	3,031
2017	596	403	201	797	1,226	3,224
2018	657	438	219	876	1,226	3,416
2019	718	482	237	964	1,226	3,627
2020	780	517	263	1,042	1,226	3,828

Data source: ACIL Tasman estimates

4.7 Projections of total renewables

By 2020 the projections for total renewables for the NEM and SWIS are 32,360 GWh as detailed in Table 15. This is slightly short of the targeted 35,500GWh, and the shortfall is immaterial to the study and is a result of the conservative assumption regarding the amount of wind farm capacity in South Australia.

Table 15 **Electricity generation by type of renewable (GWh)**

Year	Wind	Geothermal	Solar PV	Biomass	Total
2008	0	-		201	201
2009	2,105	-	0	753	2,858
2010	2,840	-	66	955	3,861
2011	4,014	-	407	1,586	6,007
2012	6,310	-	648	1,787	8,745
2013	8,193	-	905	1,989	11,087
2014	10,251	399	1,075	2,190	13,915
2015	12,135	797	1,318	2,829	17,079
2016	13,257	3,321	1,493	3,031	21,102
2017	14,194	4,986	1,663	3,224	24,067
2018	14,964	6,657	1,822	3,416	20,202
2019	15,630	7,665	1,997	3,627	28,919
2020	16,184	10,013	2,335	3,828	32,360

Data source: ACIL Tasman estimates

5 Forestry

5.1 Introduction

In this chapter we look at the potential contribution of forestry to the supply of permits in Australia over the period to 2020. Given the prices of permits needed in the 10% and 20% reduction cases it is likely that there will be a supply side response and such prices will provide an incentive to sequestration activities such as forestry. If this supply is large enough it could well lower the price of permits and reduce the impacts on the stationary energy sector.

Our analysis of recent work by DCC and Tree Plantations Australia (TPA) and the National Association of Forest Industries (NAFI) suggests that domestic forestry could contribute about 25 million tonnes of *additional* emissions abatement at around a \$40 to \$50/tonne of CO_2-e in 2020 (at 2008 prices).

5.2 The potential for forestry

There are three main sources of carbon sequestration in forestry:

- new tree planting or *afforestation*;
- replacement tree planting or *reforestation*; and
- avoided tree removal or *avoided deforestation*.

Forestry sequestration (avoiding deforestation, reforestation and afforestation) is well known and readily quantifiable and is the only agricultural enterprise likely to meet the offset standards in the initial stages of an ETS.

According to NAFI and TPA the Australian forest estate is 164 million ha—covering 21% of the continent (NAFI and TPA, 2007). This is broken into 162.7 million ha of native forests and 1.8 million ha of plantation forests. The total amount of carbon stored in Australia's forests in 10.5 billion tonnes, which is equivalent to 70 times Australia's annual emissions.

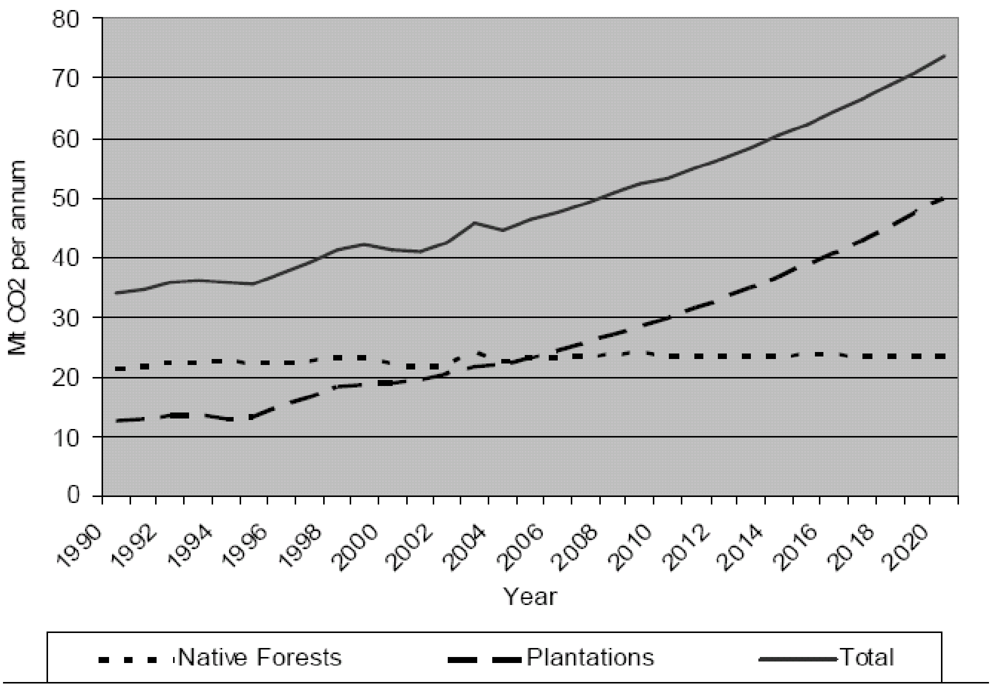
According to NAFI and TPA, production forests, which include commercial native and plantations, in 2004 removed a net 44 million tonnes of CO_2-e from the atmosphere, split evenly between the forestry types.

Commercial native forest sequestration is set to remain relatively constant, at around 23 million tonnes of CO_2-e/annum. Plantation expansion on the other hand has seen annual sequestration nearly double from 12.7 million tonnes in 1990 to 23 million tonnes of CO_2-e in 2005.

NAFI and TPA claim that recent tax certainty for plantation forestry, including the facilitation of a secondary market to encourage greater investment in long rotations, mean that there is the potential to establish 75,000 ha of new plantation each year until 2020.

Figure 8 below illustrates the potential cumulative increase in annual carbon sequestration rates from roughly 50 million tonnes in 2010 to about 75 million tonnes in 2020, or (by 2020) 25 million tonnes/year.

Figure 8 **The potential net atmospheric removal of CO_2-e by Australia's production forests**



Data source: (NAFI and TPA, 2007)

We draw a similar conclusion for the potential for carbon sequestration in Australian forestry using the results of the global supply curve modelling that appear in Sohngen, Sedjo, and Mendelsohn, (2001). Table 16 illustrates a number of modelled scenarios based on alternative prices for carbon under an ETS. For example, this means that under scenario 3, (which is the closest to our 10% emissions reduction carbon price of $45), the average annual *additional* CO_2-e accumulation would be around 2.5 million tonnes/year. And since new forest plantations will continue to sequester carbon, by 2020, an additional 25 million tonnes of carbon will be sequestered at a $50 carbon price/year.

Table 16 **Possible Australia CO_2-e m/t response to various price scenarios as used in global supply curve study**

	$5.00/t rising by 2.5% pa	$20.00/t rising by 2.5% pa	$50.00/t rising by 2.5% pa	$100/t pa flat
2010	3.69	13.16	25.68	29.47
2020	6.31	24.29	52.54	52.54

Based on the potential for additional sequestration suggested by NAFI and TPA and from the indicative results shown in Table 16 we have made an estimate of sequestration offsets available from forestry of an *additional* 25 million tonnes of CO_2-e by 2020 under an ETS.

This project is centred on the effects of an ETS on the stationary energy sector and forestry has not been the main object of our attention. However, we believe that the outlook for forestry needs to be considered as it has the potential to supply large quantities of offsetting permits, thereby lowering permit prices and changing the impact on stationary energy.

Given the limited potential for other sectors such as transport and direct combustion to reduce their emissions significantly at the permit prices estimated in this study, the supply of permits from forestry is likely to be needed to help meet a 10% or 20% reduction target but it is unlikely to reduce the reduction in emissions required from stationary energy. A 10% Australian reduction is still likely to require at least a 10% reduction from stationary energy. The same applies to a 20% reduction.

6 Gas supply, demand and pricing

Assumptions regarding the availability and pricing of natural gas represent key inputs to the electricity market modelling. In this analysis, we have estimated future gas prices for power generation in the NEM states using ACIL Tasman's gas market model *GasMark*. There is a degree of circularity in this process, since the demand-side assumptions about the quantity of gas likely to be required for power generation with an ETS are an input to the gas market modelling, but are inherently dependent on the price at which gas will be available to generators. To deal with this issue, gas for electricity generation assumptions was initially derived from a preliminary *PowerMark* run prepared using estimated gas prices. *GasMark* was then set up using these gas demand results. The model was rerun and the derived prices passed back to *PowerMark* for the final electricity model runs.

6.1 Gas market assumptions

The gas market outlook incorporates what ACIL Tasman considers to be reasonable mid-line assumptions that reflect current thinking on gas supply and demand in Eastern Australia.

6.1.1 Supply assumptions

It has been assumed that future gas supply will be drawn from:

- existing conventional gas fields, based on current production capacity and known reserves
- new conventional gas discoveries based on a reasonable assessment of discovery rates and output profiles when brought into production
- existing and future coal seam gas (CSG) developments in Queensland and New South Wales.

The main anticipated source of future conventional gas discoveries is from the Bass Strait region of southern Australia. The assumptions in relation to Bass Strait production and resource backing for existing fields reflect installed production capacity and known gas reserves (proven & probable, "2P").

Table 17 summarises the reserves, production rate and minimum ex-field price assumptions for existing fields and new discoveries in Bass Strait. Light shading denotes resources discovered but yet to be developed; darker shading denotes resources yet to be discovered.

Table 17 **Bass Strait reserves, production and price assumptions**

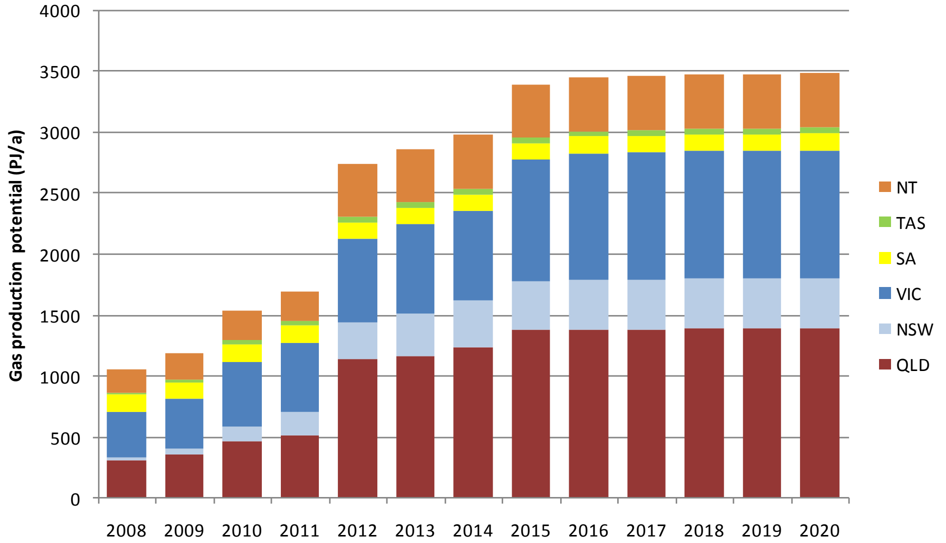
	Reserves (PJ)	Production capacity (PJ/a)	Min Price ($/GJ)
Otway Basin			
Minerva	375	40	$3.10
Geographe	800	30	$3.35
Thylacine	855	30	$3.35
Casino	452	40	$3.40
Otway Long Term	845	50	$4.50
Otway undiscovered	1,350	50 plus 5% pa	$6.00
Bass Basin			
Yolla White Ibis	355	20	$3.25
Bass undiscovered	500	20 plus 5% pa	$5.00
Gippsland Basin			
Esso/BHPB	5,945	250	$3.20
Patricia/Baleen	63	13	$3.00
Sole	196	15	$3.50
Basker Manta Gummy	219	20	$3.60
Kipper	620	50	$3.60
Longtom	438	25	$3.30
Gippsland Near Term	886	125	$4.00
Gippsland Long Term	750	100	$4.50
Gippsland Undiscovered	1,350	200	$5.50
North Gippsland Undeveloped	250	20 plus 5% pa	$4.00

The minimum producer price assumptions are based on an expectation of increasing costs over time to discover new gas reserves and to bring new production on line. This takes into account recent price trends and expectations (up to April 2008).

The contribution of CSG in Queensland and New South Wales is the other important component of the supply side assumptions. In Queensland it is assumed that continued expansion of the current production and reserves base occurs, with costs increasing over time as more expensive, less productive deposits are accessed. In New South Wales current exploration effort is assumed to succeed in establishing substantial production capacity, again with costs increasing over time as more expensive, less productive deposits are accessed. Total production capability from NSW CSG is assumed to reach around 400 PJ/a, across a range of price points, over the next 20 years.

The total production potential assumed under the gas market projection is represented in Figure 9. This represents the production that is assumed *potentially* to be available across a range of costs of production ranging from low to high cost gas. The *actual* level of production achieved is a model output rather than an input, and is determined by the supply/demand balance. It is likely to be significantly less than the potential production.

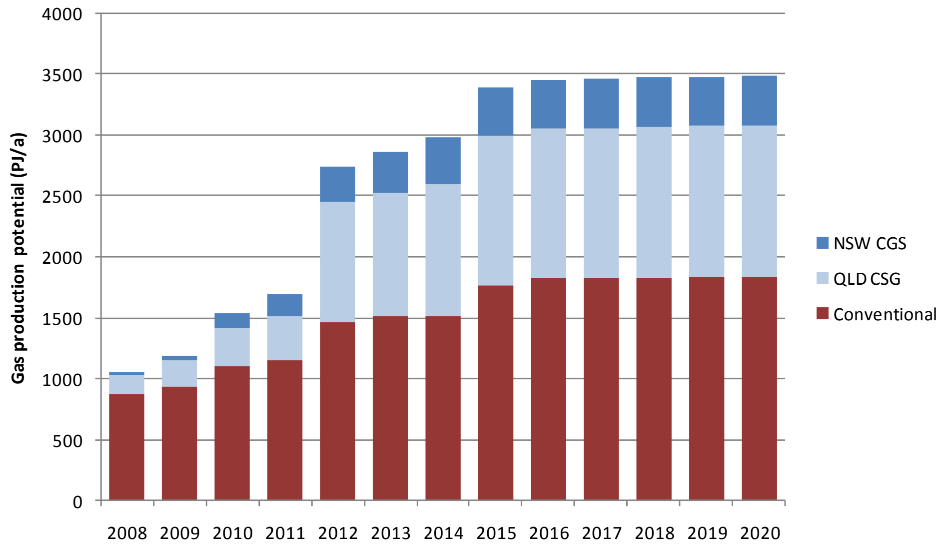
Figure 9 **Eastern Australian gas production potential, by state**



Data source: ACIL Tasman GasMark modelling

Figure 10 shows the corresponding production potential categorised by field type (conventional gas, Queensland CSG, NSW CSG)

Figure 10 **Eastern Australian gas production potential, by field type**



Data source: ACIL Tasman GasMark modelling

Figure 10 highlights the increasing contribution that CSG is expected to make to Eastern Australian gas supply availability, initially in Queensland and with an increasing contribution also from NSW.

6.1.2 Demand side assumptions

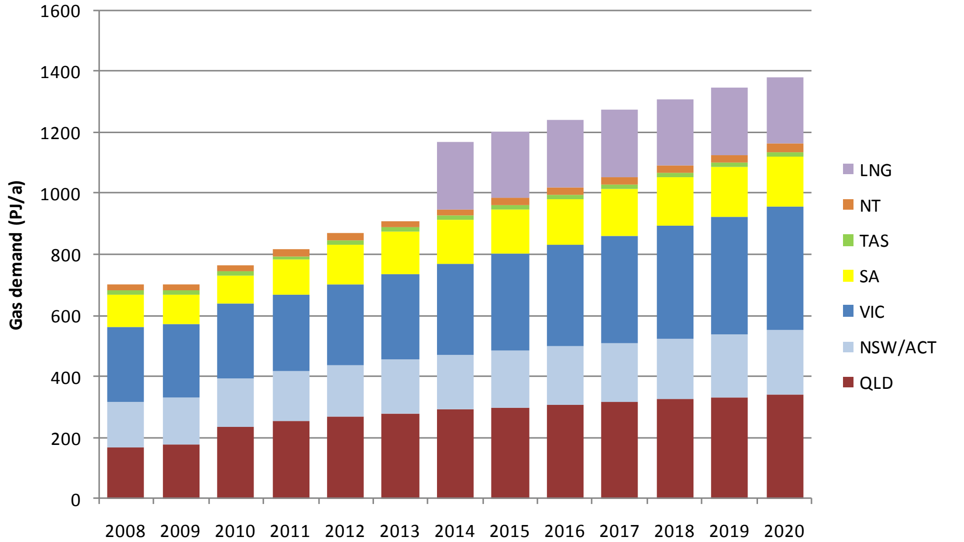
The assumptions include existing and future gas demand defined at individual site level for power generators and major industrial facilities such as minerals processing, fertiliser and cement works. Smaller industrial, commercial and residential demand is defined at regional level.

Assumed demand for gas in power generation takes into account the anticipated commencement of an ETS and the consequences of such a scheme for the demand for gas in power generation and for gas price tolerances.

One of the important uncertainties on the demand side relates to the potential impact of establishment of a liquefied natural gas (LNG) industry based on CSG production in Central and Southern Queensland. For purposes of this projection it has been assumed that LNG production commences in Central Queensland in 2014 at a rate of 4 million tonnes/year. The corresponding CSG requirement is assumed to be 220 PJ/a. This demand is satisfied from the assumed CSG production capability, and results in earlier demand for higher cost CSG production to meet domestic demand.

Figure 11 summarises the level of gas demand, by state, assumed in the gas modelling

Figure 11 **Eastern Australia gas demand, by state**



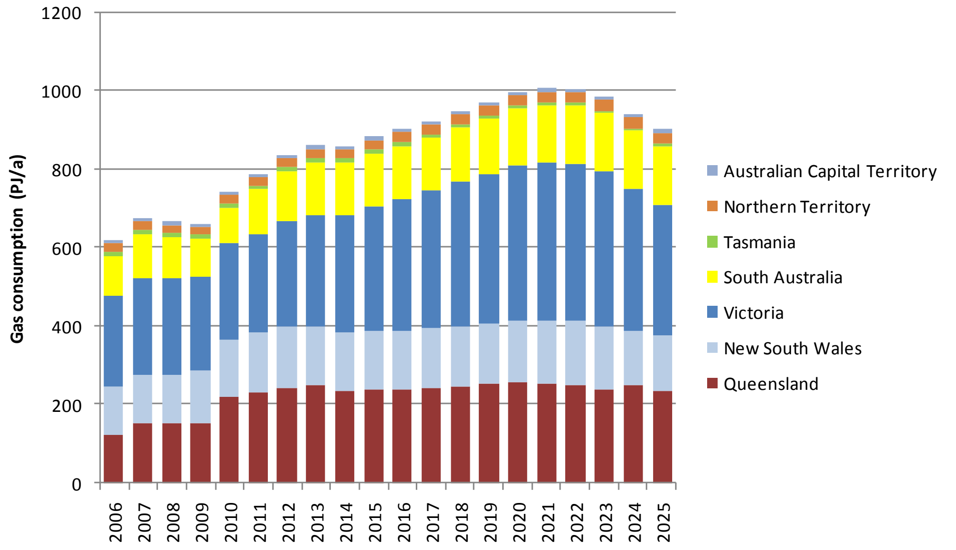
Data source: ACIL Tasman GasMark modelling

6.1.3 Pipeline assumptions

The projection includes a comprehensive representation of existing and committed transmission pipeline capacity as well assumed capacity expansions to meet anticipated market growth. Pipeline tariff assumptions reflect current reference tariffs for covered (regulated) pipelines, and current rack rate posted tariffs for non-covered (unregulated) pipelines. It is assumed that regulated tariff rates will be rolled-over, without discontinuity, at any subsequent review event.

6.2 Modelling results

Figure 12 **Modelled gas consumption, by state**



Data source: ACIL Tasman GasMark modelling

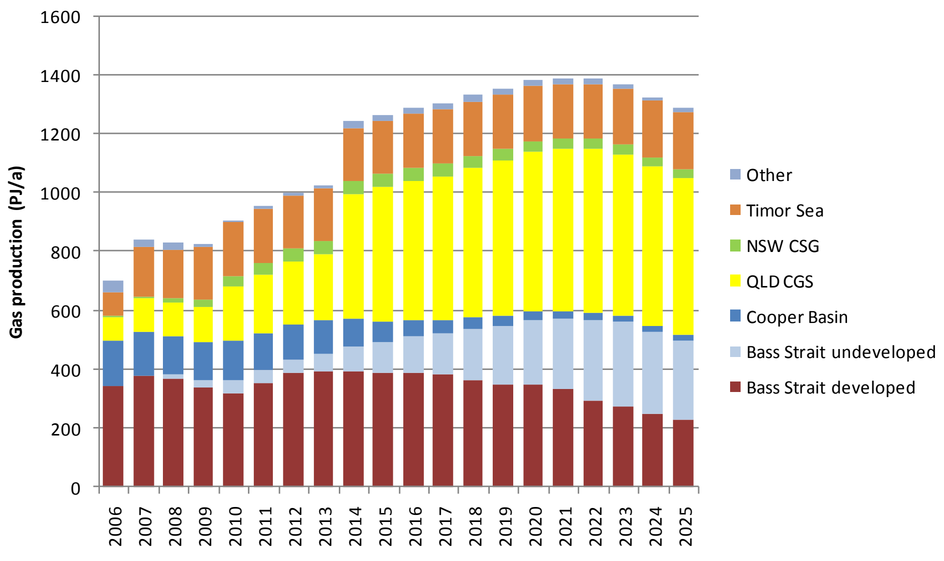
Overall, the consumption pattern reflects strong growth until around 2020, but then begins to decline as supply side constraints and rising gas prices see under-satisfaction of the market. This has potentially significant implications for new gas-fired power generation facilities: the risk of gas supply shortfalls within the first decade after construction will need to be mitigated through measures such as long-term supply contracting.

Victoria shows significant gas consumption growth, reflecting additional gas-fired generation introduced to replace brown coal plant. Queensland also shows strong consumption growth with further development of gas-fired generation located on or near CSG fields. Note that the Queensland consumption does not include gas used for LNG, which is consumed in the importing country.

Figure 13 summarises the results for gas production by source. Individual fields have been grouped together to highlight the overall patterns of new production. These results include production (of Queensland CSG) to support LNG manufacture. Important points to note with regard to the modelled results for gas production include:

- As with consumption, gas production peaks in around 2020 and then begins to decline as resource constraints and higher production costs reduce the uptake of gas in the market.
- Currently developed fields in Bass Strait (including Gippsland, Bass and Otway Basins) begin to decline from around 2013 and fall steeply over the period beyond 2020. Continued production in this region relies heavily on production from fields that are yet to be developed.
- The contribution from the Cooper Basin in Central Australia continues to decline, as it has for the past decade, and is insignificant during the second half of the modelling period.
- Queensland CSG grows strongly, with a step change on commencement of LNG production
- NSW CSG shows limited development. In practice there is potential for NSW CSG to perform more strongly subject to development of the necessary production capability and transportation infrastructure.

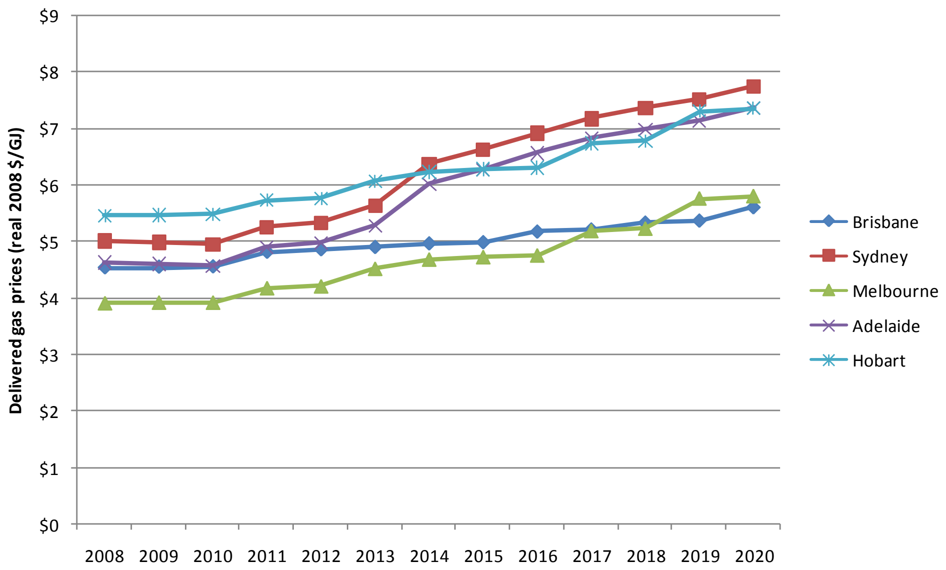
Figure 13 **Modelled gas production, by source**



Data source: ACIL Tasman GasMark modelling

Figure 14 summarises the modelled gas prices (wholesale) delivered to the city gate at each of the Eastern State capitals. The necessity to access more costly production sources, together with increased price expectations as a result of the value uplift associated with emission trading and the exposure to international energy prices resulting from establishment of LNG production sees prices rising in real terms in all state capitals. The price rises are steeper in Sydney and Adelaide, where diversion of Queensland CSG production into LNG reduces availability for transfer to southern states. The price effects in NSW could be ameliorated if CSG production and associated infrastructure development proceeds more rapidly than has been assumed.

Figure 14 **Modelled wholesale gas prices**

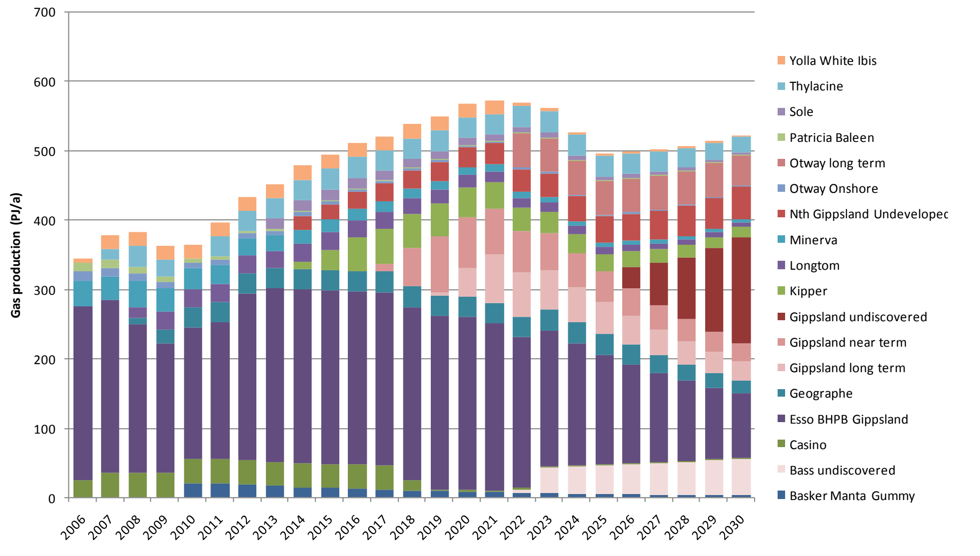


Data source: ACIL Tasman *GasMark* modelling

Victorian prices also rise strongly as a result of the decline in production from established fields in Bass Strait, and the greater reliance on new developments in deeper, more remote fields (Figure 15).

Prices in Brisbane are least affected, with local CSG production ameliorating the price pressure observed in other markets. Nevertheless, wholesale gas prices in Brisbane exceed $5.50/GJ (real 2008) by the year 2020.

Figure 15 **Modelled gas production in Victoria**



Data source: ACIL Tasman *GasMark* modelling

6.3 Western Australia gas assumptions

ACIL Tasman has assumed a real long-run gas price of $6.50/GJ in its modelling of the SWIS.

In the years prior to 2011/12, the delivered price of new gas contracts to Perth is substantially higher than existing contracts. This reflects increased ex-field asking prices from the North West Shelf producers and new fields assumed to enter the market in coming years. Existing contract prices are assumed to converge to this higher level as contracts expire.

The NewGen gas price is understood to be at a fixed rate (with CPI escalation provisions but no price re-openers) until 2023/24 at which point its price is assumed to become the market rate for Perth deliveries.

7 Electricity market modelling

7.1 Introduction

This chapter provides a description of the assumptions and model settings used to undertake simulation modelling of both the NEM and the SWIS followed by a presentation of modelling results. The chapter provides the broad approach taken in this aspect of energy market modelling, including the development of both supply and demand inputs. The data inputs for *PowerMark* are intensive, with demand, outages, supply, interconnector capacity and fuel costs required for each region and each hour of the 12 year (2008 to 2020) projection. A more detailed description of these inputs is provided in Appendix A which provides extracts from ACIL Tasman's generator database and the derivation of hourly demand projections.

7.2 Modelling assumptions

The assumptions covered in this chapter are considered under four headings:

- **Electricity consumption**, including energy and maximum demand projections which take into account existing energy conservation measures, distributed renewable generation and the effects of the demand side response to the higher prices resulting from an ETS.
- **New entrant costs**, this concerns firstly the assumptions made about the generation technologies available by 2020 and the long run marginal cost (LRMC) they need to cover in order to enter the market.
- **Market supply**, which covers the power stations available to generate in the market and includes assumptions about retirements and new entry as well as planned and unplanned outages.
- **Contract cover**, sets out ACIL Tasman's assumptions concerning the proportion of energy generated in any period that is covered by swap contracts. This is an important input to the modelling as the proportion of generation that is uncontracted affects the way in which *PowerMark* models price outcomes.

7.3 Electricity consumption

Growth in annual energy and peak load are important inputs to the electricity market simulation process. Peak load is the average maximum instantaneous demand for electricity placed on the system over a given period of time, measured in MW. Energy is the amount of electricity used by the system during a given period of time, measured in GWh (or MWh).

These two inputs, described on a region-by-region basis, broadly describe the energy consumption of the NEM and the SWIS.

For the business as usual scenario we have used the official forecast of regional summer and winter peak demands and annual energy to 2017 published by NEMMCO in its 2007 Statement of Opportunities (SOO). Projecting forward to 2020 we have used the annual average growth rates for energy consumption over this period to project both energy and maximum demand to 2020.

The energy and maximum demand projections adopted from the SOO are the "medium" energy and "50% probability of exceedence" maximum demand. The energy forecast is related to a set of underlying GDP growth assumptions – put simply, the energy forecast used in the scenarios assumes the most likely economic growth conditions in each region of the NEM – which are developed by NIEIR. The maximum demand forecast takes into account typical ambient temperature conditions and is developed by each of the regional transmission authorities.

Table 18 to Table 20 provide details of the energy forecasts and Table 21 to Table 23 provide details of the maximum demand forecasts used in the modelling. The modelling requires a load forecast to 2020 and we have linearly extrapolated the energy forecast provide in the SOO to this year and taken the inferred growth rates from the extrapolation and applied them to the peak loads. In other words, we assume a convergence of the growth rates in peak loads and annual energy post 2017.

Table 18 **Energy requirement by region (GWh) – 10% case**

	NSW	Qld	SA	Tas	Vic	NEM	SWIS	Total
2008	80,697	55,167	12,912	10,373	51,725	210,874	15,878	226,752
2009	81,911	57,314	13,205	10,594	51,047	214,071	17,072	231,143
2010	82,961	59,557	13,378	10,776	51,391	218,063	17,822	235,885
2011	82,653	60,790	13,360	10,729	51,266	218,798	18,173	236,971
2012	82,453	61,897	13,315	10,677	51,102	219,444	18,429	237,873
2013	83,033	63,466	13,351	10,699	51,403	221,952	18,475	240,427
2014	82,537	63,975	13,203	10,637	51,015	221,367	18,543	239,910
2015	82,869	65,024	13,168	10,692	51,127	222,880	18,498	241,378
2016	83,689	66,507	13,207	10,736	51,603	225,742	18,469	244,211
2017	83,010	66,891	13,078	10,620	51,130	224,729	18,639	243,368
2018	84,304	68,865	13,276	10,789	51,821	229,055	18,507	247,562
2019	84,707	70,044	13,298	10,821	52,000	230,870	18,830	249,700
2020	86,057	71,997	13,470	10,975	52,762	235,261	18,944	254,205

Data source: NEMMCO SOO and IMO with adjustment by ACIL Tasman for demand responses to an ETS

Table 19 **Energy requirement by region (GWh) – 20% case**

	NSW	Qld	SA	Tas	Vic	NEM	SWIS	Total
2008	80,697	55,167	12,912	10,373	51,725	210,874	15,878	226,752
2009	81,911	57,314	13,205	10,594	51,047	214,071	17,072	231,143
2010	82,961	59,557	13,378	10,776	51,391	218,063	17,822	235,885
2011	82,653	60,790	13,360	10,729	51,266	218,798	18,173	236,971
2012	82,026	61,576	13,246	10,621	50,837	218,306	18,429	236,735
2013	82,598	63,134	13,281	10,643	51,134	220,790	18,379	239,169
2014	81,947	63,518	13,108	10,561	50,651	219,785	18,446	238,231
2015	81,428	63,894	12,939	10,506	50,238	219,005	18,366	237,371
2016	82,588	65,632	13,033	10,595	50,924	222,772	18,148	240,920
2017	82,247	66,276	12,957	10,522	50,660	222,662	18,393	241,055
2018	81,936	66,931	12,903	10,486	50,365	222,621	18,337	240,958
2019	82,782	68,452	12,996	10,575	50,818	225,623	18,302	243,925
2020	84,102	70,361	13,164	10,726	51,562	229,915	18,514	248,429

Data source: NEMMCO SOO and IMO with adjustment by ACIL Tasman for demand responses to an ETS

Table 20 **Energy requirement by region (GWh) – BAU**

	NSW	Qld	SA	Tas	Vic	NEM	SWIS	Total
2008	80,697	55,167	12,912	10,373	51,725	210,874	15,878	226,752
2009	81,911	57,314	13,205	10,594	51,047	214,071	17,072	231,143
2010	82,961	59,557	13,378	10,776	51,391	218,063	17,822	235,885
2011	84,054	61,820	13,586	10,910	52,135	222,505	18,173	240,678
2012	85,444	64,142	13,798	11,064	52,955	227,403	18,741	246,144
2013	86,945	66,457	13,980	11,203	53,825	232,410	19,145	251,555
2014	88,432	68,545	14,146	11,397	54,659	237,179	19,417	256,596
2015	90,075	70,679	14,313	11,621	55,573	242,261	19,819	262,080
2016	91,765	72,924	14,481	11,772	56,582	247,524	20,075	267,599
2017	93,270	75,158	14,694	11,933	57,450	252,505	20,437	272,942
2018	94,723	77,377	14,917	12,122	58,225	257,364	20,794	278,158
2019	96,258	79,596	15,112	12,297	59,091	262,354	21,158	283,512
2020	97,792	81,815	15,307	12,472	59,956	267,342	21,528	288,870

Data source: NEMMCO SOO and IMO with adjustment by ACIL Tasman for demand responses to an ETS

Table 21 **Maximum demand by region (MW) – 10% case**

	NSW	Qld	SA	Tas	Vic	SWIS
2008	14,070	9,461	2,990	1,781	9,198	3,521
2009	14,370	9,883	3,089	1,816	9,263	3,791
2010	14,650	10,268	3,146	1,839	9,409	3,924
2011	14,721	10,482	3,127	1,842	9,441	4,037
2012	14,784	10,656	3,130	1,835	9,438	4,097
2013	15,032	10,941	3,179	1,836	9,526	4,131
2014	15,064	11,030	3,190	1,831	9,503	4,183
2015	15,208	11,200	3,188	1,837	9,530	4,201
2016	15,322	11,458	3,224	1,840	9,623	4,226
2017	15,308	11,528	3,205	1,815	9,560	4,278
2018	15,627	11,878	3,260	1,843	9,729	4,261
2019	15,764	12,092	3,276	1,850	9,785	4,345
2020	16,074	12,440	3,329	1,878	9,949	4,378

Data source NEMMCO SOO and IMO with adjustment by ACIL Tasman for demand responses to an ETS

Table 22 **Maximum demand by region (MW) - 20% case**

	NSW	Qld	SA	Tas	Vic	SWIS
2008	14,070	9,461	2,990	1,781	9,198	3,521
2009	14,370	9,883	3,089	1,816	9,263	3,791
2010	14,650	10,268	3,146	1,839	9,409	3,924
2011	14,720	10,482	3,127	1,842	9,441	4,037
2012	14,707	10,600	3,114	1,826	9,389	4,097
2013	14,953	10,884	3,163	1,827	9,476	4,110
2014	14,956	10,951	3,167	1,818	9,435	4,161
2015	14,943	11,005	3,132	1,805	9,365	4,171
2016	15,120	11,308	3,182	1,816	9,496	4,152
2017	15,167	11,422	3,175	1,798	9,472	4,222
2018	15,188	11,544	3,168	1,791	9,455	4,222
2019	15,406	11,817	3,202	1,808	9,562	4,223
2020	15,708	12,158	3,254	1,835	9,723	4,279

Data source NEMMCO SOO and IMO with adjustment by ACIL Tasman for demand responses to an ETS

Table 23 **Maximum demand by region (MW) - BAU**

	NSW	Qld	SA	Tas	Vic	SWIS
2008	14,070	9,461	2,990	1,781	9,198	3,521
2009	14,370	9,883	3,089	1,816	9,263	3,791
2010	14,650	10,268	3,146	1,839	9,409	3,924
2011	14,970	10,660	3,180	1,873	9,601	4,037
2012	15,320	11,042	3,244	1,902	9,780	4,166
2013	15,740	11,457	3,329	1,923	9,975	4,281
2014	16,140	11,818	3,418	1,962	10,182	4,380
2015	16,530	12,174	3,465	1,997	10,359	4,501
2016	16,800	12,564	3,535	2,018	10,551	4,593
2017	17,200	12,953	3,601	2,039	10,742	4,691
2018	17,558	13,346	3,662	2,071	10,931	4,787
2019	17,914	13,740	3,723	2,103	11,119	4,882
2020	18,266	14,137	3,783	2,134	11,306	4,975

Data source: NEMMCO SOO and IMO with adjustment by ACIL Tasman for demand responses to an ETS

The method for converting the energy and maximum demand projections into a standard unbiased estimator of hourly loads in each region is set out in Appendix A.

7.4 New entrant costs

In developing the scenarios ACIL Tasman assumes that the new entry cost provides a long-term ceiling on pool prices (on a load-weighted basis). The logic of this approach derives from the view that if pool prices exceed new entry costs for any period of time, new investors will be attracted into the market until prices are driven back below the long-term ceiling. These new investors may include electricity retailers induced to build plant of their own if existing generators were to demand contract strike prices above new entry costs.

New entry costs are not used directly within *PowerMark* modelling. However, they are used by ACIL Tasman analysts as a guide as to when and where to bring new entrants into the simulations (as capacity additions assumptions).

The new entry costs are estimated within a financial model that encompasses assumptions concerning thermal efficiency, the cost of gas, the weighted average cost of capital and the capital costs of bringing a plant into commercial operation.

In the projection, new plant is introduced whenever the dispatch weighted pool price of the new entrant in the relevant region achieves or is very close to achieving its new entry cost. This requires that construction be begun some two years for CCGTs, and three years for coal fired plant, before new entry levels are reached.

This process brings in new capacity under commercial incentives and we check this rate of increase to see if it is affecting reserve margins and the probability of a change in unserved energy levels. In fact the capacity of new entry plant in this project brings about a slight reduction in the reserve plant margin up to 2020.

To estimate the new entry life cycle cost ACIL Tasman uses a discounted cash flow financial model that requires a number of key assumptions to be made which are provided in Appendix A.

Table 24 provides the estimates of the annualised fixed costs (capital and fixed O&M) of greenfield generation projects in the NEM. The numbers are based on a discounted cash flow (DCF) model using the long run marginal cost input assumptions presented in this chapter. The values presented are the fixed costs/kW of installed capacity per year.

Table 24 **Annualised capital and fixed O&M costs (nominal $/kW/year)**

Year	CCGT	Black coal	Brown coal	OCGT
2008	$126	$226	$257	$85
2009	$128	$231	$262	$87
2010	$131	$236	$267	$89
2011	$133	$241	$273	$91
2012	$136	$246	$279	$92
2013	$139	$251	$284	$94
2014	$142	$256	$290	$96
2015	$145	$262	$296	$98
2016	$148	$267	$302	$100
2017	$151	$273	$309	$102

Note: These values represent the annualised project capital plus fixed O&M costs required to be recovered each year. Data source: ACIL Tasman analysis

We have assumed that some of the low and zero emission technologies now under development are available as new entrants by then and some are still in their demonstration stages. We have assumed that geothermal energy is a technically and commercially viable new entrant in 2020 with the main constraint on its growth being the time taken to drill and develop new generation and build the interconnection needed to bring this energy to market.

We assumed that carbon capture and storage for coal fired plants is at the demonstration rather than commercial stage, as are integrated gasifying and combined cycle (IGCC) CCS plants.

We assume nuclear is not an option in Australia in 2020. The current Australian Government has ruled it out of Australia's generation mix and, given the time required to put in place a licensing regime and for a nuclear plant to planned, approved and built, it is very unlikely that one would be contributing to Australia's generation by 2020.

7.5 Market supply

When taken together with the electricity consumption forecast, the assumptions regarding plant additions and retirements determines the supply-demand balance and are critical to the modelling results. Table 25 below outlines the committed or advanced withdrawals and additions of plant assumed to be common in each of the scenarios. In addition to the committed plant in the table below, ACIL Tasman also includes assumed geothermal plant in Queensland and South Australia.

Table 25 **Near-term additions to and withdrawals from generation capacity by region**

Portfolio	Generator	Type	Nameplate capacity (MW)	Date-on	Date-off
Victoria					
AGL Energy	Bogong	Hydro	150	Oct 2009	
New South Wales					
TRUenergy	Tallawarra	CCGT/Gas	410	Jul 2008	
BBP	Uranquinty	OCGT/Gas	700	From Feb 2009	
Delta	Colongra	OCGT/Gas	670	Dec 2009	
Delta	Mt Piper U1-U2	Black coal	+90MW per unit	Assumed not to proceed	
Eraring	Eraring	Black coal	+90MW per unit	Assumed not to proceed	
South Australia (note wind farms must be scheduled generators in SA)					
Origin Energy	Quarantine	OCGT	+120	Dec 2008	
AGL Energy	Hallett wind farm	Wind	95	April 2008	
NP Power	Lake Bonney Stage 2	Wind	159	July 2008	
Trust Power	Snowtown	Wind	88	July 2008	
AGL Energy	Hallett 2 wind farm	Wind	71	Nov 2009	
IPM	Snuggery	OCGT	-42		June 2010
Queensland					
Queensland Gas Co	Condamine	CCGT/Gas	140	Feb 2009 OCGT, CCGT by Aug 2009	
ERM	Braemar 2	OCGT/Gas	520	July 2009	
CS Energy	Swanbank B	Black coal	375		Jul 2011
Origin Energy	Darling Downs	CCGT	630	March 2010	
Tasmania					
Alinta	Tamar Valley PS	CCGT/Gas	200 + 40 (OCGT)	Jul 2009	
Bell Bay Power	Bell Bay PS	Gas	-240		March 2009

Data source: The NEMMCO 2007 SOO and ACIL Tasman database

7.6 Contract cover

Contract cover measures the extent to which generators have their pool price exposure covered by financial swap contracts (two-way hedges)[4]. In modelling pool markets, the level of swap contract cover is a driving factor in price and dispatch outcomes. Based solely on short-run analysis, a generator will usually offer contracted capacity at marginal cost (save for below marginal cost bids in respect of 'MinGen' and ramp-up needs[5]), and will bid to maximise net revenues from the remaining uncontracted capacity.

The extent of swap contract cover across the whole market, whether expressed as a proportion of available capacity or of market demand, can only be estimated as it is not a published statistic. Individual portfolios, of course, are keenly aware of the position in respect of their own business — but this information is not reported or divulged.

While swap contract levels are not publicly known, portfolio bid stacks do allow the level of capacity bid at marginal cost to be inferred.

Within PowerMark, specification of swap contract levels means specification of the amount of capacity to be offered at or below marginal cost. It is estimated by reference to recent market experience and adjusted over time on the basis of an analysis of contracting incentives.

Swap contract cover in the initial years of the NEM was unsustainably high and, in combination with overcapacity, led to significant financial pressure on generators. Generators reduced overall swap contract cover in 2000 and 2001, as retailers sought to switch to some level of pool exposure following a number of years of very low pool prices. This was also the period when most vesting contracts fell away. In 2001, high pool prices led to heavy contracting by retailers in 2002 with considerable levels of contracts written out three to five years. The cool summer of 2002 and 2003 meant that

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4 Caps impact on generator offering behaviour only to the extent that they relate to plant capacity that would normally be off-line.

5 'MinGen' (for minimum generation) is the estimated minimum level at which a plant can be technically and economically operated (for flame control and damage limitation). Generators usually offer this level of capacity at near zero or substantially negative prices in order to avoid being offloaded by the central dispatcher. It is rare — but does occur — for the pool price to settle at a negative "offload" price. Generators also tend to offer capacity at below marginal cost for periods when they are intent on 'ramping-up' in order to have the ability to offer greater amounts of capacity in a subsequent period, when pool prices are expected to be higher.

generators again had proportionally high levels of contract cover when compared with actual load. Analysis of generator offer curves suggests that contract levels returned towards the 2001 levels in 2004 and 2005 and have not changed noticeably in 2006/07.

ACIL Tasman's analysis to date indicates that the lowest of the off-peak hours are heavily contracted as a proportion of load, whereas caps and other more exotic options are added to swaps in the peak periods to provide cost effective risk management.

ACIL Tasman establishes proxy values of swap contract cover for recent historical periods by 'reverse engineering' the swap contract cover and swap contract target assumptions such that they replicate actual power station dispatch and pool prices when actual demand data and outage data are substituted for projected demand and outages. The estimates derived in that way are plausible numbers in the opinion of market participants familiar with them. We expect the level of contract cover in the market to stabilise, on a long term basis, at about 86% of all demand. Based on our modelling, this allows new entrants a reasonable level of contract cover as well as maintaining the contract levels of existing base load plant.

Over the last few years, some vertical integration has occurred where generation portfolios have been put together with retail portfolios. We do not explicitly model vertically integrated entities. The assumed level of swap and cap contract cover for each entity is our proxy for vertically integrated generation incentives.

Over the 2008 to 2020 period modelled it is possible that contract cover may vary from its longer term average. Some existing major base load power stations carrying high levels of contract cover are being projected to exit the market and being replaced by base load generation mainly from gas and geothermal energy. It is possible as power stations exit, contract cover in the market may fall before it is picked up by new entrants. Gas fired CCGTs when they first enter are unlikely to have the same capacity factors in the market as coal fired plant and they may not wish to take up such high levels of contract cover. It is possible that contract cover may vary year to year causing some price volatility as it does so.

7.7 Assumptions for the SWIS

7.7.1 Demand assumptions

PowerMark WA settles the market each half hour and requires a projected half hourly load trace as input. The projected load trace is derived by projecting the actual half hourly load trace to match the forecast for the sent-out annual peak demand and annual energy.

The analysis has relied upon the Independent Market Operator (IMO) medium growth forecast of peak demands and annual energy to 2017 published in July 2007 by the IMO in its 2007 Statement of Opportunity (SOO). For peak demand we use the forecast at the 50% probability of exceedence (POE) level meaning that the peak demand forecast is expected to be exceeded one year in two. The IMO load forecast is based on medium economic growth outlook as forecast for the IMO by NIEIR.

The load projection for beyond 2017 by ACIL Tasman is at the same average growth as forecast for the eight years to 2017 as published by the IMO in the 2007 SOO. Table 26 shows the projected annual peak, average and minimum load requirements up to 2020.

Table 26 **Forecast annual demand (peak and energy)**

	Summer peak demand	Annual minimum demand	Annual average demand	Annual energy (GWH sent-out)
2008	3,521	1,178	1,813	15,878
2009	3,791	1,267	1,949	17,072
2010	3,924	1,323	2,034	17,822
2011	4,037	1,349	2,075	18,173
2012	4,166	1,391	2,139	18,741
2013	4,281	1,421	2,186	19,145
2014	4,380	1,441	2,217	19,417
2015	4,501	1,471	2,262	19,819
2015/16	4,593	1,490	2,292	20,075
2016/17	4,691	1,517	2,333	20,437
2017/18	4,785	1,541	2,370	20,764
2018/19	4,881	1,566	2,408	21,096
2019/20	4,973	1,591	2,447	21,434

Data source: ACIL Tasman with data from IMO

7.7.2 Supply assumptions

Future capacity to supply electricity during the projection period is dependent on:

- capacity and type of existing generation
- capacity, type and timing of plant retirements
- capacity, type and timing of new plant (new entrants)
- frequency and length of maintenance programmes as well as assumed forced outage rates.

When taken together with the electricity load forecast, the assumptions regarding plant additions and retirements will determine the supply-demand balance.

ACIL Tasman has taken into account information obtained from the market as well as published by the IMO in its SOO when constructing the assumptions regarding the timing of new plant and withdrawal of existing plant.

Table 27 outlines the committed or advanced withdrawals and additions of plant assumed to be common in each of the scenarios.

Table 27 **Near term additions to and withdrawals from generation capacity**

Portfolio	Unit/Generator	Type	Unit size (MW)	Date-on	Date-off
Verve Energy	Kwinana A (2 units)	Steam turbine/Natural gas	223		Apr-09
Verve Energy	Kwinana B (2 units)	Steam turbine/Natural gas	218		Aug/Sep-08
Verve Energy	Kwinana Gas Turbine	Gas turbine/Natural gas	21		Mar-11
Verve Energy	Geraldton	Gas turbine/Distillate	21		Dec-12
Griffin Power Pty Ltd	Bluewaters U1	Steam turbine/Black coal	204	Dec-08	
Griffin Power Pty Ltd	Bluewaters U2	Steam turbine/Black coal	204	Nov-09	
Western Australian Biomass Pty Ltd	Manjimup Biomass	Steam turbine/Biomass	40	Oct-09	
Newgen Neerabup Pty Ltd	NewGen Neerabup Gas Turbine (units 1&2)	Gas turbine/Natural gas	327	Nov-09	
NewGen Power Kwinana Pty Ltd	NewGen Kwinana CCGT	Gas turbine combined cycle/Natural gas	240	Sep-08	
NewGen Power Kwinana Pty Ltd	NewGen Kwinana Steam Turbine	Steam turbine/Natural gas	80	Sep-08	

Data source: The IMO SOO and ACIL Tasman database

SRMC

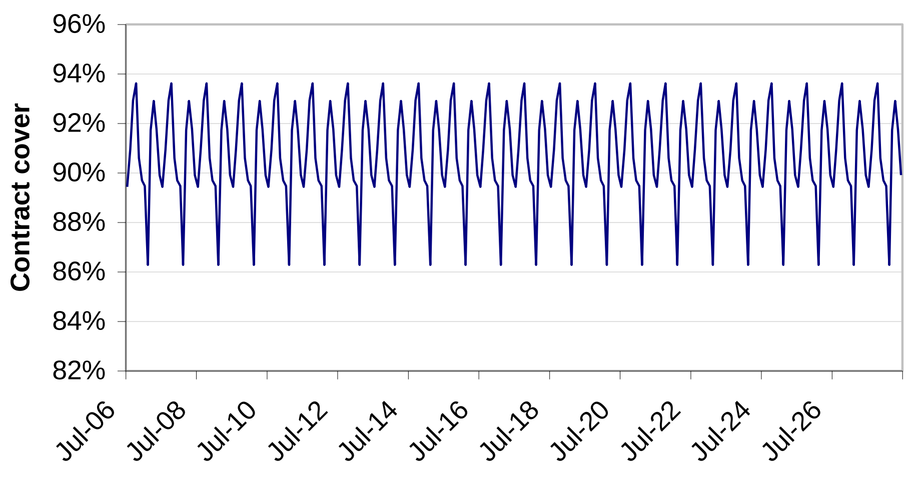
The SRMC of plant is the STEM offer price used of generators up to the contracted level and is used to allocate contracts to individual plants. In general, the SRMC is the fuel cost plus variable operation and maintenance (O&M) costs.

Contract cover

Different levels of contract cover during peak and off-peak periods are assumed in ACIL Tasman's model of the SWIS. ACIL Tasman assigns a level of contract cover to each station based on an analysis of the relative competitiveness of the station.

Overall contract cover by month is shown in Figure 16. The average contract cover for the SWIS is around 90%. This level is somewhat higher than values ACIL Tasman use for the NEM (typically around 80-85%) due to the increased importance of bilateral contracts in the SWIS.

Figure 16 **Monthly contract cover for whole market**



Data source: ACIL Tasman analysis

Contract price

The modelling is based on the assumption that the bilateral contract revenue will be the total of capacity revenue (i.e. capacity payments minus capacity refunds) plus STEM revenue based on the STEM price plus a small contract margin. Retailers have the option of buying energy out of the STEM and obtaining capacity from OCGT plant with low fixed costs which will effectively provide a cap on contract prices.

Generator offer curves

Generator offer curves are constructed in a similar way to those in the NEM but with a price cap initially of $159.84/MWh for gas and coal fired fuel plant and $464.00/MWh for liquid fuel plant. The structural differences in market design in the SWIS is expected to result in generator offer curves which more closely match the marginal energy costs.

The current market rules states that generator bids and offers into the STEM must reflect SRMC. ACIL Tasman sees this rule as unsustainable and undesirable due to the longer-term impact it will have on generation investment – in particular, the mix of generation on the SWIS. All else being equal, the enforcement of the SRMC bidding rule will hinder investment in baseload/intermediate generation in favor of peaking stations.

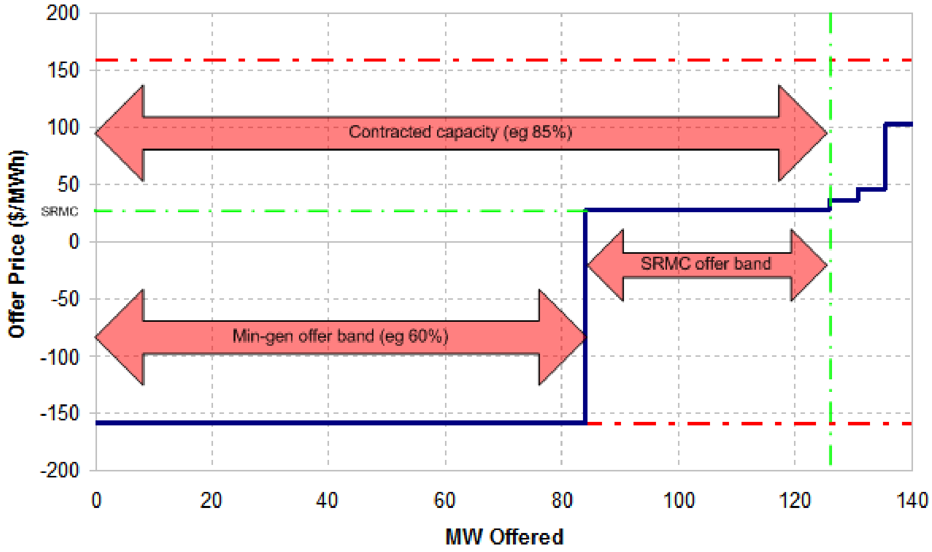
This in turn, results in higher average STEM prices which will flow through to higher bilateral contract prices.

The unit offer curve is comprised of a number of segments:

- Minimum generation level: typically associated with coal plant, reflecting the lowest level of stable generation before unit decommitment. For coal plant this is normally in the range 40-50% of sent-out capacity. This quantity is offered at a price level which approximates the STEM floor price (currently –$159.84/MWh)
- SRMC band: the residual cumulative capacity up to the units assumed contract level. The volume in this band is priced at the units SRMC
- Residual bands: capacity above the assumed contract level up to unit capacity.

These bands are shown graphically in Figure 17.

Figure 17 **Offer curve construction**



Capacity above contract level (residual bands) are offered to the STEM at three price points:

- mid-point between SRMC and LRMC
- LRMC
- mid-point between LRMC are relevant market cap price for that unit.

The capacity offered in each of these three residual bands are equivalent to: (units capacity – contracted capacity)/3.

Capacity payments

The modelling does not incorporate an explicit capacity auction. The plant program in the modelling is determined through commercial entry considerations. Should generation investment using this approach fall short of the regulated requirement, OCGT plant (having the lowest fixed costs of the various generation technologies) are introduced until the regulated level is met.

The capacity price is taken to be the fixed cost of a low priced OCGT. The fixed cost includes fixed O&M costs plus an allowance for capital. This approach has been adopted because retailers, in negotiating for capacity credits, have the option of constructing such a plant to provide their own capacity credits. ACIL Tasman believes this approach would represent an effective price cap for the provision of capacity credits.

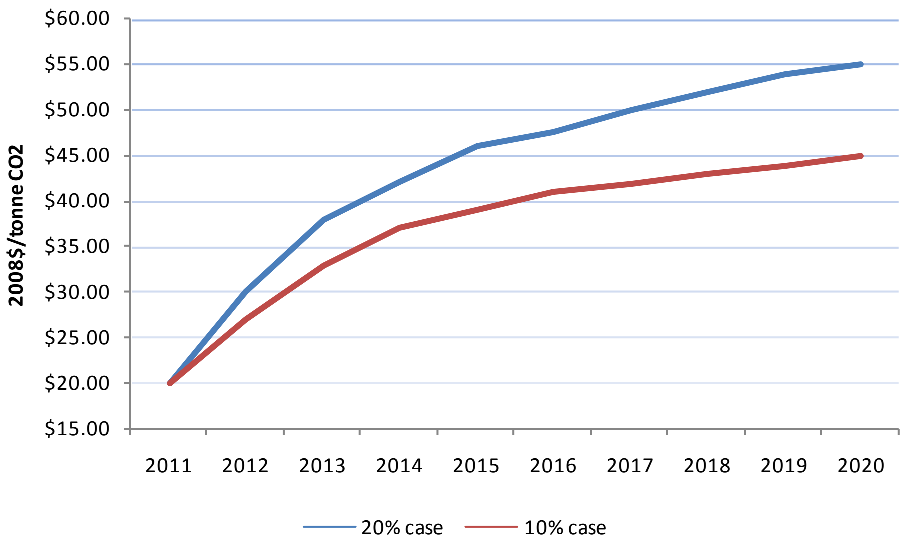
8 Electricity market results

The project began with electricity market modelling of the year 2020 as a starting point in finding the emissions permit prices that would deliver 10% and 20% savings in the NEM. Further modelling was then undertaken to estimate likely electricity demand responses (using the Tasman Global GE model) to the higher electricity prices in 2020 and the gas prices likely to result from considerably higher demand for gas for electricity generation in eastern Australia. An assessment was also made of the likely level of renewables generation given the expanded MRET scheme and the higher prices of electricity resulting from an ETS.

In a circular process these results were then brought back to the *PowerMark* electricity market models of the NEM and the SWIS and each year was then simulated from 2008 up to 2020 for both the 10% and 20% cases. A business as usual (BAU) case was also modelled to allow some comparison of the development path the market would take without an ETS. The BAU case was without both an ETS and an expanded MRET scheme, both of which are recent policy initiatives currently under further development.

Figure 18 shows the permit prices in (real) 2008 dollars for both cases. The price starts at $20/tonne CO_2–e in the first year but needs to increase fairly rapidly if it is to achieve the change in generation and the emission savings required by 2020.

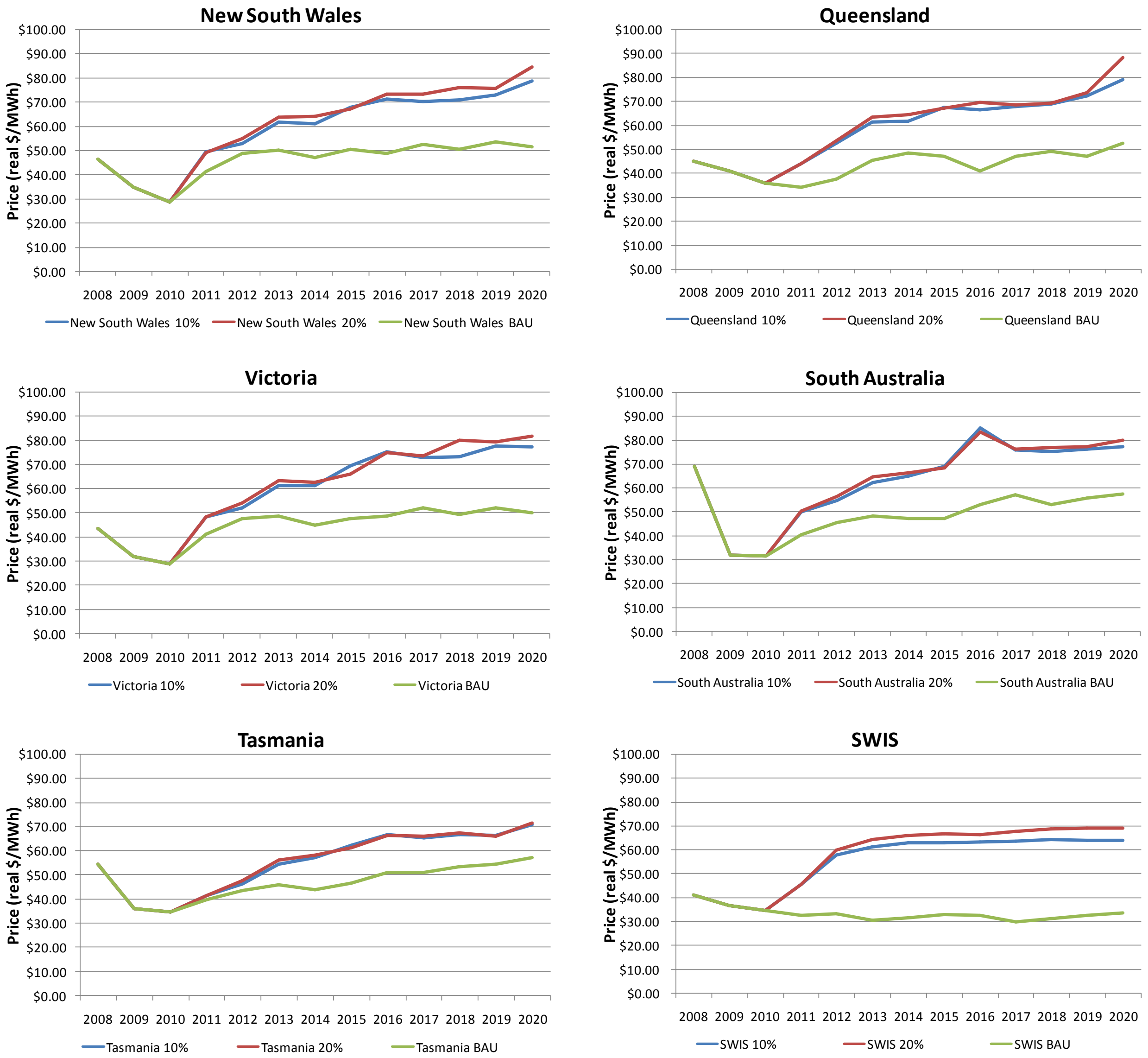
Figure 18 **Modelled permit prices (2008$/tonne $C0_2$)**



Data source: ACIL Tasman modelling

The average (time weighted) pool prices (NEM) and STEM prices (SWIS) under the 3 scenarios are shown in Figure 19.

Figure 19 **Regional pool prices by NEM region and STEM prices in the SWIS ($/MWh, $2008)**



Data source: ACIL Tasman modelling

The SWIS prices shown Figure 19 represent prices from the Short Term Energy Market (STEM prices) in the WA Wholesale Electricity Market (WEM) only and are not directly comparable to NEM pool prices. This is because, in the WEM, the STEM is only one component of market revenue available to generators. The WEM is comprised of two sub-markets: an energy trading market and a reserve capacity market. The majority of energy in the WEM is traded bilaterally, with the day-ahead STEM providing the market mechanism that facilitates trading around bilateral positions. The reserve capacity market is the mechanism whereby generators receive payment for provision of capacity, which can be a result of bilateral trades or the reserve capacity auction conducted by the IMO.

Table 28 shows the indicative pass through of the increases in electricity costs through the ETS and the RET to retail tariffs. 2008 tariffs are representative of the allowance made recently by regulators for the components of retail costs. Energy costs include pool and contracting costs and network costs include an allowance for both transmission and distribution.

Table 28 **Indicative pass through to retail tariffs, cents/kWh ($2008)**

	2008	2020		
		BAU	10% case	20% case
Cost of energy	5.8	7.3	9.4	9.9
Network costs	5.5	5.5	6.0	6.0
Retail margin	1.5	1.5	1.5	1.5
RET cost (20% by 2020 target)			0.9	0.9
Total	12.8	14.3	17.8	18.3

Data source: ACIL Tasman modelling

Additional energy costs are incurred in the BAU as the higher real costs of gas and coal are passed through to electricity consumers in higher BAU pool prices. The higher energy costs in the 10% and 20% cases reflect the additions to pool prices between 2008 and 2020 in these cases and added to the allowance regulators currently make for energy purchasing costs. Network costs have also been increased slightly to allow for additional network investment that will be needed and finally an allowance for the RET cost retail consumers will be required to pay under the 20% RET has been included in the 10% and 20% cases.

8.1 Plant retirements and new entry

In the modelling of the 10% and 20% cases we have withdrawn plant when its net revenue (pool revenue less fuel, emissions permit costs, fixed and variable O & M costs) reaches zero. In the 10% case most of the plant withdrawn in this way is Victorian brown coal plant from the Latrobe Valley. Energy Brix (195MW) is first to be withdrawn followed Hazelwood (1640MW) and Yallourn (1480MW) and Loy Yang B (1020MW). Loy Yang B buys its coal from the Loy Yang A mine and while Loy Yang A remains generating because of its low coal costs, Loy Yang B is forced to close as its costs are higher.

In South Australia both Playford and Northern close in the 10% case. Redbank in NSW and Collinsville and Callide B in Queensland also close in the 10% case.

Newport power station, a gas fired steam generating power station near Melbourne in Victoria is assumed to be retired in both the 10% and 20% cases as its net revenue falls to negative levels from about 2015 onwards.

Table 29 and Figure 20 show the plant retirements and new entry for the 10% case and Table 30 and Figure 21 show the outcome for the 20% case.

Table 29 **NEM plant retirements and new entry between 2011 and 2020 (MW) - 10% case**

	NSW	Vic	Qld	SA	Tas	NEM
Retirements						
Brown coal		4,335				4,335
Black coal	150		890	770		1,810
Natural gas steam		500				500
Total	150	4,835	890	770	0	6,645
New Entry						
CCGT	0	3,250	1,500	0		4,750
OCGT	200	1,340	250	150		1,940
Biomass	85	57	114	28		284
Solar	200	320	200	200		920
Wind	1,924	2,251	0	103		4,278
Geothermal	0	0	750	750		1,500
Coal	0	0	0	0		0
Total	2,409	7,218	2,814	1,231		13,672

Data source: ACIL Tasman modelling

Note: This table shows only replacement generation from 2011 to 2020.

The retired capacity is replaced from 2011 to 2020 with 4,750MW of CCGT in Victoria and Queensland, 1,940MW of open cycle peaking gas turbines, 1500MW of geothermal plant assumed to enter the market in South Australia and Queensland and 4,278MW of wind capacity in NSW, Victoria and South Australia, 920MW of solar capacity in NSW, Victoria, South Australia and Queensland and 284MW of biomass in the same states.

The renewable sources generally run at lower capacity factors than thermal generation. We have assumed wind runs at 30% and solar generation at 24%. As a consequence much more capacity is needed to replace the black and brown coal energy generation, which runs at high capacity factors.

Figure 20 **NEM plant retirements and new entry between 2011 and 2020 by region (MW) - 10% case**

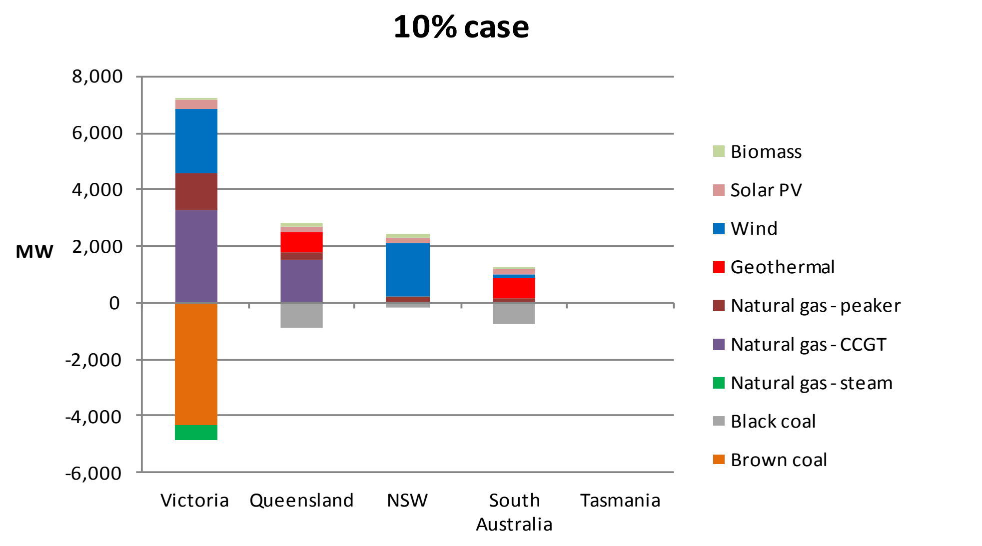


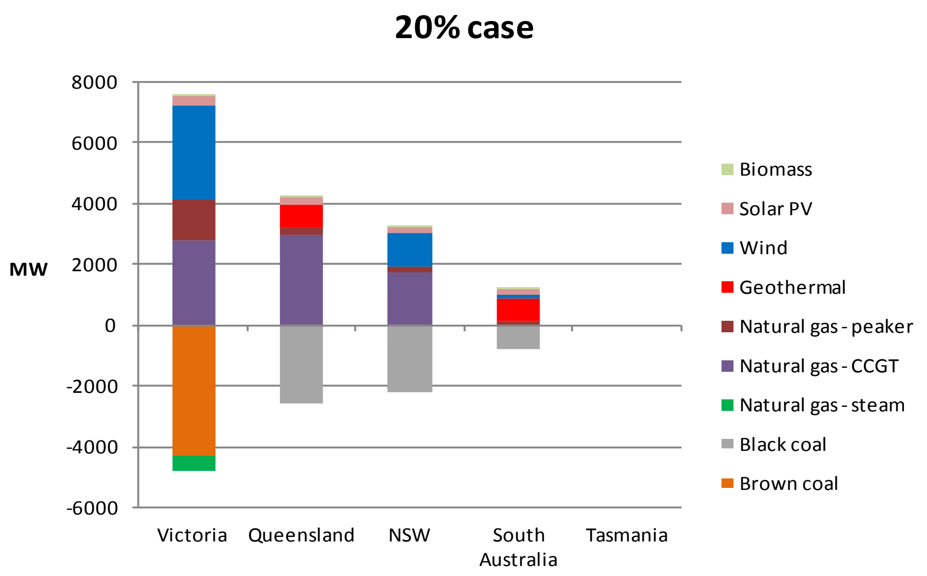
Table 30 **NEM plant retirements and new entry between 2011 and 2020 (MW) - 20% case**

	NSW	Vic	Qld	SA	Tas	NEM
			Retirements			
Brown coal		4,335				4,335
Black coal	2,250		2,570	770		5,590
Natural gas steam		500				500
TOTAL	2,250	4,835	2,570	770		10,425
			New Entry			
CCGT	1,750	2,800	3,000	0	0	7,550
OCGT	200	1,340	250	150	0	1,940
Biomass	85	57	114	28	0	284
Solar	200	320	200	200	0	920
Wind	1,086	3,089	0	103	0	4,278
Geothermal	0	0	750	750	0	1,500
Coal	0	0	0	0	0	0
Total	3,321	7,606	4,314	1,231	0	16,472

Data source: ACIL Tasman modelling

Note: This table shows only replacement generation from 2011 to 2020.

Figure 21 **NEM plant retirements and new entry between 2011 and 2020 by region (MW) - 20% case**



Data source: ACIL Tasman modelling

Note: Wind capacities in NSW and Victoria differ between the 10% and 20% cases as a result of the different new entry schedules used in the two cases and the need to balance load and capacity growth. Total NEM wind capacity is the same in the two cases.

In the 20% case the additional withdrawals needed to achieve the higher target came from black coal generators. The lower emissions were achieved by the withdrawal of Gladstone in Queensland and Liddell in NSW. Loy Yang A remained generating in this simulation (its net revenue was low but positive).

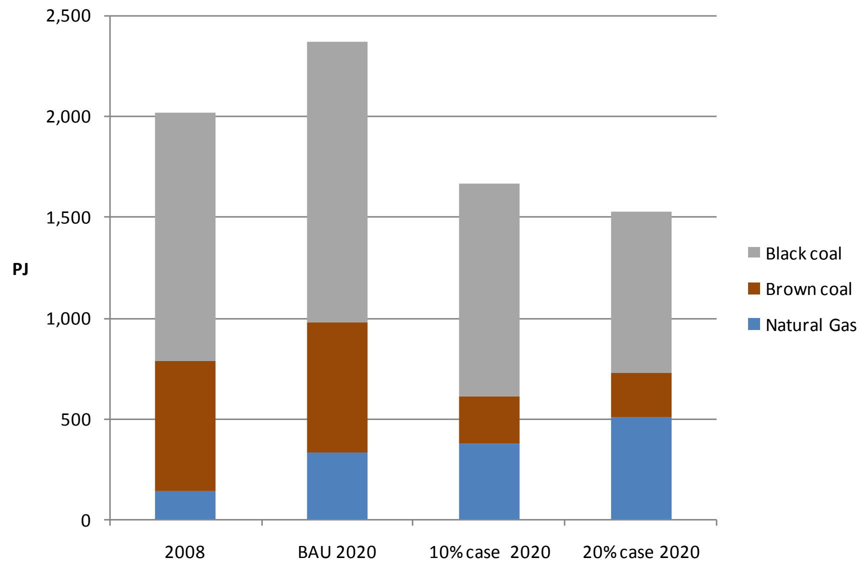
Table 31 **NEM cumulative capital expenditure on new plant ($2008 $million), including renewable component**

	BAU		10% case		20% case	
NEM	Total	Renewable (incl in total)	Total	Renewable (incl in total)	Total	Renewable (incl in total)
2011	$342	$342	$1,755	$1,755	$1,755	$1,755
2012	$972	$342	$4,401	$4,360	$4,401	$4,360
2013	$2,207	$342	$7,243	$6,710	$7,243	$6,710
2014	$3,219	$342	$10,011	$9,079	$12,108	$9,079
2015	$4,166	$342	$13,079	$11,414	$14,736	$11,414
2016	$5,206	$342	$16,638	$14,589	$18,295	$14,589
2017	$5,872	$342	$20,439	$16,958	$21,189	$16,958
2018	$7,380	$342	$23,335	$19,177	$24,964	$19,177
2019	$8,848	$342	$26,636	$21,277	$28,322	$21,277
2020	$10,791	$342	$30,300	$23,282	$33,514	$23,282

Data source: ACIL Tasman modelling

Table 31 shows the capital cost of new plant entering the market under the 3 scenarios (BAU, 10% and 20% emissions reductions). These capital costs cover the generating plant only and do not include additional network costs in the form of transmission lines to connect new wind and geothermal generation to the network and new and expanded gas pipelines to deliver the substantial increase in gas used for electricity generation.

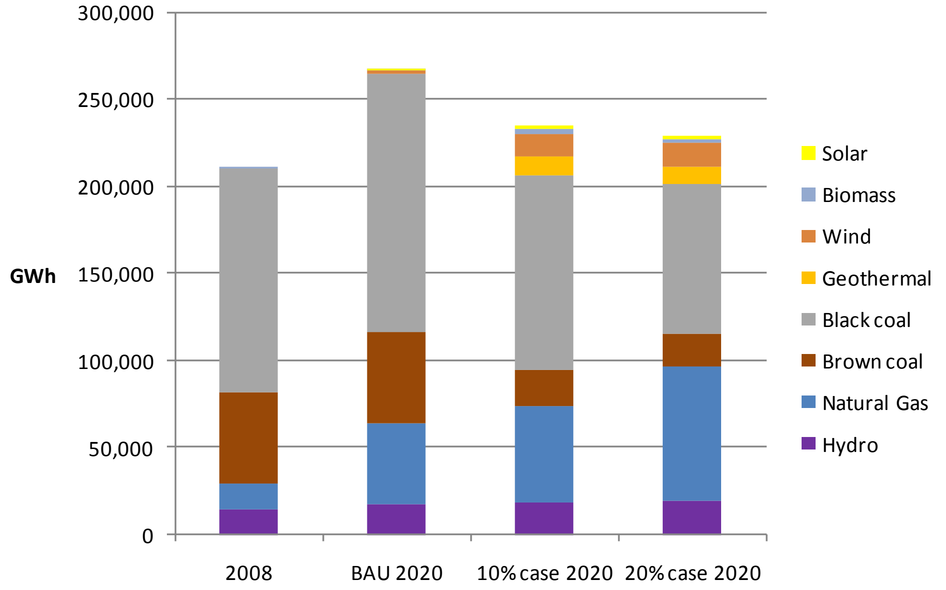
Figure 22 **Fuel consumption in the NEM, 2008 and 2020 (PJ)**



Data source: ACIL Tasman modelling

Figure 22 shows the fuel used in the NEM in 2008 compared to the modelled 2020 year for the BAU, 10% and 20% cases. Fuel consumption reduces under both the 10% and 20% cases as coal fired power is replaced by renewable sources such as wind and geothermal energy and natural gas, which is used in CCGTs with a much higher efficiency than the brown coal it is largely replacing.

Figure 23 **NEM generation by type (GWh) – BAU, 10% and 20% cases**

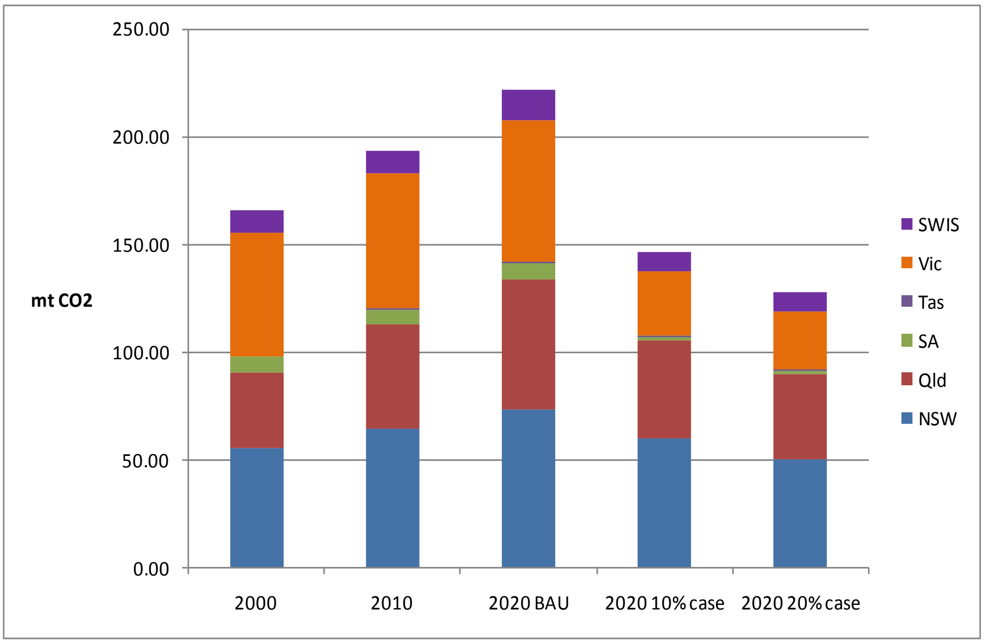


Data source: ACIL Tasman modelling

Figure 23 shows the generation in GWh in the NEM in 2008 and in 2020 in the BAU, 10% and 20% cases. This includes only that generation which is scheduled to generate in the NEM, renewable generation outside the NEM is excluded. Renewables provide up to the MRET target under the incentives from the RECs. If more savings are required (by moving from the 10 to the 20% case) then the lowest cost form of generation is used, which is electricity generated in a CCGT from natural gas. As black coal is backed out of the market to meet the 20% target, falling from 48% to 37% of energy generated, gas increases to make up the difference, from 23% to 33%.

Figure 24 shows the total emissions for each jurisdiction in the NEM and SWIS for 2000, 2010, and 2020 BAU, 10% and 20% cases.

Figure 24 **CO_2 emissions - BAU, 10% and 20% cases**



Data source: ACIL Tasman modelling

8.2 An indicator of the effect on asset values

In carrying out the simulations of the NEM and the SWIS ACIL Tasman has calculated the net return per kW of capacity for each power station in order to provide an indicator as to whether a particular power station will exit the market or keep generating. The calculation of net revenue per kW involved taking each power station's revenue from the pool, subtracting fuel and material costs, emission permit costs as well as variable and fixed operation and maintenance costs. This parameter represents the amount left to pay capital after short run costs and overheads have been deducted but before tax and finance charges.

As a return to capital it also represents a value of the asset and as this number varies with the application of an ETS it can provide an indicator of the variation in asset values resulting from alternative scenarios. A typical commercial approach to valuing an asset involves taking the present value of its estimated future net cash flows. In this case the only period over which cash flows can be aggregated and discounted is 2010 to 2020. Variations in asset value arising from changes in cash flows after 2020 are not included. The present value of net revenue per kW of capacity only provides an *indicator* of asset value as it does not take into account different approaches to financing, tax payments or deductions, the age of assets and future expenditures required for refurbishment.

As a consistent approach is applied to calculating the indicator in each of the 3 scenarios it is the difference in the returns between the scenarios that provides the most useful indication of the impact of an ETS on asset values rather than the absolute value of the number.

The cost of a new kW of capacity for each of the generation technologies shown varies considerably. Brown coal plant is the most expensive, followed by black coal. Hydro plant can be high cost per kW, depending on the site. The capital cost of a CCGT is probably the lowest for base load or intermediate generation and OCGT peaking plant is usually the least expensive of all conventional technologies. The returns required per kW will vary between the different technologies.

Table 32 below shows the average of the present values of net revenue per kW for a range of asset classes in the NEM. The real ($2008) annual net revenues per kW for each power station included have been discounted at 5.5% pa discount rate to arrive at a present value for the 10 year period.

Victorian and South Australian coal fired power stations have been grouped together and NSW coal fired power stations have been grouped as have Queensland coal fired generators.

Table 32 **Present value of net revenue per kW for certain asset classes in the NEM, 2010 to 2020 ($2008)**

Asset Class	BAU	10%	20%
Victorian and SA coal	1803	302	139
NSW coal	1052	222	84
Queensland coal	913	191	40
CCGT	621	381	339
OCGT	333	92	55
Hydro	467	568	652

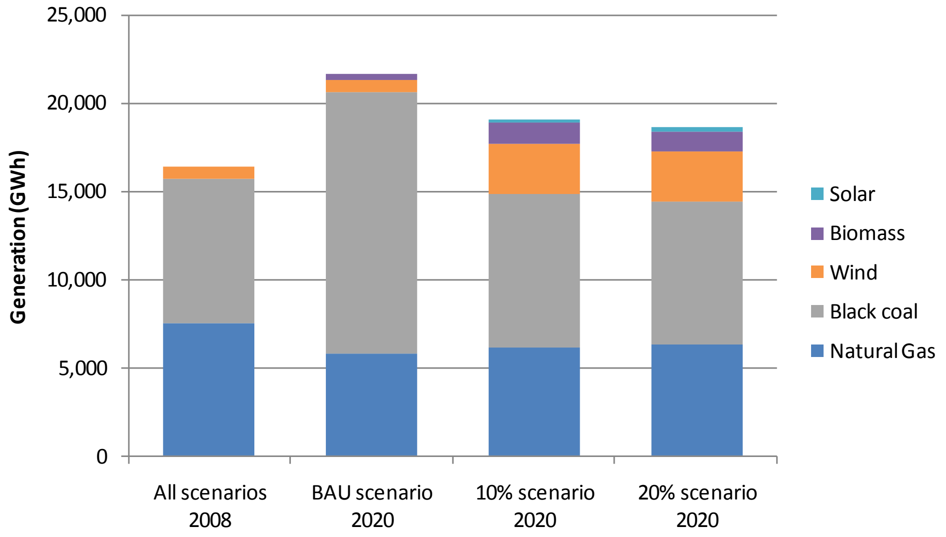
The only asset class that appears to improve in value between the BAU and the ETS cases is hydro, which is the only zero emission technology included in the table (other zero emission technologies such as geothermal and wind energy are not included as they are not in the BAU case). Gas fired CCGTs and OCGTs decline somewhat, mainly because of the increase in the price of gas for electricity generation that is projected in the ETS scenarios.

8.3 SWIS results

The modelling of the SWIS assumes the same carbon price path and similar demand reduction responses as for the NEM modelling. 10%, 20% and BAU scenarios were also modelled.

Figure 25 shows generation by fuel type for 2008 (all scenarios) and for 2020 for the BAU, 10% and 20% cases.

Figure 25 **SWIS - generation by fuel type, 2008 and 2020 - BAU, 10% and 20% cases**



Data source: ACIL Tasman's PowerMark modelling

Gas generation declines in the SWIS as new generation is currently expected to be from new coal fired plants in the BAU. In the two ETS scenarios (the 10% and 20% cases) coal fired generation falls by about one third compared to the BAU. This expected fall in generation from coal makes up nearly all the emissions savings in WA. It is replaced mainly by new wind generation and from demand reductions brought about by higher prices.

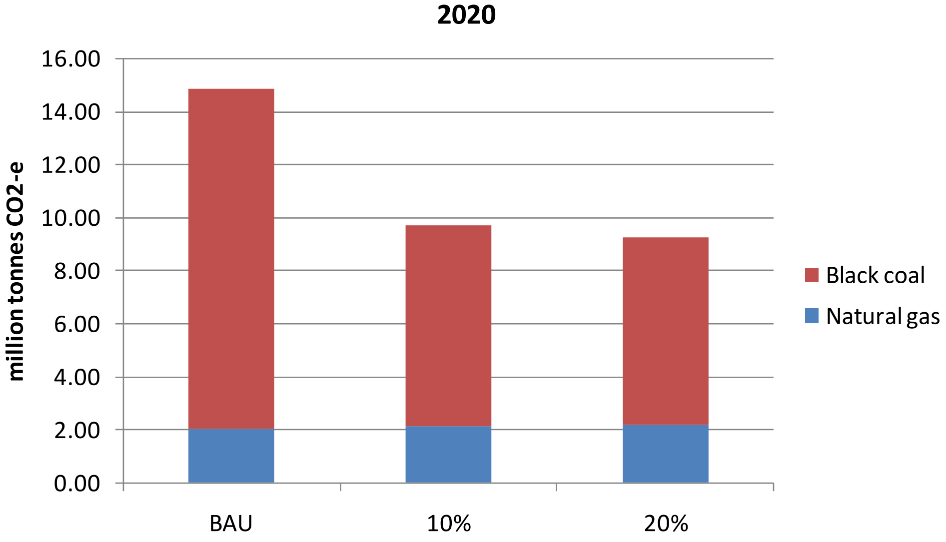
Figure 26 shows emissions by fuel type in the BAU, 10% and 20% scenarios in 2020. In 2020, total emissions are an estimated 9.74 million tonnes and 9.27 million tonnes in the 10% and 20% cases, respectively.

This represents a 1% decrease on 2000 levels in the 10% case and a 6% decrease on 2000 levels in the 20% case.[6]

[6] This emissions reduction assumes emissions of 9.86 million tonnes of CO_2-e in the year 2000.

BAU emissions are 14.92 million tonnes of CO_2-e in 2020, more than 50% greater than the 10% and 20% cases in 2020, primarily because the BAU assumes a significant volume of new coal fired plant that does not proceed under an ETS.

Figure 26 **Emissions, by fuel type (million tonnes CO_2-e) - 2020**



Data source: ACIL Tasman's *PowerMark* modelling

Table 33 shows new entrants between 2011 and 2020 in all scenarios. No plant was retired during this period, in any of the scenarios.

In the 10% and 20% scenarios, there are no new entrant black coal and natural gas CCGTs after 2011. This is partially due to reduced load from the price response, and also due to 860MW of new entrant renewable generation between 2011 and 2020, which has been introduced to satisfy the 20% RET by 2020.

In the BAU, in which there is no ETS and no renewables target, the lowest cost new entrant is black coal. In this case there is 600MW of new entry black coal plant between 2011 and 2020.

Table 33 **SWIS new entrants between 2011 and 2020 (MW) – BAU, 10% and 20% cases**

New entrants (MW)	BAU	10% scenario	20% scenario
Black coal	600	-	-
Natural gas - peaking	1,050	400	300
Wind	-	600	600
Biomass	-	100	100
Solar PV	-	160	160
Total	1,650	1,260	1,160

Table 34 **SWIS capital expenditure on new plant between 2011 and 2020 ($2008 million)**

New entrants (MW)	BAU	10% scenario	20% scenario
Black coal	$1,183	-	-
Natural gas - peaking	$1,035	$394	$296
Wind	-	$1,476	$1,476
Biomass	-	$220	$220
Solar PV	-	$1,015	$1,015
Total	$2,270	$3,105	$3,006

8.4 The costs of emissions savings in electricity markets

An ETS is intended to give the market the ability to find the cheapest emissions savings while still delivering the product to consumers at the lowest cost. With electricity generation clearly the lowest cost savings will come from savings that consumers make without there being any increase in electricity prices. These are savings resulting from conservation programs such as the Mandatory Energy Performance Standards (MEPS) aimed at educating consumers to make savings that lower their electricity costs without any detrimental effects on the consumers themselves. Such savings have a negative cost (a benefit) in that they reduce emissions and increase consumers' disposable income without reducing the service (or welfare) they gain from their electricity consumption.

Other low cost savings are almost certainly available from forestry and other agriculture offsets sales sourced both within Australia and overseas.

The volumes of these savings are very difficult to estimate at present as in many respects it depends upon the way an ETS is administered and the willingness of the scheme's administrators to accept and authenticate Australian and overseas large scale sequestration. Our initial review of forestry in Australia indicates an additional 25 million tonnes CO_2–e offset sales could be available at the emissions permit prices being estimated in this report. Another 25 million tonnes CO_2–e offsets, sourced within Australia or overseas, would begin to reduce the burden on the stationary energy sector and reduce the price of emissions permits.

Probably the most expensive emissions savings are those based on substituting existing electricity generation with lower emission technology. In this case consumers see the same level of service but the generation technology has lower emission intensity. We have estimated this cost by comparing the LRMC of the technology in question with the LRMC of the existing base load technology that is being replaced or backed out of the market. This is a marginal analysis, comparing the cost of an additional MWh of generation from the low cost source in which emissions are unpriced with a higher cost but lower (or zero) emissions source. The difference in the cost of generation is the additional cost being borne in order to reduce emissions.

For example, if the lowest cost new entrant in 2010 (in a market where emissions are unpriced) would be a super critical coal fired power station with a LRMC of $44/MWh and an emissions intensity of 0.75 tonnes CO_2–e /MWh and this is compared with a gas fired new entrant at a LRMC of $60/MWh and an emissions intensity of 0.4 tonnes CO_2–e /MWh, the cost of emissions abatement in this case is estimated at about $46/tonne CO_2–e. This is the additional cost incurred by electricity consumers in consuming an alternative lower emission generation technology/tonne of CO_2–e saved.

This approach to pricing emissions is sound in theory (the additional cost of a substitute is taken as the cost of emissions abatement) but runs up against some obstacles in practice. For example, the lowest cost new entrant and the emissions intensity of the generation fleet will vary from region to region. In this case the marginal cost of emissions abatement is varying between regions, as would be expected and as can be seen from the results of this project. Pricing emissions has very different effects in different regions. Also, not all new energy generation technologies replace a base load coal fired power station. Some, such as solar thermal and solar PVs for example, have variable output and would displace both base and peaking power generation intermittently.

Table 35 **Cost of emissions saved by substitution, Victoria, NSW and Queensland in 2010 ($2008)**

	LRMC $/MWh	Emissions tonnes CO_2–e /MWh	Cost of emissions saved ($/tonne CO_2–e)
Victoria			
Coal fired plant (brown coal)	46	1.2	
Gas fired CCGT	54	0.4	10
Wind turbine	100	0	45
Solar thermal	200	0	128
Solar PV	240	0	162
NSW and Queensland			
Coal fired plant (black coal)	44	0.75	
Gas fired CCGT	60	0.40	46
Wind turbine	100	0	75
Solar thermal	200	0	208
Solar PV	240	0	261

Data source: ACIL Tasman modelling

Note: Victorian CCGT has lower LRMC due to lower gas price.

The LRMCs in Table 35 are estimates of these costs in 2010. It is very likely that the costs of renewables will fall over the coming decade and solar thermal and solar PV generation reach between $100 and $150/MWh. In this case the cost of emissions saved would be $66 to $133/tonne CO_2–e.

8.5 The effects of an ETS in 2020

The major effects of the ETS as modelled in this study are:

Prices

- With a 10% target emission prices reach $45/tonne CO_2–e in real terms and $57.50/tonne CO_2–e in nominal terms by 2020. With a 20% target emission prices reach $55/tonne CO_2–e in real terms and $67/tonne CO_2–e in nominal terms.
- Regional reference prices (in nominal prices) in the NEM are $97 to $109/MWh in the 10% case while in the 20% case they are $98 to $122/MWh.
- In real terms the RRPs range from $70 to $79/MWh in the 10% case and $71.50 to $88/MWh in the 20% case. Queensland, NSW, South Australian and Victorian prices are within a few dollars while Tasmanian prices are the lowest.

Changes in capacity

In the NEM and SWIS:

- New generation capacity to replace retiring brown coal and some black coal plant will need a significant building effort. The modelling indicates that the 10% case will cause the retirement of 6,145MW of mostly brown and some black coal plant in the NEM. We have also assumed the retirement of an older steam gas-fired plant of 500MW in Victoria. There are no projected closures in the SWIS.
- In the 10% case these retirements would be replaced by 13,672MW of gas fired and renewables plant in the NEM. In the SWIS there are no retirements and 1,260MW of new plant is required.
- In the 20% case we have retired 10,425MW of coal fired and steam plant and replaced it with 16,472MW of gas-fired and renewable plant in the NEM. In the SWIS there are no retirements and 1,160MW of new plant is required.
- The capacity of new plant in the NEM is about 205% of that being retired in the 10% case and approximately 160% in the 20% case. This is partly to cope with some level of growth in demand, although growth in energy demand in both cases is low given the effects of conservation measures, demand response to higher prices and the use of distributed renewables, but mainly because much of the new plant is renewable generation with a relatively low capacity factor (less than 35%) and more capacity is required to produce the same amount of energy.

The value of existing assets

- Using the net present value of returns per kW over the 10 years 2010 to 2020, the average of this indicator for Victorian and South Australian coal fired generation indicated a fall of over 80% in asset value in the 10% case and over 90% in the 20% case.
- For NSW coal generation the corresponding falls were under 80% and about 90% and Queensland coal fired generation assets also reduced by 80% and almost 95%.
- Gas fired CCGTs on average reduced in value by about 40% in the 10% case and about 45% in the 20% case, largely because of the increase in the costs of gas for generation. The average asset value of gas fired OCGTs reduced in value by 70% and about 80% respectively.
- The only asset value to increase in value between the BAU and the ETS cases was hydro, and this was by 20% and 40% respectively. The comparison between the BAU and ETS cases was not possible for other zero emission technologies, such as geothermal and wind, as they were not included in the BAU case but it is highly likely that an ETS would increase the asset values in these technologies as well.

Capital expenditure

- In the 10% case we estimate the cost of investment in generation in 2008 prices at $30.3 billion in the NEM and $3.1 billion in the SWIS.
- In the 20% case we estimate the cost of investment in generation in 2008 prices at $33.5 billion in the NEM and $3.0 billion in the SWIS.
- These estimates of capital expenditure do not include the costs of expanding the electricity transmission network in order to connect geothermal and wind generation in remote locations or the cost of expanding the gas supply network. We estimate that approximately $4 billion would be required to enhance the transmission network to include this new plant and at least $0.5 billion in new pipeline investment to carry additional gas to power stations.

A Electricity market modelling assumptions

A.1 The standard year of hourly loads

For the scenarios ACIL Tasman's PowerMark model simulates the NEM on an hourly basis (that is, it uses hourly settlement periods) – therefore, a set of hourly loads for each region is required for each year of the projection.

PowerMark can actually simulate the market on a half-hourly basis and therefore the process described below in fact creates a set of standard half hourly loads. However, for the scenarios, the first half hour of each hour is modelled. Our experience is that modelling on a half hourly basis is not warranted for a 10-year scenario type projection – the slight increase in data richness is more than offset by the doubling of model run time. Typically, PowerMark is run on a half-hourly basis for more detailed, short-term analysis (such as assessing the impact on revenue of a unit outage for insurance purposes).

It is possible to use as a basis the set of actual hourly loads for any of the past recent years and then grow this set of loads to the winter/summer peak demands and annual energy provided in the NEMMCO SOO. However, it is well recognised that load is affected by weather and therefore the risk of using this approach is the assumption that the weather of the past few years is typical and will continue into the future.

Instead of making this assumption, the approach used in creating a set of hourly loads attempts to remove atypical weather effects to produce a load profile that could be expected given a typical weather pattern.

The simulated hourly load profile for each region is based on actual half-hour generated load observations for the four years 2002/03 to 2005/06 and temperature and humidity data for 1970/71 to 2005/06.

A summary of the process used to create a standard set of hourly loads is described in the following box.

Box A1 **Process for constructing a standard set of hourly loads**

Step 1 - The actual hourly loads from 2002/2003 to 2005/06 are grown to 2005/06 levels by modelling a general level of growth across the four years on a quarterly basis. This has the outcome of accounting for economic growth over the past four years but does not remove the impact of weather on the loads. In a sense, four sets of loads are produced for 2005/06 accounting for each of the annual weather patterns of the past four years.

Step 2 – At the completion of Step 1, there exists 36 years worth of weather data and 4 years worth of load data, which overlap in terms of time. The purpose of Step 2 is to create 36 sets of load data – one for each of the 36 'weather years'. The hourly load profile for each day for each weather year is selected from the four load data years with the closest matching temperature conditions (as well as accounting for day type and season). This is achieved by finding the closest least squares match between the temperature profile for that day and the temperature profile for a day in one of the four load data years.

Step 3 – At the completion of Step 3, there exists 36 sets of annual hourly load data. Each set differs and this difference is directly related to the weather conditions associated with each set. The purpose of Step 3 is to create a single representative combination of the 36 sets of loads – referred to as the 'standard year of loads'. If there existed only one region then an approach to ensure that the standard year of loads represented the 36 sets of loads would be to choose the median set of hourly loads for each day of the year. However, because there a multiple regions and we wish to preserve the correlation between regional loads another approach is required. This is achieved by randomly choosing one of the 36 load sets for each day of the standard year.

Step 4 – At the completion of Step 4, there exists, for each region, a single set of hourly load data – representing the standard year of loads. Given that a random number generator is used to construct this set of loads there is no guarantee that the resulting set of loads is indeed representative of the 36 sets. Therefore, the purpose of Step 4 is to ensure that the standard year of loads is representative. This is done using a number of summary statistics and graphs.

Step 3 and 4 are repeated until a reasonably representative set of loads is selected.

The standard year of simulated hourly loads is then scaled for each year of the projection based on the projected winter and summer peak demands and annual energy. Technically, a non-linear transformation method is used to ensure all hourly data conform to both the annual energy and the winter and summer peak loads.

The outcome of this process is a set of loads that could be expected given typical weather conditions. In other words, the short-term stochastic influences of weather on load have been removed. This is an important step in the scenario development process - as variation in load profile due to weather does have a significant impact on the projection results.

This process is used for the four mainland regions. Unfortunately, ACIL Tasman does not have access to sufficient historical load data for Tasmania to utilise this approach. In the case of Tasmania, a single set of historical hourly load data is scaled to the winter/summer peak load and annual energy parameters.

This matching approach removes the often contentious obstacle of attempting to derive mathematical formulas to quantify the relationship between load and temperature.

A.2 New entrant costs

A.2.1 Project capital costs

Project capital costs for a new power station include:

- engineering, procurement and construction (EPC)
- planning and approval
- professional services
- land acquisition
- infrastructure costs (incl. water)
- spares and workshop etc
- network connection
- fuel connection, handling, storage
- mine development and infrastructure for coal fired developments.

Capital costs are usually expressed in $/kW.

ACIL Tasman estimates the project capital cost of a CCGT in the NEM to be $1,200/kW for 2008, this is quite an increase from our 2007 estimate of 1,050/kW. Over the past 12 months there have been a small number of projects in Australia and New Zealand and it is quite apparent that capital costs have continued to increase. This trend is supported by data from other countries and sources and reflects the continued increasing demand for turbines.

It is difficult to predict with any certainty whether the project capital costs have peaked. Most feedback we get from various clients in the industry, local and overseas, suggests the expectation is that given the continued backlog of turbine orders, increasing material costs and labour costs, project capital costs could well continue to increase at the rates we have observed over the past two to three years. However, we have no quantitative basis for making such an assertion and therefore err on what we think is the conservative side and assume no further step changes in capital costs.

Analysis of our database of international CCGT projects suggests that project capital costs have historically increased on average at a rate of 80% of CPI. This appears to broadly agree with Cottrell et al's (2003) estimate of -0.5% for the annual 'learning rate' for CCGT plant which implies that the cost of CCGT projects will decrease in real terms by 0.5%/year (assuming an inflation rate of 2.5%).

On this basis, assuming capital costs have peaked, our 10-year projection of project capital costs for a new build CCGT are presented in Table A1.

Table A1 **Project capital cost ($/kW) for CCGT**

Year ending June	Nominal $/kW	Real (2007-08) $/kW
2008	$1,200	$1,200
2009	$1,224	$1,194
2010	$1,248	$1,188
2011	$1,273	$1,183
2012	$1,299	$1,177
2013	$1,325	$1,171
2014	$1,351	$1,165
2015	$1,378	$1,160
2016	$1,406	$1,154
2017	$1,434	$1,148

Data source: ACIL Tasman analysis

A.2.2 Black coal fired plant

ACIL Tasman estimates that the project capital cost of a coal-fired plant in the NEM to be $1,900/kW for 2008. Coal fired plant capital costs have also increased in a similar manner to CCGTs over the past 12 months.

Our 10-year projection of project capital costs for a new build super-critical coal-fired are presented in Table A2.

Table A2 **Project capital cost ($/kW) for supercritical black coal**

Year ending June	Nominal $/kW	Real (2007-08) $/kW
2008	$1,900	$1,900
2009	$1,938	$1,891
2010	$1,977	$1,882
2011	$2,016	$1,872
2012	$2,057	$1,863
2013	$2,098	$1,854
2014	$2,140	$1,845
2015	$2,183	$1,836
2016	$2,226	$1,827
2017	$2,271	$1,818

Data source: ACIL Tasman analysis

A.2.3 Brown coal fired plant

As in the 2007 generator cost report to NEMMCO, $200/kW has been assumed as the additional project capital costs for a brown coal fired new entrant project to account for additional coal handing requirements etc. This means that the project capital cost for brown coal fired plant in the NEM would be around $2,250/kW for 2008. This cost assumes access to third party coal.

Table A3 provides a 10 year projection of project capital costs for a brown coal fired plant.

Table A3 **Project capital cost ($/kW) for supercritical brown coal**

Year ending June	Nominal $/kW	Real (2007-08) $/kW
2008	$2,250	$2,250
2009	$2,295	$2,239
2010	$2,341	$2,228
2011	$2,388	$2,217
2012	$2,435	$2,206
2013	$2,484	$2,196
2014	$2,534	$2,185
2015	$2,585	$2,174
2016	$2,636	$2,164
2017	$2,689	$2,153

Data source: ACIL Tasman analysis

A.2.4 OCGT

ACIL Tasman estimate the project capital cost for an OCGT plant in the NEM to be $850/kW for 2008.

Assuming that the project capital cost of an OCGT escalates at 80% of CPI (the same rate as the CCGT and coal fired plant), then a 10-year projection of project capital costs for a new OCGT would be as presented in Table A4.

Table A4 **Project capital cost ($/kW) for OCGT**

Calendar year	Nominal $/kW	Real (2008) $/kW
2008	$850	$850
2009	$867	$846
2010	$884	$842
2011	$902	$838
2012	$920	$834
2013	$938	$829
2014	$957	$825
2015	$976	$821
2016	$996	$817
2017	$1,016	$813

Data source: ACIL Tasman analysis

A.2.5 Fixed O&M costs

Fixed O&M costs include maintenance, operating, and overhead costs that are not dependent on the hour-by-hour level of generation from the station.

ACIL Tasman's estimates of fixed O&M costs are provided in Table A5. Our view on the fixed costs for the existing technologies has evolved over time and has been subjected to review from a large number of clients. Our estimates of fixed O&M also take into account our analysis of annual reports of power generation companies.

Table A5 **Estimated fixed O&M cost in 2007-08 and escalation rate**

Technology	$/MW/year	Escalation rate (% of CPI)
CCGT	$12,800	100%
Supercritical – black coal	$40,000	100%
Supercritical – brown coal	$40,000	100%
OCGT	$7,500	100%

Data source: ACIL Tasman and analysis

A.2.6 Variable O&M costs

ACIL Tasman's estimates of variable O&M costs are provided in Table A6. The estimates for variable costs for the existing technologies has evolved over time and incorporates analysis of NEM offer curves to deconstruct the SRMC cost components. Our estimates have been subjected to review from a large number of clients.

Table A6 **Variable O&M cost in 2007-08 and escalation rate**

Technology	$/MWh	Escalation rate (% of CPI)
CCGT	$4.85	100%
Supercritical – black coal	$1.20	100%
Supercritical – brown coal	$1.20	100%
OCGT	$7.50	100%

Data source: ACIL Tasman and analysis

A.2.7 Auxiliaries

ACIL Tasman's estimates of auxiliaries are provided in Table A7. The estimates have been based on published sent-out and generated output by existing NEM generators feedback from clients.

Table A7 **Auxiliaries usage (%) for new entrants**

Technology	Auxiliaries usage
CCGT	2.4%
Supercritical – black coal	7.5%
Supercritical – brown coal	9.5%
OCGT	2.0%

Data source: ACIL Tasman and analysis

A.2.8 Thermal efficiency

ACIL Tasman's estimates of thermal efficiency are provided in Table A8. Our view on the thermal efficiency for the existing technologies has evolved over time and includes analysis of offer curves of existing plant to deconstruct the SRMC cost components. The estimates have been subjected to review from a large number of clients.

Table A8 **Thermal efficiency (HHV, as sent out) for new entrants**

Technology	Efficiency
CCGT	52%
Supercritical – black coal	42%
Supercritical – brown coal	34%
OCGT	31%

Data source: ACIL Tasman and analysis

A.2.9 Discount factor (WACC)

The discount factor (or WACC) is derived using the components shown in Table A9.

Table A9 **WACC components**

Component	Symbol
Inflation	F
Corporate tax rate (effective)	T
Liability	V
Debt	D
Equity	E
Risk free Rate	RF
Market Return	RM
Market risk premium	MRP
Cost of debt	RD
Gamma	G
Asset Beta	BA
Debt Beta	BD
Equity Beta	BE
Expected return on equity	RE

Data source: ACIL Tasman and analysis

The post-tax real and nominal WACCs have been estimated using the following formulas:

$$WACC_{\text{post-tax real}} = \left(\frac{(1 + WACC_{\text{post-tax nominal}})}{(1 - F)} \right) - 1$$

where:

$$WACC_{\text{post-tax nominal}} = RE \left(\frac{(1-T)}{(1 - T(1-G))} \right) \times \frac{E}{V} + RD(1-T) \times \frac{D}{V}$$

and:

$$RE = RF + BE \;\; RM - RF$$

ACIL Tasman's estimates of the WACC components are provided in Table A10. There has been little change in ACIL Tasman's estimated WACC over time. The two changes have been with regard to the updating of the risk free rate to reflect the past six months' performance of the 10-year T- Bonds and a slight increase in the debt basis premium to reflect feedback received over the past 12 months from various banks, that have engaged ACIL Tasman either directly or indirectly, in relation to potential new build projects.

It is difficult to provide a comparison from other sources for the entire set of WACC components – most regulatory decisions for retail electricity prices, which usually include details of the WACC assumptions, are now based on short-term market projections rather than calculating the LRMC of a new entrant plant from first principles – the 2004 ESIPC report appears to be the last example of this. The WACC estimates are regularly scrutinised by clients including Banks during market due diligence for existing and potential market participants.

Table A10 **Calculation of WACC**

Component	Assumed/calculated value
Debt	60%
Equity	40%
Risk free RoR	5.70%
Market risk premium	6.00%
Market RoR	11.70%
Corporate tax rate	30%
Effective tax rate	22.5%
Debt basis point premium	200
Cost of debt	7.70%
Gamma	0.50
Asset Beta	0.80
Debt Beta	0.16
Equity Beta	1.75
Required return on equity	16.21%
Inflation	2.50%
Post-tax nominal WACC	9.25%
Post-tax real WACC	6.58%
Pre-tax nominal WACC	11.93%
Pre-tax real WACC	9.20%

Data source: ACIL Tasman and analysis

A.2.10 Build time and project life

For the purpose of calculating the long run marginal cost of a new plant a project life of 30 years has been assumed. The build time assumed for each type of technology is shown in Table A11.

Table A11 **Construction profile (% of project capital cost)**

Technology	Year -4	Year -3	Year -2	Year -1
CCGT	0%	0%	40%	60%
Supercritical – black coal	10%	20%	35%	35%
Supercritical – brown coal	10%	20%	35%	35%
OCGT	0%	0%	0%	100%

Data source: ACIL Tasman and analysis

A.2.11 Summary of new entrant costs

Table A12 provides estimates of the annualised fixed costs (capital and fixed O&M) of greenfield generation projects in the NEM. The numbers are based on a discounted cash flow (DCF) model using the long run marginal cost input assumptions presented in this chapter. The values presented are the fixed costs/kW of installed capacity per year.

Based on the information available, it seems reasonable to assume that emerging technologies (such as coal plant with carbon, capture and storage) are unlikely to be commercially available before 2020 with demonstration projects potentially operating from 2015 onwards.

Table A12 **Annualised capital and fixed O&M costs (nominal $/kW/year)**

Year ending June that plant is installed	CCGT	Black coal	Brown coal	OCGT
2008	$126	$226	$257	$85
2009	$128	$231	$262	$87
2010	$131	$236	$267	$89
2011	$133	$241	$273	$91
2012	$136	$246	$279	$92
2013	$139	$251	$284	$94
2014	$142	$256	$290	$96
2015	$145	$262	$296	$98
2016	$148	$267	$302	$100
2017	$151	$273	$309	$102

Note: These values represent the annualised project capital plus fixed O&M costs required to be recovered each year.
Data source: ACIL Tasman analysis

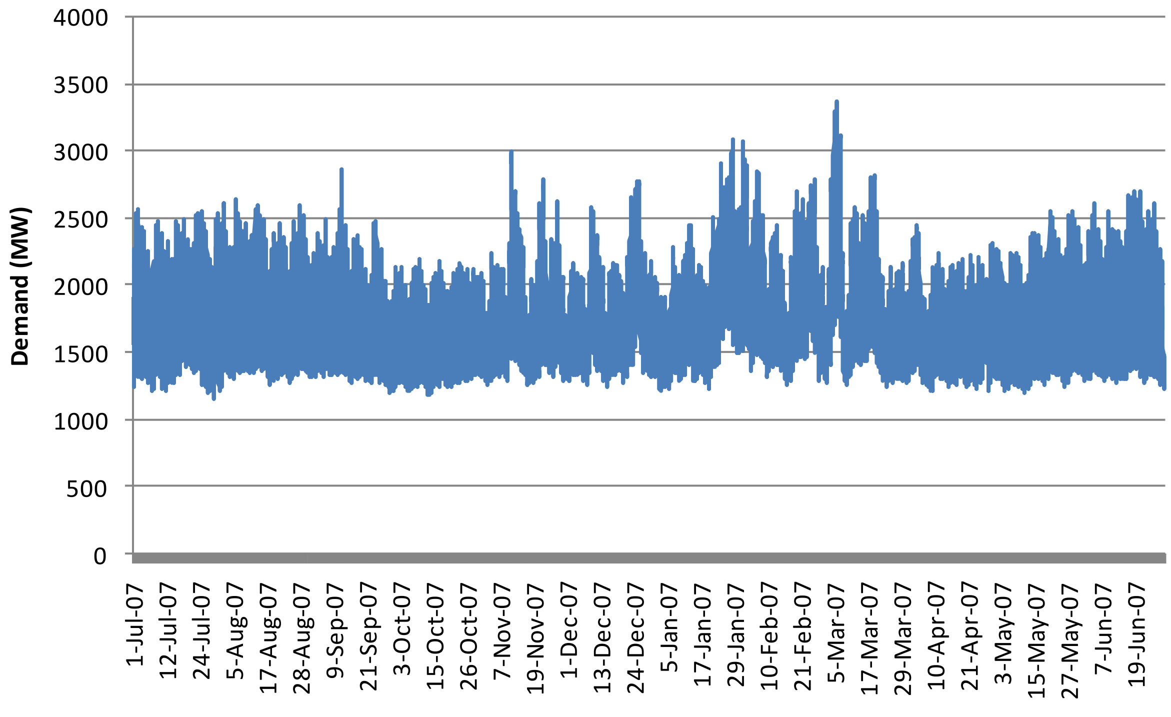
A.3 Assumptions for the SWIS

A.3.1 The standard year of hourly loads

ACIL Tasman's *WA PowerMark* model simulates the SWIS for each half-hour period and requires a forecast half hourly load trace for the entire modelling period.

ACIL Tasman has made the assumption that the half hourly load trace for 2007 is a reasonable representation of the typical load trace for the SWIS. Of course, given the nature of weather and demand it is virtually impossible to choose a representative year of loads based on historical data. Each year in the past will invariably have its own peculiarity.

Figure A1 **SWIS load trace for calendar year 2007**



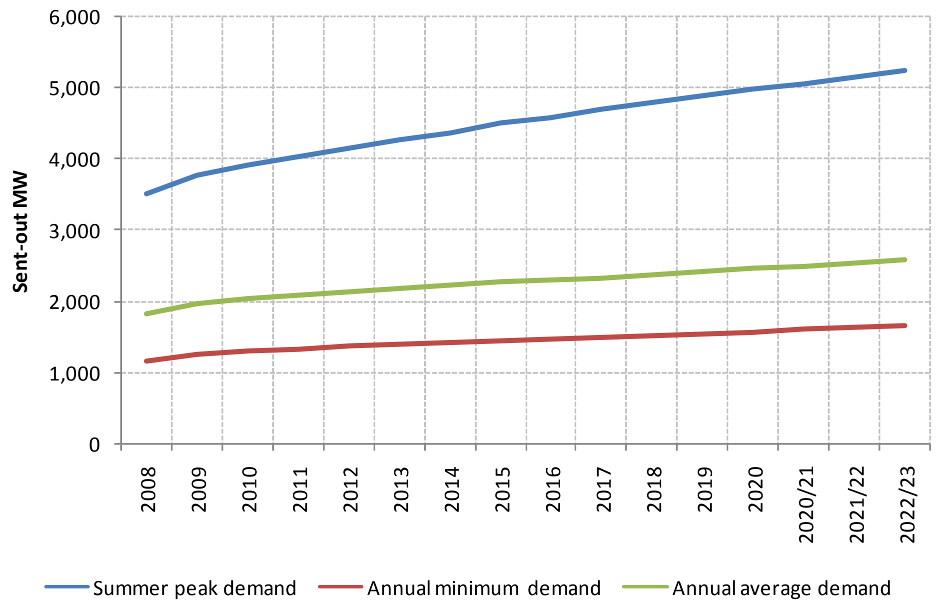
Data source: ACIL Tasman

The base year of simulated half hourly loads is scaled for each year of the projection based on the forecast annual peak, average and minimum loads. Technically, a non-linear transformation method is used to ensure all hourly data conform to both the annual energy and the summer peak and overnight minimum loads.

A.3.2 Load forecast

For the BAU case, the 2007 SWIS load forecast as published by the IMO was used and is shown in Table A13 and Figure A2. The response to higher prices under the 10% and 20% cases reduces BAU load in 2020 by 12% and 14%, respectively.[7]

Figure A2 **BAU load forecast 2008-2020**



Data source: IMO

Table A13 **BAU load forecast 2008-2020**

	Summer peak demand	Annual minimum demand	Annual average demand	Annual energy
	(MW sent-out)	(MW sent-out)	(MW sent-out)	(GWH sent-out)
2008	3,521	1,157	1,813	15,878
2009	3,791	1,244	1,949	17,072
2010	3,924	1,299	2,034	17,822
2011	4,037	1,324	2,075	18,173
2012	4,166	1,366	2,139	18,741
2013	4,281	1,395	2,186	19,145
2014	4,380	1,415	2,217	19,417
2015	4,501	1,444	2,262	19,819
2016	4,593	1,463	2,292	20,075
2017	4,691	1,490	2,333	20,437

[7] The demand response begins with a small reduction in 2011, and gradually increases to 12% and 14% demand reductions in 2020.

	Summer peak demand	Annual minimum demand	Annual average demand	Annual energy
	(MW sent-out)	(MW sent-out)	(MW sent-out)	(GWH sent-out)
2018	4,787	1,516	2,374	20,794
2019	4,882	1,542	2,415	21,158
2020	4,975	1,569	2,458	21,528

Data source: IMO

A.3.3 New plant

Table A14 shows new entrant plant from 2011 for 10%, 20% and BAU cases. New entrant wind, biomass and solar PV capacity has been introduced from 2011 based on GWh needed to reach the 20% renewables target by 2020.

Table A14 **New entry plant (MW) - 10%, 20% and BAU**

New Entrant (MW)	10%	20%	BAU
Coal	0	0	600
Natural gas - CCGT	0	0	0
Natural gas - peaker	400	300	1,050
Wind *a*	600	600	0
Biomass	100	100	0
Solar PV	160	160	0
Total	**1,260**	**1,160**	**1,650**

Data source: ACIL Tasman modelling

A.3.4 Capital costs

Black coal fired plant

ACIL Tasman estimates that the project capital cost of a coal-fired plant in the SWIS to be $2,000/kW for 2008.

Our 10-year projection of project capital costs for a new build super-critical coal-fired are presented in Table A15.

Table A15 **Capital costs ($/kW) black coal**

Calendar year	Nominal $/kW	Real (2008) $/kW
2008	$2,000	$2,000
2009	$2,040	$1,990
2010	$2,081	$1,981
2011	$2,122	$1,971
2012	$2,165	$1,961
2013	$2,208	$1,952
2014	$2,252	$1,942
2015	$2,297	$1,933
2016	$2,343	$1,923
2017	$2,390	$1,914

Data source: ACIL Tasman analysis

CCGT

ACIL Tasman estimates that the project capital cost of a CCGT in the SWIS to be $1,400/kW for 2008.

Our 10-year projection of project capital costs for a new build CCGT is presented in Table A16.

Table A16 **Capital costs ($/kW) CCGT**

Calendar year	Nominal $/kW	Real (2008) $/kW
2008	$1,400	$1,400
2009	$1,428	$1,393
2010	$1,457	$1,386
2011	$1,486	$1,380
2012	$1,515	$1,373
2013	$1,546	$1,366
2014	$1,577	$1,360
2015	$1,608	$1,353
2016	$1,640	$1,346
2017	$1,673	$1,340

Data source*: ACIL Tasman analysis*

OCGT

ACIL Tasman estimates that the project capital cost of an OCGT in the SWIS to be $1,000/kW for 2008.

Our 10-year projection of project capital costs for a new build OCGT is presented in Table A17.

Table A17 **Capital costs ($/kW) OCGT**

Calendar year	Nominal $/kW	Real (2008) $/kW
2008	$1,000	$1,000
2009	$1,020	$995
2010	$1,040	$990
2011	$1,061	$985
2012	$1,082	$981
2013	$1,104	$976
2014	$1,126	$971
2015	$1,149	$966
2016	$1,172	$962
2017	$1,195	$957

Data source: ACIL Tasman analysis

A.3.5 Thermal efficiency

ACIL Tasman's estimates of thermal efficiency are provided in Table A18. Our view on the thermal efficiency for the existing technologies has evolved over time and includes analysis of offer curves of existing plant to deconstruct the SRMC cost components. The estimates have been subjected to review from a large number of clients.

Table A18 **Thermal efficiency (HHV, as sent out)**

Technology	Efficiency
CCGT	52%
Supercritical – black coal	40%
OCGT	31%

Data source: ACIL Tasman analysis

A.3.6 Summary of new entrant costs

Table A19 provides estimates of the annualised fixed costs (capital and fixed O&M) of greenfield generation projects in the SWIS. The numbers are based on a discounted cash flow (DCF) model using the long run marginal cost input assumptions presented in this above (input assumptions not mentioned in this section, that is, fixed O&M, auxiliaries, variable O&M and WACC, are the same as in the NEM). The values presented are the fixed costs/kW of installed capacity per year.

Table A19 **Annualised capital plus fixed O&M costs (nominal $/kW/yr)**

Year ending June that plant is installed	CCGT	Black coal	OCGT
2008	$144	$236	$99
2009	$147	$241	$101
2010	$150	$246	$103
2011	$153	$251	$105
2012	$157	$257	$107
2013	$160	$262	$110
2014	$163	$267	$112
2015	$166	$273	$114
2016	$170	$279	$116
2017	$173	$284	$119

Note: These values represent the annualised project capital plus fixed O&M costs required to be recovered each year.
Data source: ACIL Tasman analysis

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STATE OF THE ENERGY MARKET 2009

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CONTENTS

PREFACE

The Australian Energy Regulator (AER) aims to keep stakeholders informed of policy, regulation and market developments in the energy sector. This is the AER's third *State of the energy market* report, which provides a high level overview of energy market activity in Australia. The report is intended to meet the needs of a wide audience, including government, industry and the broader community. The report supplements the AER's extensive technical reporting on the energy sector.

The *State of the energy market* report consolidates information from various sources into one user friendly publication. The aim is to better inform market participants and assist policy debate on energy market issues. The AER is not a policy body, however. In that context, the report focuses on presenting facts, rather than advocating policy agendas.

This 2009 edition consists of a market overview, supported by 11 chapters on the electricity and natural gas sectors. The essay this year is an assessment by EnergyQuest of the state of the natural gas industry, focusing on the growing integration of Australian and global energy markets. There is also an appendix providing background on energy market reform in Australia, including the roles of key policy and regulatory bodies.

The 11 chapters of the report provide more detail on market activity and performance in the electricity and natural gas sectors. The chapters follow the supply chain in each industry—from electricity generation and gas production, through to energy retailing. There is also a survey of contract market activity in electricity derivatives. While the report focuses on activity in the southern and eastern jurisdictions, in which the AER has regulatory and compliance roles, it also contains some coverage of Western Australia and the Northern Territory.

The *State of the energy market* is an evolving project. This year's edition provides increased coverage of energy policy and regulatory developments, including the AER's recent activity. The chapters also provide a stronger focus on key market developments in each sector over the past 12–18 months. The market overview includes some discussion of the implications of climate change policies and the global financial crisis for the energy industry, with the chapters containing more detailed coverage.

Looking forward, the AER will review its approach to *State of the energy market* reporting and consider ways to better inform our audience. As always, we hope to hear the views of readers in this regard. In the meantime, I hope this 2009 edition will provide a valuable resource for market participants, policymakers and the wider community.

Steve Edwell
Chairman

MARKET OVERVIEW


Mark Wilson

MARKET OVERVIEW

Despite difficult economic conditions, there has been considerable momentum in the energy sector over the past 12–18 months. We have seen renewed growth in generation investment, especially in Queensland, New South Wales and South Australia. Network investment is also increasing to meet the challenges of rising peak demand, ageing assets and more rigorous licensing requirements to improve network security.

There has been continued growth and diversification in the natural gas industry, with major projects underway in Western Australia, the continued expansion of Queensland's coal seam gas (CSG) industry and the likelihood of east coast liquefied natural gas (LNG) exports in the next few years. Australia's gas pipeline network continues to expand, with Queensland now interconnected with the south east gas markets, and Bonaparte Basin gas coming onstream in Darwin.

A number of recent policy initiatives will enhance transparency and efficiency in upstream gas markets. The National Gas Market Bulletin Board, which began in July 2008, provides real-time and independent information on the state of the gas market, system constraints and market opportunities. To complement this reform, new spot markets for short term gas trading will begin in the winter of 2010.

On the regulatory front, the transition to national energy regulation has continued. The Australian Energy Regulator (AER) is now the economic regulator of all electricity networks and covered gas pipelines in southern and eastern Australia. It has completed its first determinations for the electricity distribution sector, and is undertaking its first access arrangement reviews in gas distribution.

A new body—the Australian Energy Market Operator (AEMO)—began operation on 1 July 2009 as the single electricity and gas market operator in southern and eastern Australia. It is also coordinating high level national transmission planning and will report on investment opportunities in electricity and natural gas.

Alongside these developments are challenges and concerns. Rising investment and operating costs are significantly increasing network charges and placing upward pressure on retail energy prices. There are also concerns that market power is affecting wholesale electricity prices in some regions.

While generation investment has picked up, there is continued uncertainty over climate change policies. The Australian Energy Market Commission (AEMC) cited concerns that this uncertainty may be delaying generation investment needed for reliability purposes.[1] At the same time, climate change policies are providing momentum for network improvements such as the installation of smart meters to help consumers actively manage their energy consumption.

1 National Electricity Market

The AER closely monitors activity in the National Electricity Market (NEM), which is the wholesale spot market covering Queensland, New South Wales, Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT). It publishes reports on market activity and the compliance of participants with the National Electricity Rules (Electricity Rules).

Wetter conditions in parts of eastern Australia and a mild winter in 2009 led to an easing of wholesale price pressure in most regions of the NEM in the past 18 months or so. Tasmania was the only region in which spot electricity prices rose during 2008–09. Queensland's average spot price in that period was its lowest for several years. While prices fell sharply in South Australia, they remained high relative to those in other mainland regions.

Despite generally benign conditions, concerns remain that some generators have been exercising market power in some regions. The NEM was designed to minimise the risk of market power, through an interconnected transmission grid that allows competition between generators. But there are circumstances in which baseload generators can price capacity at around the market cap and be certain of at least partial dispatch. This behaviour is often more evident at times of peak demand, typically on days of extreme temperatures.

The opportunities for market power are enhanced if transmission interconnector limits are reduced. Given the relatively inelastic demand for electricity and the high market price cap, such circumstances can lead to significant opportunities for price manipulation.

The AER referred in previous *State of the energy market* reports to generators exercising market power in New South Wales in 2007 and South Australia in 2008. These occurrences were reflected in significant price spikes (figure 1). While some price events relate to exogenous factors such as extreme weather, bushfires and unplanned infrastructure outages, a number of spikes in the past two years coincided with strategic generator bidding.

There have been continuing concerns in South Australia, where spot prices in the past two years were significantly higher than in other mainland NEM regions. In the early months of 2009 South Australian spot prices exceeded $5000 per megawatt hour (MWh) on 27 occasions. The bidding strategies of AGL Energy for its Torrens Island power station were a key contributing factor on most occasions. The events typically occurred on days of extreme temperatures and demand, which created a tight supply–demand balance. Under these conditions, Torrens Island can bid a significant proportion of its capacity at around the market cap and be guaranteed at least partial dispatch.

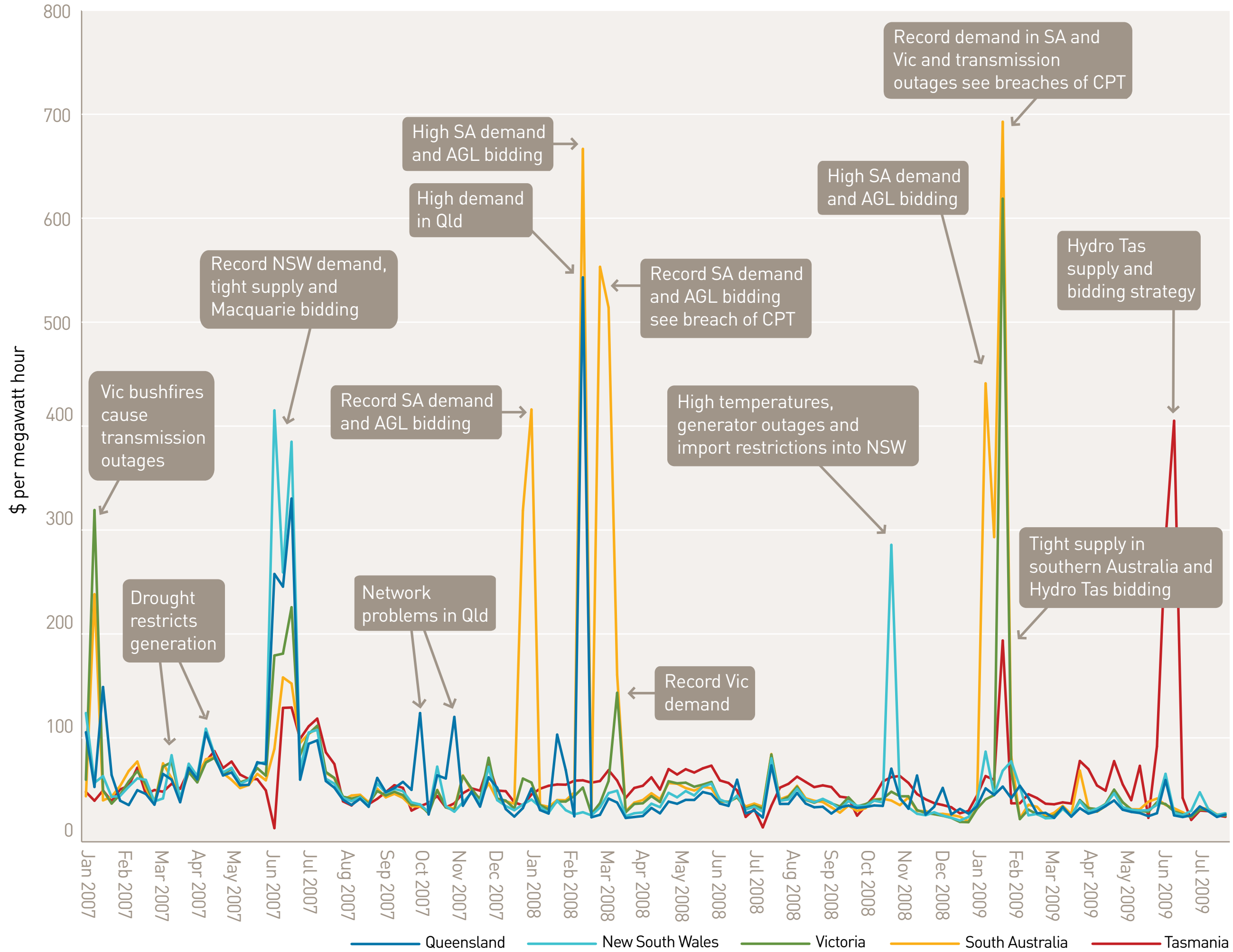
More recently, market bidding strategies emerged as a concern in Tasmania. In June 2009 the spot price in Tasmania exceeded $5000 per MWh on 13 occasions. The spikes were often driven by Hydro Tasmania making sudden and repeated cuts in the output of its non-scheduled (mini hydro) generators, in conjunction with strategic bidding for the rest of its portfolio. The strategy led to administered pricing being applied for four days in June—the first time for Tasmania.

Tasmania also experienced extreme prices for raise contingency frequency control services in early April. The Office of the Tasmanian Economic Regulator has given notice of its intention to declare the supply

1 AEMC, *Review of energy market frameworks in light of climate change policies, final report*, Sydney, October 2009, pp. 81–2.

Figure 1

National Electricity Market—average weekly prices



AGL, AGL Energy; CPT, cumulative price threshold; Macquarie, Macquarie Generation; Hydro Tas, Hydro Tasmania.

Note: Volume weighted prices.

Sources: AEMO; AER.

of these services, which would enable it to regulate prices. While the AER recognises the need for this proposal, such an outcome cannot be seen as a positive development for the market.

The AER monitors activity in the spot market to screen for issues of noncompliance with the Electricity Rules. While bidding capacity at high prices is not a breach of the Rules, it may raise issues under the anti-competitive conduct provisions of the *Trade Practices Act 1974* (Cwth). The AER assists the Australian Competition and Consumer Commission (ACCC) in relation to enforcing these provisions.

The exercise of market power by some generators is a continuing concern. There is evidence that it is leading to increased market volatility and higher spot prices in some regions. The AER will continue to monitor and report on generator bidding behaviour.

The AER reports on all extreme price events in the NEM and conducts more intensive investigations where warranted. It has conducted two recent investigations into the rebidding behaviour of generators. While the Electricity Rules allow generators to amend their original price bids to supply electricity, they require that generators make all bids and rebids in 'good faith.'

The rebidding provisions play an important role in promoting accurate dissemination of information for efficient market dispatch.

In 2008 the AER launched separate investigations into whether Stanwell (a Queensland generator) and AGL Energy (in relation to its South Australian generators) acted 'in good faith' (as contemplated under the Rules) when they rebid capacity during periods of high prices in early 2008. In its investigation findings, published on 12 May 2009, the AER found AGL Energy's bidding was not in breach of the Rules.

The AER investigation into the rebidding behaviour of Stanwell led to it instituting proceedings in the Federal Court, Brisbane. It has alleged that several of Stanwell's rebids of offers to generate electricity on 22 and 23 February 2008 were not in 'good faith'. The AER is seeking orders that include declarations, civil penalties, a compliance program and costs. The matter has been set down for trial in June 2010.

The AER also investigated the operation of the market on 29 and 30 January 2009, when extreme temperatures in Victoria and South Australia led to record electricity demand. There were also significant interruptions to transmission lines and interconnectors on those two days. In combination, these events led to extreme spot prices, administered pricing and supply interruptions. The investigation identified issues relating to the performance of, and reporting on, network capabilities by network businesses, but no breaches of the Rules.

Generation investment and reliability

The *State of the energy market 2008* report referred to concerns that generation investment had been slow to respond to rising electricity demand. There was little generation investment across the NEM in the middle of the current decade, but then tightening supply conditions led to significant new investment in the past few years (figure 2). New investment has occurred in coal and gas fired capacity in Queensland since 2005–06 and in wind capacity in South Australia over the same period. In part, the shift towards investment in gas fired plant and wind generation reflects market expectations that climate change policies will improve the competitiveness of these technologies in the generation mix.

Table 1a sets out major new generation investment that came on line in the NEM in 2008–09, excluding wind. The bulk of new investment—1100 megawatts (MW)—was in privately developed gas fired plant in New South Wales. Origin Energy commissioned the 648 MW Uranquinty plant near Wagga Wagga, and TRUenergy commissioned the 435 MW Tallawarra plant.

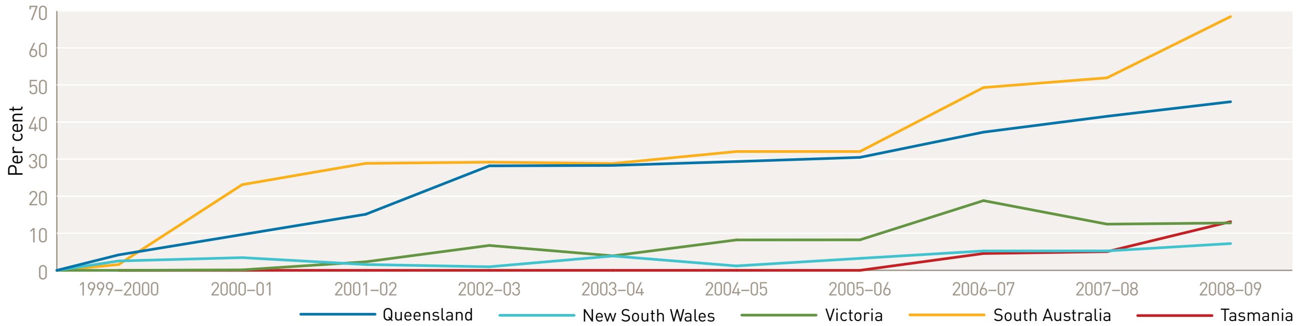
Queensland added around 460 MW of private investment with the commissioning in 2009 of the Braemar 2 plant, developed by ERM Power and Arrow Energy. In South Australia, Origin Energy completed a 128 MW expansion of its Quarantine plant. Government businesses in New South Wales and Tasmania also commissioned new plant in 2009. In addition, Victoria, New South Wales and South Australia recorded around 500 MW of new wind generation capacity.

Table 1b sets out *committed* investment projects in the NEM at June 2009. It includes those under construction and those where developers and financiers have formally committed to construction. There is around 2650 MW of committed capacity in the NEM, of which more than 2000 MW is in gas fired generation. Origin Energy has committed to major developments in Queensland (including a 605 MW plant on the Darling Downs) and Victoria (a 518 MW plant at Mortlake). In addition, government owned generators in New South Wales have committed to significant investment. At June 2009 AEMO reported another 15 490 MW of *proposed* investment, including:

- 8760 MW of non-wind capacity, mostly in gas fired generation for New South Wales, Queensland and Victoria
- 6730 MW of wind capacity, mainly in Victoria, New South Wales and South Australia.

Figure 2

Change in net generation capacity (including wind) since market start



Note: Net change in registered capacity from 1998–99. A decrease may reflect a reduction of capacity due to decommissioning or a change in the ratings of generation units.

Sources: AEMO; AER.

Table 1a Generation investment, 2008–09 (excluding wind)

REGION	POWER STATION	DATE COMMISSIONED	TECHNOLOGY	CAPACITY (MW)	ESTIMATED COST ($ MILLION)	OWNER
Qld	Braemar 2	April–June 2009	OCGT	462	546	ERM Power and Arrow Energy
NSW	Colongra (unit 1)	June 2009	OCGT	157		Delta Electricity
NSW	Tallawarra	February 2009	CCGT	435	350	TRUenergy
NSW	Uranquinty	October 2008 – January 2009	OCGT	648	700	Origin Energy
SA	Quarantine	March 2009	OCGT	128	90	Origin Energy
Tas	Tamar Valley Peaking	April 2009	OCGT	58		Aurora Energy

Table 1b Committed investment in the National Electricity Market, June 2009

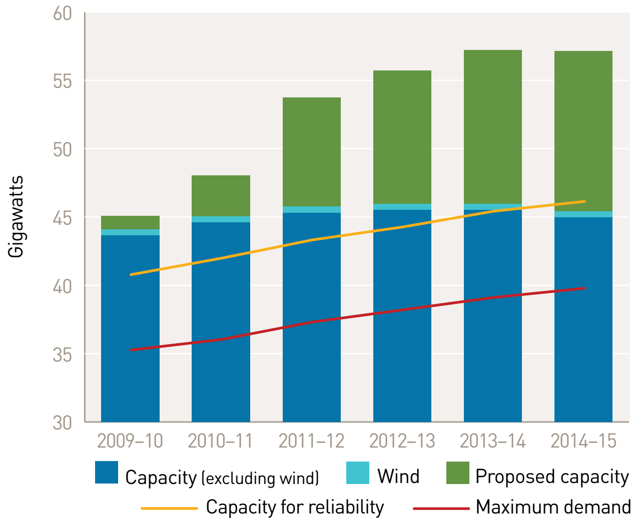
DEVELOPER	POWER STATION	TECHNOLOGY	CAPACITY (MW)	PLANNED COMMISSIONING DATE
QUEENSLAND				
Queensland Gas Company	Condamine	CCGT	135	2009–10
Origin Energy	Darling Downs	CCGT	605	2010
Origin Energy	Mount Stuart (extension)	OCGT	127	2009
Rio Tinto	Yarwun Cogen	Gas cogeneration	152	2010
NEW SOUTH WALES				
Eraring Energy	Eraring (extension)	Coal fired	120	2010–11
Delta Electricity	Colongra (units 2–4)	OCGT	471	
VICTORIA				
AGL Energy	Bogong	Hydro	140	2009–10
Origin Energy	Mortlake	OCGT	518	2010
Pacific Hydro	Portland	Wind	164	2009–10
SOUTH AUSTRALIA				
International Power	Port Lincoln	OCGT	25	2010
TASMANIA				
Aurora Energy	Tamar Valley	CCGT	196	2009

CCGT, combined cycle gas turbine; OCGT, open cycle gas turbine

Note: Capacity is summer capacity for all generators.

Source: AEMO.

Figure 3
Demand and generation capacity outlook to 2014–15



Notes: Capacity (excluding wind) is scheduled capacity and encompasses installed and committed capacity. Wind capacity includes scheduled and semi-scheduled wind generation. Proposed capacity includes wind projects. The maximum demand forecasts for each region in the NEM are aggregated based on a 50 per cent probability of exceedance and a 95 per cent coincidence factor. Unscheduled generation is treated as a reduction in demand. Reserve levels required for reliability are based on an aggregation of minimum reserve levels for each region. Accordingly, the data cannot be taken to indicate the required timing of new generation capacity within individual NEM regions.

Data source: AEMO, *Electricity statement of opportunities for the National Electricity Market*, Melbourne, 2009.

Investment in wind generation continues to rise, especially in South Australia, where it now accounts for around 20 per cent of installed generation capacity. The extent of new and proposed investment in wind generation has raised concerns about system security and reliability. These concerns led to a change of the Electricity Rules, requiring from 31 March 2009 that new wind generators greater than 30 MW must be classified as 'semi-scheduled' and participate in the central dispatch process. This allows AEMO to reduce the output of these generators if necessary. The Australian Government's expanded renewable energy target (RET), passed in August 2009, will likely further stimulate investment in wind generation.

Figure 3 charts forecast peak demand in the NEM against installed, committed and proposed capacity over the next six years. It also shows the amount of capacity that AEMO considers necessary to maintain a reliable power system, given projected demand. It indicates current installed and committed capacity will be sufficient to meet peak demand projections and reliability requirements until at least 2012–13 on a national basis. Individual regions may require generation investment at an earlier date.

While only a small percentage of proposed projects would need to be developed to meet reliability requirements beyond 2012–13, the AEMC has cited uncertainty over the details of climate change policies as one factor that may delay some investment. As the details of climate change policies become more certain, the investment response will likely strengthen.

2 Energy networks

The transition to national regulation of energy networks is continuing. The AER completed its first revenue determinations in electricity distribution in April 2009, for the New South Wales and ACT networks. It also published determinations for the New South Wales and Tasmanian transmission networks at that time.

The AER received its first proposals on access arrangement revisions in gas distribution in June 2009. It is also considering new regulatory proposals for electricity distribution networks in Queensland and South Australia.

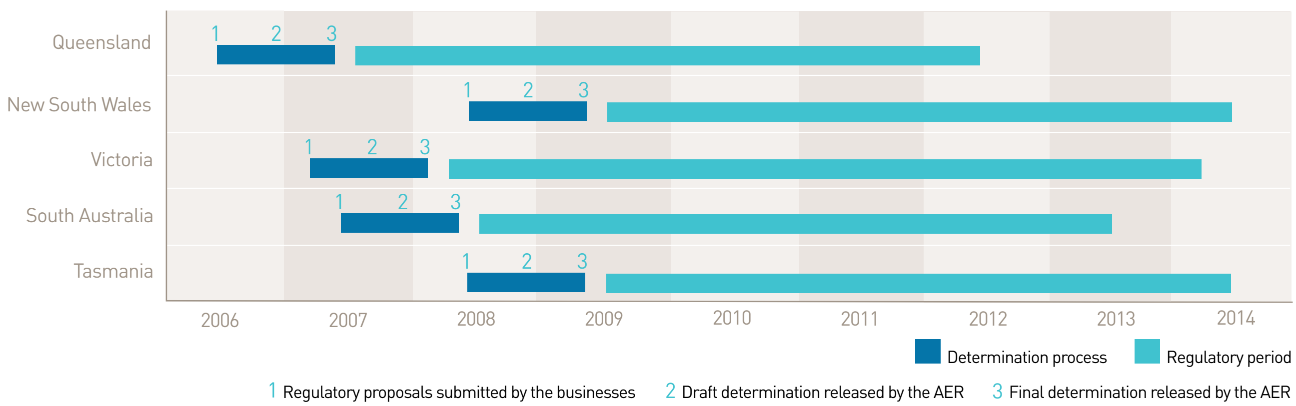
Figure 4 sets out indicative timelines for the AER's consideration of regulatory proposals for energy networks. The AER has published guidelines and frameworks to explain its regulatory approach.

A common feature of recent proposals has been substantial increases in capital and operating expenditure requirements. Figure 5 illustrates new investment under current regulatory proposals and AER determinations compared with investment in previous regulatory periods.

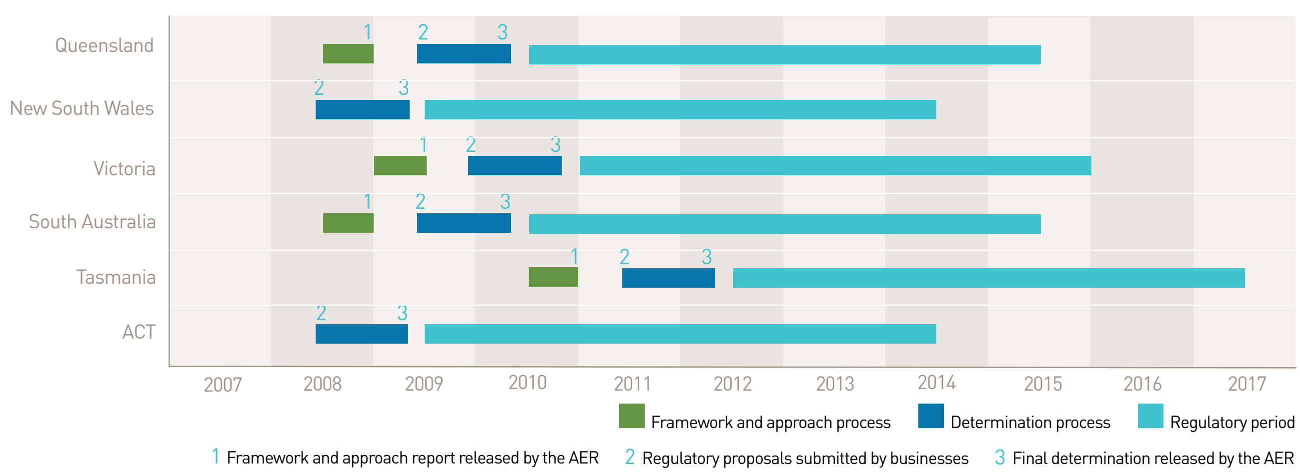
Figure 4

Indicative timelines for AER determinations on energy networks

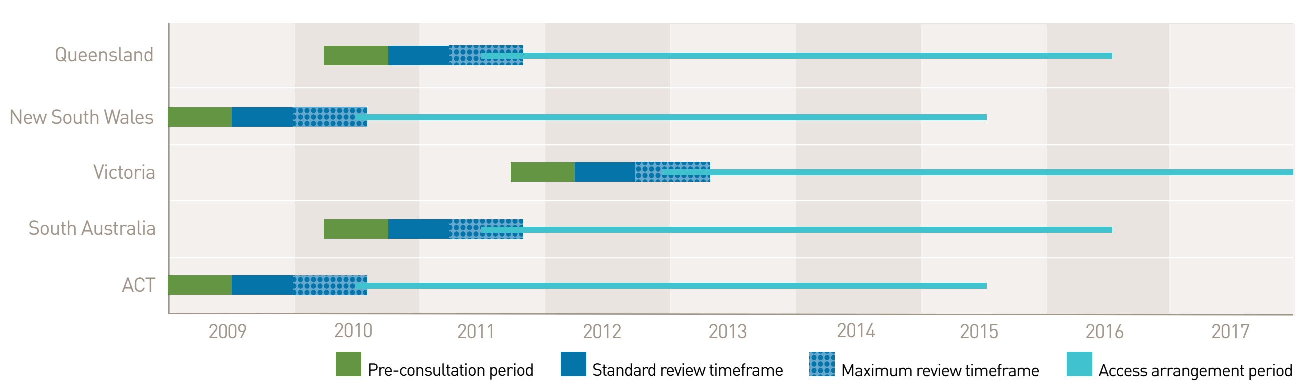
Electricity transmission



Electricity distribution

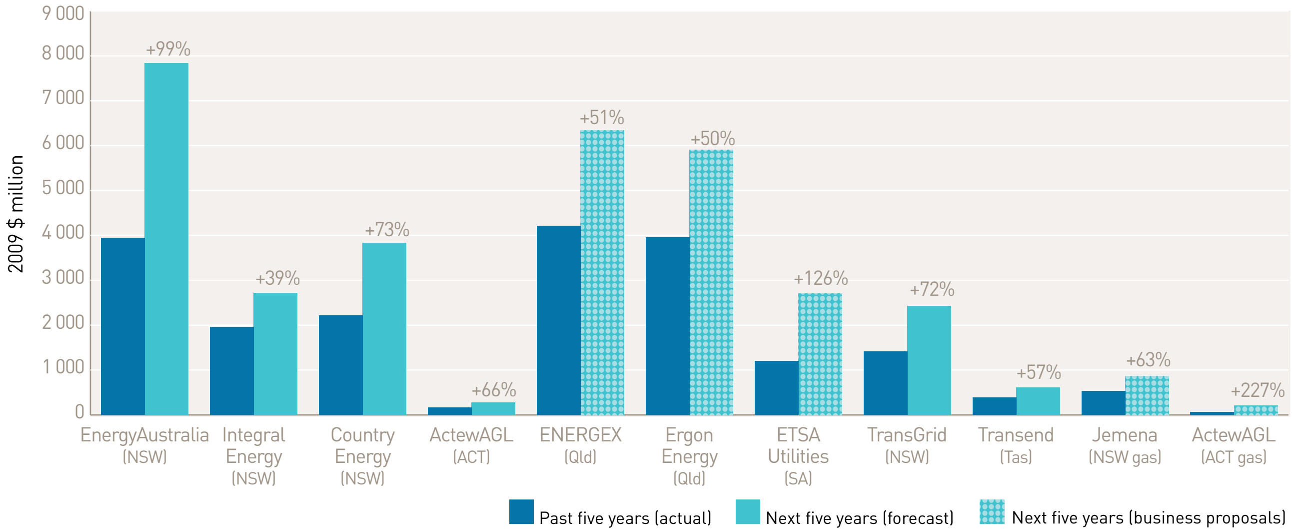


Gas distribution



Note (gas distribution): The timeframes are indicative. The standard review period begins when a gas distributor submits an access arrangement proposal to the AER by a date specified in the previous access arrangement. The timeframes may vary if the AER grants a time extension for the submission of a proposal. An access arrangement period is typically five years, but a provider may apply for a different duration.

Figure 5
Network investment—AER determinations and regulatory proposals, 2009



Note: Proposed investment refers to business proposals not yet assessed by the AER.

Investment in electricity distribution will rise by around 80 per cent in New South Wales and 66 per cent in the ACT in the new five year regulatory cycle. In total, the AER signed off in April 2009 on over $14 billion of distribution investment for New South Wales and the ACT over the next five years. Across the NEM, distribution investment is running at over 40 per cent of the underlying asset base in most networks, over 65 per cent in Queensland and up to 90 per cent in parts of New South Wales.

The story is similar for transmission, for which investment will rise by 72 per cent in New South Wales and 57 per cent in Tasmania over the current regulatory cycle. In total, transmission investment across the NEM was forecast to rise to over $1.6 billion in 2008–09.

A number of factors are driving rising investment requirements. In particular, the networks need to:

> meet load growth and rising peak demand
> replace ageing and obsolete assets
> satisfy more rigorous licensing conditions for network security and reliability.

More generally, all networks face the issue of needing to build capacity to keep air conditioners running on a few very hot days each year.

Several businesses challenged aspects of the recent AER revenue determinations in the Australian Competition Tribunal. In part, the appeals related to inputs in calculating the weighted average cost of capital. The tribunal was considering the appeals in late 2009.

As in New South Wales, the Queensland and South Australian electricity distributors have proposed substantial increases in investment. In South Australia, ETSA Utilities proposed a 126 per cent increase in capital investment over the next five years. In Queensland, ENERGEX and Ergon Energy proposed increases of around 50 per cent. In total, the Queensland and South Australian proposals would involve around $15 billion of investment in the next regulatory cycle.

There are similar trends in gas. Access arrangement revisions for gas distribution networks in New South Wales and the ACT encompass significant increases in investment. Jemena has proposed a 63 per cent increase in investment for its New South Wales gas networks and ActewAGL proposed a 227 per cent increase for the ACT network.

In addition to step-increases in capital spending, operating and maintenance costs are also rising across the networks (figure 6). While these costs are rising less sharply than capital spending, the increases are nonetheless substantial. The Electricity Rules allow network businesses discretion in how they use their capital and operating expenditure allowances. There are also mechanisms to reward businesses for efficient investment and operating programs, balanced with incentives for reliable service delivery.

With network costs accounting for around 50 per cent of a typical electricity bill, rising capital and operating expenditure are flowing through to energy customers. In May 2009 the New South Wales regulator (the Independent Pricing and Regulatory Tribunal) announced that higher distribution charges will increase the average residential electricity bill in the state by around 10 per cent. The impact on large energy users is even greater. The Energy Users Association of Australia has referred to network tariff increases of up to 55 per cent for some large customers.

ETSA Utilities' regulatory proposal would increase distribution charges in South Australia by around 6–7 per cent per year for a small residential customer and 10 per cent for a small business customer. The Queensland proposals would increase distribution charges by around 10 per cent in the first year, followed by annual increases of around 4 per cent.

Energy customers will expect a return for these price increases. In particular, they will look to reliability outcomes and the types of services offered, and in the longer term, to more efficient networks with more competitive pricing structures.

Rising capital and operating expenditure over the past few years has enabled the networks to deliver reasonably stable reliability. The average duration of outages per customer in the NEM has generally been 200–250 minutes per year, allowing for regional variations (figure 7). Electricity customers will look to network businesses to continue to translate rising investment and operating costs into stable or improving reliability outcomes.

While reliability is one aspect of service delivery, network businesses should also look to improve the range of services offered—for example, demand management has many benefits for consumers, from deferring capital expenditure to offsetting the needle peaks in energy demand. The AER has introduced a demand management innovation allowance to encourage network businesses to consider non-network augmentations. The scheme allows businesses to recover implementation costs and forgone revenues from introducing demand management measures. While the scheme is in its early stages, it will mature and likely become more important over time.

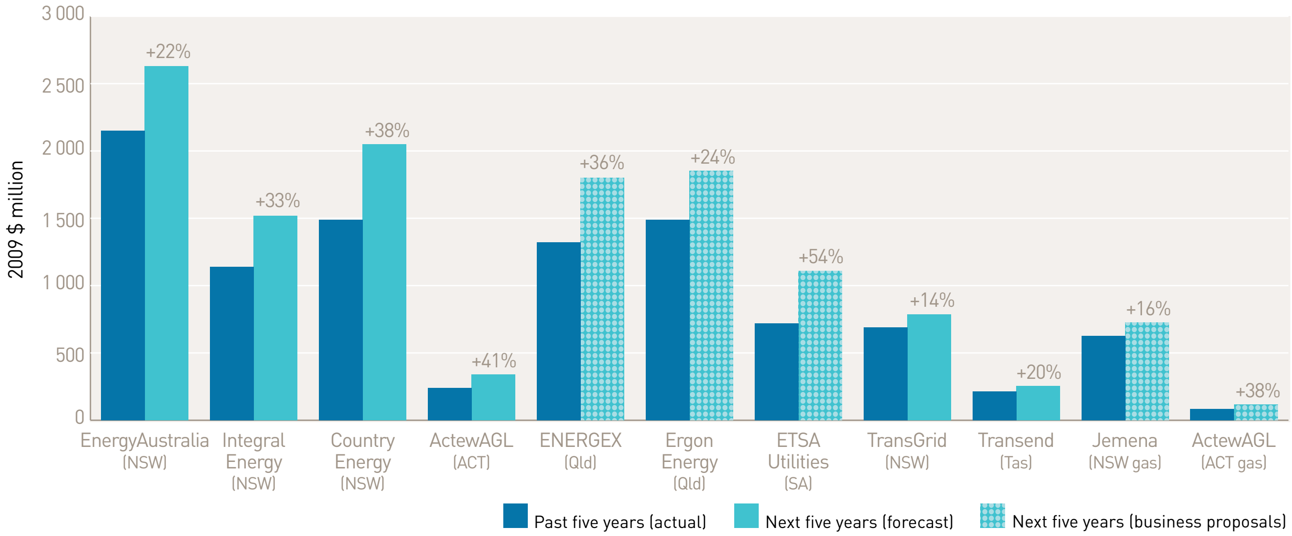
Policy and regulatory responses are underway to enhance network performance. One response is the rollout of smart meters and, potentially, smart grids. Smart meters allow customers to track their energy consumption. When combined with appropriate tariff structures, they can reduce peak and overall demand and delay network augmentations. The Council of Australian Governments has committed to a national rollout of smart meters where the benefits outweigh the costs, with initial deployment in Victoria and New South Wales. The rollout in Victoria began in 2009.

Smart grids take the concept of smart meters further towards direct control of load, the use of communications technology to rapidly detect and switch around faults to minimise supply disruptions, and the integration of embedded generation that can be switched on and off to support the network. The Australian Government recently committed $100 million for a trial of smart grid technologies.

While innovations such as smart meters and smart grids will pose operational challenges for the distribution sector, their introduction can be accommodated within the regulatory framework. The Electricity Rules allow for stable returns on efficient investment in network innovations to improve grid operation and control. If these innovations are accepted into the regulated asset base, the costs will be ultimately borne by consumers, who will expect to benefit through enhanced network performance. In particular, consumers would expect better information on their energy use, which would enable (in the longer term) wider product choice and greater control over their energy consumption and costs.

Figure 6

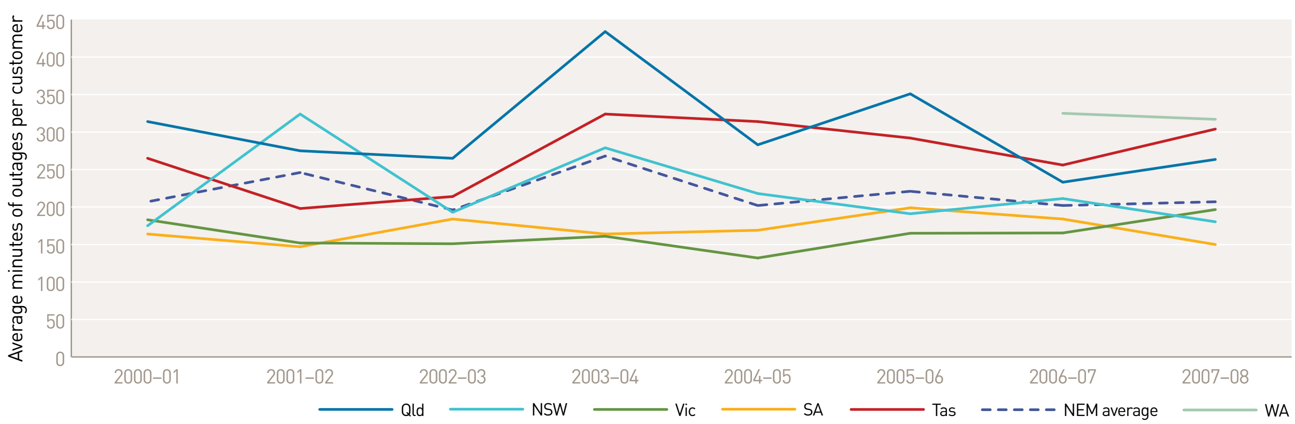
Operating and maintenance expenditure—AER determinations and regulatory proposals, 2009



Note: Proposed investment refers to business proposals not yet assessed by the AER.

Figure 7

Electricity distribution—reliability of supply



Notes:

The data reflect total outages experienced by distribution customers. In some instances, the data may include outages resulting from issues in the generation and transmission sectors. In general, the data have not been normalised to exclude distribution network issues beyond the reasonable control of the network operator. The data for Queensland in 2005–06 and New South Wales in 2006–07 have been adjusted to remove the impact of natural disasters (Cyclone Larry in Queensland and extreme storm activity in New South Wales), which would otherwise have severely distorted the data.

The NEM averages are weighted by customer numbers.

Victorian data are for the calendar year ending in that period.

Sources: Performance reports published by the ESC (Victoria), IPART (New South Wales), the QCA (Queensland), ESCOSA (South Australia), the ERA (Western Australia), OTTER (Tasmania), the ICRC (ACT), EnergyAustralia, Integral Energy and Country Energy. Some data are AER estimates derived from official jurisdictional sources. The AER consulted with PB Associates in developing historical data.

An overarching reform towards more efficient network investment is the establishment of a national transmission planning function within AEMO. The goal is to overlay the traditional jurisdiction based approach to network planning with a more strategic, long term focus on the efficient development of the transmission grid from a national perspective. To this end, AEMO will publish an annual network development plan to complement shorter term regional planning. The first plan is scheduled for release by the end of 2010.

In addition, a new regulatory investment test will help transmission businesses identify effective ways of responding to rising demand for electricity services—for example, in assessing whether the most efficient response is a network augmentation or an alternative such as generation investment. The new test, which takes effect in August 2010, will account for the effects of planned investment on reliability and a range of market impacts. The AER will publish the test and associated guidelines by July 2010.

Similar reforms are underway—but at an earlier stage of development—in distribution. In September 2009 the AEMC recommended a new regulatory test similar to that for transmission.[2] It also recommended more transparent planning requirements, including annual reports that detail projections of load and network capacity and potential projects for the next five years; and arrangements to jointly plan investment affecting both transmission and distribution networks.

Recent reviews have identified impediments to efficient network investment—for example, the AEMC recently recommended changes in interregional transmission charging mechanisms to enhance network planning across regions. The new charging regime is expected to commence on 1 July 2011. The AEMC also recommended reforms in response to climate change policies (see below).

Review of capital costs

A key element of the energy regulatory framework is the return on capital to network owners, which may account for up to 60 per cent of allowed revenues. In May 2009 the AER released a decision on the parameters of the weighted average cost of capital model, which determines the return on capital for regulated electricity networks.[3] The weighted average cost of capital represents the cost of debt and equity required by an efficient benchmark electricity network business to supply regulated electricity services.

The review covered the rate of return values and methods to be adopted in electricity network pricing determinations over the next five years. It was the first review of its type under the Electricity Rules, and its release coincided with the onset of the global financial crisis. Based on the parameters established through the review, the weighted average cost of capital in October 2009 was around 10 per cent—reflecting a cost of debt of 9.7 per cent and an equity return of 10.6 per cent.

The decision accounted for the global financial crisis and recognised the potential for a shift in the market's assessment of risk. More generally, however, the AER takes a long term perspective on the cost of capital. In particular, the regulatory regime should allow returns that provide incentives for efficient investment over the long term—in what are long term assets—rather than reacting to shorter term influences. More recent events in financial markets tend to reinforce this view, with equity yields and credit spreads moving back towards levels more in keeping with those before the global financial crisis.

Businesses will continue to be compensated for any rises in debt margins at each reset. This compensation, being based on a benchmark corporate bond of BBB+ rating, is well above that which higher rated network businesses incur. More generally, evidence from a number of sources suggests the regulatory regime helps insulate network businesses from market volatility. Significantly,

2 AEMC, *Review of national framework for electricity distribution network planning and expansion, final report*, Sydney, September 2009.

3 AER, *Electricity transmission and distribution network service providers: review of the weighted average cost of capital (WACC) parameters, final decision*, Melbourne, May 2009.

the ability of a regulated network business to align its debt issuance to the time of a regulatory determination mitigates a large proportion of the risks associated with rising debt costs.

3 Climate change policies

Australian governments are implementing measures to encourage the use of low greenhouse gas emission technologies. These policies have significant implications for energy markets. The Australian Government's primary emissions reduction policies are an expanded RET and a proposed emissions trading scheme—the Carbon Pollution Reduction Scheme (CPRS).

On 20 August 2009 the Commonwealth Parliament passed legislation to implement the expanded RET scheme. The scheme requires 20 per cent of Australia's electricity generation to come from renewable energy sources by 2020. It increases the pre-existing national target by more than four times to 45 850 gigawatt hours in 2020, before falling to 45 000 gigawatt hours in the following decade. The scheme is set to expire in 2030, when the proposed CPRS is intended to provide sufficient stimulus for renewable energy projects.

The expanded scheme aims to encourage investment in renewable energy technologies by providing for the creation of renewable energy certificates. One certificate is created for each megawatt hour of eligible renewable electricity generated by an accredited power station, or deemed to have been generated by eligible solar hot water or small generation units. Retailers must obtain and surrender certificates to cover a proportion of their wholesale electricity purchases. If a retailer fails to surrender enough certificates to cover its liability, then it must pay a penalty for the shortfall.

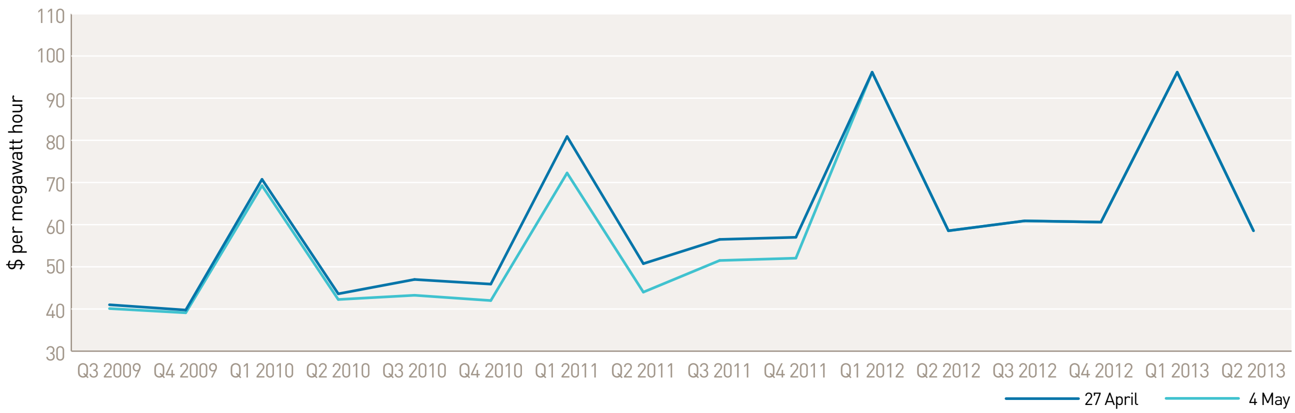
The design of the proposed CPRS was set out on 15 December 2008 in the *Carbon Pollution Reduction Scheme: Australia's low pollution future* (white paper). It aims to create a market for the right to emit carbon by placing a cap on Australia's total emissions. It is designed as a broad based trading scheme, covering sectors responsible for around 75 per cent of Australia's carbon emissions. The target for emissions reduction will depend on international mitigation efforts. The Australian Government has committed to a minimum 5 per cent reduction in emissions (from 2000 levels) by 2020, with the potential for a 25 per cent reduction by 2020 in the event of coordinated international action.

On 4 May 2009 the Australian Government announced a one year delay in the introduction of the CPRS, to 1 July 2011. Figure 8 illustrates how this announcement affected prices for electricity base futures on the Sydney Futures Exchange. Taking Victorian contracts as an example, the chart compares base futures prices on 27 April 2009 (one week before the announcement) with prices on 4 May 2009 (after the announcement). The difference between the lines approximates market expectations of the net impact of the CPRS on future spot electricity prices. The impact is predictably stronger during the summer peak period, but is mostly around $5 per MWh. As expected, the impact was minimal outside the period of the delay.

Climate change policies pose challenges and opportunities for the energy sector. In particular, coal fired electricity generation, which accounts for around 85 per cent of Australia's generation output, is emissions intensive. The introduction of the CPRS may result in some asset write-downs. Mitigating factors such as forward market trading, vertical integration and new investment in gas fired generation are likely to ease the risk of possible supply issues.

There has been debate over the issue of assistance to coal fired generators. The white paper proposed a one-off assistance package for the energy sector, consisting of free carbon permits directed at mainly brown coal generators, valued at around $3.6 billion. The Australian Government has engaged Morgan Stanley to further review the forecast impacts of climate change policies on high emission plant.

Figure 8
Victorian electricity base futures prices



Q, quarter

Source: d-cyphaTrade.

The CPRS is likely to improve the competitiveness of gas fired generation in relation to coal fired technology. This is reflected in the extent of gas fired generation in recent and committed investment decisions, including 2400 MW of new capacity in 2008–09 (tables 1a and 1b). There will be substantial opportunities for the natural gas industry, although rising demand for gas—both for electricity generation and for likely LNG exports from eastern Australia—may increase gas prices in the longer term and partly neutralise its cost advantages (section 6).

As the cheapest and most mature renewable energy technology, wind generation is likely to grow significantly under the expanded RET. But wind generation depends on prevailing weather conditions, and its intermittent nature poses challenges for power system reliability and security. In addition, momentary fluctuations in wind output create issues for maintaining power flows within the capacity limits of transmission infrastructure. To maintain reliability and security, standby capacity—in transmission and generation that can respond quickly to changing market conditions—is required. Peaking plant (such as open cycle gas turbines) typically provides standby generation capacity. This may necessitate refinements in the market's design, in terms of inertia services and the procurement of transmission network control services.

In the longer term, there is potential to develop other renewable energy technologies, such as geothermal, solar, wave and tidal generation. Additionally, carbon capture and storage technologies that extract carbon dioxide from fossil fuel power plants and store it in deep geological formations may become viable. None of these technologies is currently capable of large scale entry into the market, given either technical issues or cost.

Review of energy market frameworks

In October 2009 the AEMC completed a review of Australia's energy market frameworks in light of climate change policies. It found the frameworks are efficient and robust enough to deal with most issues, but need refinements.

In relation to generation, the report considered concerns that the potential early closure of some coal fired plant could lead to short term capacity shortfalls. The current reliability mechanisms to address this risk include:

> AEMO's power to direct generators to provide additional supply
> the reliability and emergency reserve trader mechanism, which allows AEMO to enter reserve contracts with generators to ensure sufficient supply.

The proposals to address potential capacity risks include allowing AEMO more flexibility to procure emergency supplies, such as through short notice contracting.

The AEMC also proposed more accurate reporting of demand-side capability and the removal of regulatory barriers to using embedded generation to meet supply shortfalls. These changes would better place AEMO to minimise intervention in the market and avoid involuntary load shedding.

The increasing use of gas fired and renewable generation will present challenges for the network sector. Electricity networks have developed around the location of coal fired generation plant. New investment in renewable generation, however, is likely to occur in areas not presently serviced by networks. Specifically, the transmission network may need augmentation to deliver electricity from remote generators to load centres.

The AEMC has proposed an approach whereby transmission businesses can size network extensions to remote generators to accommodate anticipated future needs, with customers underwriting the risk of asset stranding. The AER will have a role in ensuring consumers' interests are protected. Additionally, in August 2009 the AEMC amended the confidentiality provisions for network connection applications, to allow for a more coordinated approach under the existing framework.

The sourcing of large volumes of electricity from new locations on the network may also affect flows and create new points of transmission congestion. Congestion can sometimes impede the dispatch of cost-efficient generation and create opportunities for the exercise of market power.

The AEMC has proposed a form of generator transmission use-of-system charge to provide better locational signals for new generation investment (and exit) that would avoid significant increases in network congestion. The new charging system would provide price signals to investors on areas of the network that may require new capacity.[4] Given the proposal represents a significant departure from current arrangements, the AEMC will establish a working group to develop an implementation plan by late 2010.

Climate change policies have implications for the natural gas sector. Greater reliance on gas fired generation would increase both the level and volatility of gas demand. Generators are likely to need access to large quantities of gas at relatively short notice at times of peak demand and to back up intermittent generation. This will likely require substantial new investment in gas pipeline and storage capacity, as well as greater flexibility in gas contracting arrangements. The convergence of the electricity and gas markets also raises issues of security of supply. Any response to emergency shortfall events in one part of the energy market will need to consider consequences across the energy sector as a whole. Section 6 further discusses gas market activity.

4 Global economic and financial conditions

From late 2007 the emergence of the global financial crisis has affected the availability and cost of funding for new investment and refinancing. This impact has been particularly evident in significant increases in risk premiums on all forms of debt.

While Australian financial and economic conditions have remained relatively robust, the crisis has had ramifications for the energy sector. Coal fired generators have raised concerns that tighter liquidity and more risk averse financial markets have made it more difficult to refinance debt. More generally, they argue that financial conditions have aggravated the risks they already face from the introduction of climate change policies. Financial conditions have also raised issues for new entrant generators, and might have delayed some new investment that would have increased competitive pressures on incumbents. Further, less finance has been available to develop renewable technologies such as for solar and geothermal generation.

Tighter credit markets have also posed issues for energy retailers—for example, those seeking access to prudential cover to support wholesale and contract

4 The AEMC is also exploring the need for congestion pricing at points on the network with prolonged and material levels of congestion.

Construction of Origin Energy's Darling Downs gas fired power station (Origin Energy) market exposures—as well as for network businesses and gas industry participants.

As noted, the AER accounted for the impact of the global financial crisis in its 2009 review of capital costs for regulated networks (section 2). It increased the market risk premium to 6.5 per cent (from the previous value of 6 per cent), for example, recognising the uncertainty in financial markets. Similarly, it took a cautious approach to interpreting empirical evidence on the equity beta of a benchmark electricity network business, by adopting a value above the range indicated by empirical estimates.

The AER is also accounting for financial conditions in revenue determinations for regulated networks. The recent New South Wales and ACT electricity distribution determinations, for example, took account of the effects of financial conditions on demand forecasts, the cost of capital, materials and labour input cost escalators, and defined benefit superannuation costs in operating expenditure forecasts.

EnergyQuest's essay in this report discusses the effects of the financial crisis on gas markets. It notes that while the recession has weakened global demand for gas, Australian LNG exports have increased against this trend. Domestically, the downturn does not appear to have significantly affected gas consumption. The essay also notes, while financing has become more difficult and expensive since 2007, that Australian gas development projects have not been seriously affected. Companies have managed to raise finance, rationalise exploration and sell non-core assets to fund key projects.

The relatively high gearing of pipeline companies has created difficulties for them in obtaining finance at an acceptable cost for new projects. A proposed expansion of the South West Queensland Pipeline to provide capacity for Origin Energy, for example, was made subject to obtaining the necessary funding on acceptable commercial terms.

Financial market conditions have contributed to some changes in asset ownership across the energy sector. Babcock & Brown Power, for example, sold a number of generation assets and trading contracts. In December 2008 APA Group spun off some of its network assets into a new unlisted investment vehicle, and applied the proceeds to reduce \$647 million of corporate debt. More generally, EnergyQuest notes in its essay that companies are reviewing their portfolios and disposing of non-core assets to fund core projects. It notes that competition has generally been keen for those assets offered for sale.

5 Retail markets

The first exposure draft of legislation to establish a national energy customer framework was released on 30 April 2009. The legislation will transfer several non-price retail functions from state and territory jurisdictions to the AER. Consultation on a second exposure draft was scheduled for late 2009, and the legislation is scheduled for introduction to the South Australian Parliament in spring 2010.

Under the proposed framework, the AER will be responsible for authorising (licensing) energy retailers, approving authorisation exemptions, monitoring retailers' compliance with the legislation and undertaking any enforcement action, and providing guidance on matters such as hardship issues and how retailers represent their products to customers. The states and territories will retain responsibility for any continuing price regulation, unless they choose to transfer those arrangements.

Market structure

AGL Energy, Origin Energy and TRUenergy collectively account for most retail market share in Victoria, South Australia and Queensland, but Simply Energy (owned by International Power) has acquired a significant customer base in Victoria and South Australia. There has also been ongoing new entry by niche businesses. Retailers with full or part government ownership supply the bulk of customers in other jurisdictions.

The New South Wales Government in September 2009 released the *Energy Reform Transaction Strategy*, outlining the proposed structure for the sale of its three state owned energy retailers: EnergyAustralia, Integral Energy and Country Energy. Bidders for EnergyAustralia will have the flexibility to bid for its gas and electricity customers separately, or for both. The government also proposes to contract out the right to sell electricity produced by state owned generators to the private sector, and to sell seven power station development sites. Subject to market conditions, it expects to complete the sale process in the first half of 2010.

The New South Wales Government will simultaneously prepare for a share market listing of an entity that includes the retail business of Integral Energy, the generation trading contract for Eraring Energy and the Bamarang power station development site. The float will proceed if the initial sales process fails to meet the government's strategic, competition and valuation requirements.

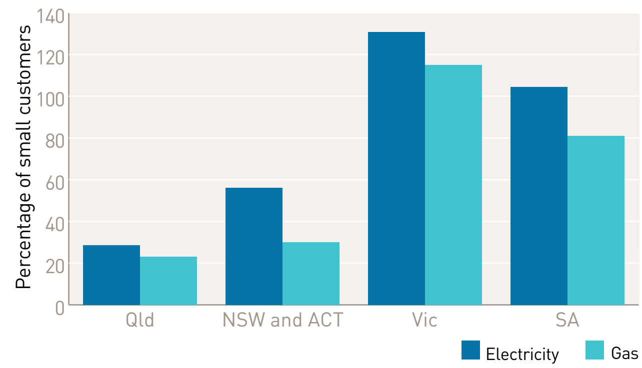
Retail competition

Energy retail competition has continued to develop over the past year. Customer switching continued strongly in Victoria (and, to a lesser extent, in South Australia and Queensland) in 2008–09. Cumulative switching rates for small customers in Victoria and South Australia are about double those for New South Wales (figure 9). The low rates for Queensland partly reflect that small customer switching has been possible only since July 2007. Across all jurisdictions, switching rates are higher in electricity than in gas, although the rates are comparable in Victoria, where gas is used more widely for household purposes than in other states. South Australia and Victoria have also reported high rates of customer movement from standing offer contracts to market contracts with their host retailer.

While most jurisdictions allow customers to choose their energy retailer, jurisdictions other than Victoria apply some form of electricity retail price regulation, and several apply similar arrangements in gas. The AEMC is assessing the effectiveness of energy retail competition in each jurisdiction to advise on the appropriate time to remove retail price caps, with state and territory governments making final decisions.

Figure 9

Cumulative retail switching to 30 June 2009—small customers



Notes:

Cumulative switching as a percentage of the small customer base since the start of full retail contestability: Victoria and New South Wales 2002; South Australia 2003 (electricity) and 2004 (gas); Queensland 2007.

If a customer switches to a number of retailers in succession, each move counts as a separate switch. Cumulative switching rates may, therefore, exceed 100 per cent.

Sources: Electricity customer switches: AEMO. Gas customer switches: AEMO (Queensland, New South Wales, the ACT, Victoria), REMCo (South Australia). Customer numbers: IPART (New South Wales), ICRC (ACT), ESCOSA (South Australia), ESC (Victoria), QCA (Queensland).

Victoria responded to an AEMC review by removing retail price caps on 1 January 2009. To balance this change, the Essential Services Commission of Victoria is monitoring and reporting on retail prices. In addition, retailers must publish a range of offers, to help consumers compare energy prices. Other obligations on retailers, including the obligation to supply and the consumer protection framework, remain in place. The Victorian Government retains a reserve power to reinstate price regulation if competition is found to be no longer effective.

The AEMC review of South Australian retail energy markets, completed in December 2008, found competition was effective for small customers, but more intense in electricity than in gas. It noted, while overall competition was effective, that the state's relatively high wholesale prices, price volatility and increasing vertical integration may limit further new entry. The AEMC proposed that South Australia introduce price monitoring to support the competitive market, and that it retain reserve powers to re-introduce price regulation if competition deteriorates. In April 2009 the South Australia Government stated it did not accept the AEMC's recommendations at that time. It was concerned that more than 30 per cent of small customers remain on standing contracts and that stakeholders have differing views on the effectiveness of competition.

The Ministerial Council on Energy has agreed to proceed with reviews of retail competition for the ACT in 2010, New South Wales in 2011, Queensland in 2012 and Tasmania in 2013 (if it introduces full customer choice by that time). The AEMC recommended in October 2009 that jurisdictions bring forward their consideration of the removal of retail price regulation.[5] For those jurisdictions that retain regulated energy prices beyond the introduction of the proposed CPRS, the AEMC recommended that price setting frameworks allow for regular wholesale energy and carbon cost reviews (as frequently as six monthly). Prices could then be adjusted if costs have changed materially.

The Queensland Competition Authority is reviewing its electricity retail price setting framework. The review aims to ensure the framework captures all relevant costs (including costs from environmental obligations) and provides flexibility to set tariff structures that will encourage customers to use electricity efficiently. Queensland expects to apply the review's recommendations in setting retail prices for 2010–11.

Retail prices

As noted, retail price pressure is an emerging concern in energy markets. In 2009 several jurisdictions announced significant increases in regulated electricity prices, in response to rising network and wholesale energy costs:

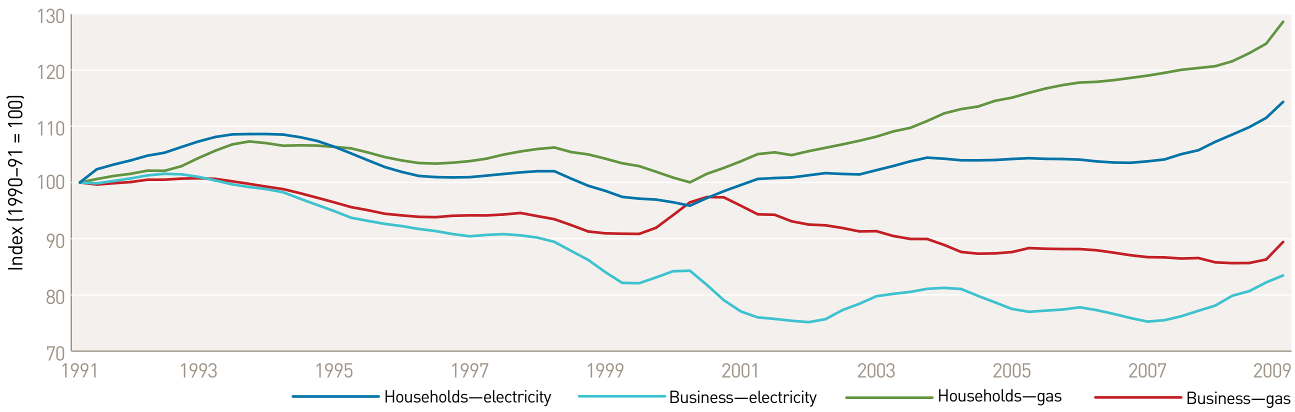
- In New South Wales, a typical retail electricity bill will rise by around 18–22 per cent in 2009–10. About 50 per cent of the increase is due to higher network costs.
- The Queensland Competition Authority announced in June 2009 that regulated electricity retail prices for 2009–10 would rise by 11.82 per cent. Following a successful appeal by Origin Energy and AGL Energy, the authority announced a further increase that would raise prices in total by 15.5 per cent.
- The Independent Competition and Regulatory Commission announced that retail electricity prices in the ACT would increase by up to 6.4 per cent in 2009–10, mainly reflecting higher network costs.
- In Western Australia, the Office of Energy recommended in 2008 that retail electricity prices increase by 52 per cent, following several years of declining real prices. The Western Australian Government rejected this recommendation and announced that residential prices would increase by 10 per cent on 1 April 2009, and by a further 15 per cent on 1 July 2009.
- In the Northern Territory, electricity tariffs for non-contestable customers rose by 18 per cent from 1 July 2009.

Figure 10 estimates movements in real energy retail prices (under regulated and market arrangements) in major capital cities over time. It illustrates the recent upswing in electricity and gas retail prices, especially for households. The tendency for household customers to experience larger price rises than business customers partly reflects the continued unwinding of historical cross-subsidies in some jurisdictions. More generally, it illustrates that household customers are increasingly exposed to prices in wholesale energy markets.

Climate change policies will likely add further upward pressure on retail prices. McLennan Magasanik Associates' modelling for the Australian Treasury estimated that a carbon emissions price of $35 per tonne (A$2005 prices) in 2020 could result in household electricity prices rising by up to 23 per cent.[6] Retail gas prices are also likely to rise as demand for gas fired generation increases.

5 AEMC, *Review of energy market frameworks in light of climate change policies, final report*, Sydney, October 2009, p. v.
6 MMA, *Impacts of the Carbon Pollution Reduction Scheme on Australia's electricity markets*, Report to Federal Treasury, Melbourne, December 2008, p. 7.

Figure 10
Electricity and gas retail price index (real)—Australian capital cities



Sources: ABS, *Consumer Price Index* and *Producer Price Index*, cat. no. 6401.0 and 6427.0, Canberra, various years.

6 Upstream gas

In a commissioned essay for this report, EnergyQuest examines the strengthening links between Australia's natural gas industry and global energy markets. The industry continues to expand rapidly, driven by buoyant interest in Australian LNG exports, investment in gas fired electricity generation, and a rapidly expanding resource base of CSG in Queensland and New South Wales.

Australia is now the world's sixth largest LNG exporter. Notwithstanding a recent easing in LNG demand, oil and gas companies are committing to spend billions of dollars on new Australian projects. The $50 billion Gorgon project in Western Australia is scheduled to begin operation in 2014 and produce around 15 million tonnes of LNG per year—equal to Australia's current total LNG production.

Also on the west coast, the 4.3 million tonne per year Pluto project is under construction and set to become Australia's third operational LNG project. Pluto is due for completion in 2010 and will supply major Japanese buyers.

Long term projections of rising international energy prices, together with rapidly expanding reserves of CSG in Queensland, have improved the economics of developing LNG export facilities in eastern Australia. Four export projects that rely on CSG are at an advanced stage of planning. Most are at the front end engineering and design stage, aiming for final investment decisions by the end of 2010. The proposals range in size from 1.5 to 14 million tonnes of LNG per year. Over 20 million tonnes per year from these projects is already committed to buyers.

On the domestic front, weaker economic growth in 2009 led to a softening in gas demand on both sides of the country. In Western Australia, weaker global energy prices also took some pressure off domestic gas prices. On the east coast, Victoria's spot market provides the most transparent price signals. Spot prices averaged $2.68 per gigajoule for June quarter 2009, down 19 per cent on June quarter 2008.

Activity is strong in the increasingly deregulated gas transmission sector, which is taking a longer term view. Climate change policies, new investment in gas fired peaking generators and Queensland's burgeoning CSG industry are driving significant investment in gas transmission infrastructure.

The commissioning of the QSN Link and expansion of the South West Queensland Pipeline in 2009 brought Queensland into an interconnected pipeline network spanning Queensland, New South Wales, Victoria, South Australia, Tasmania and the ACT. This is moving us closer to a national gas market.

For the first time, CSG from Queensland can compete in southern markets with gas produced in the Cooper and Victorian gas basins.

Further dynamic change is likely in the east coast gas markets with the development of CSG–LNG projects around Gladstone in the next few years. While this development may increase wholesale gas prices in the longer term, EnergyQuest predicts domestic prices may ease during the lengthy ramp-up of LNG export capacity.

While upstream gas is a lightly regulated sector, there have been significant developments to enhance transparency. The National Gas Market Bulletin Board, which began in July 2008, provides real-time and independent information on the state of the gas market, system constraints and market opportunities. And with plans to launch a new annual statement of opportunities for gas (similar to that published for electricity), AEMO aims to improve information for planning and commercial decisions on investment in gas infrastructure. The first gas statement is scheduled for publication in December 2009.

To complement these reforms, new spot markets (in addition to that operating in Victoria) for short term gas trading will begin next winter. The first markets will be based around the Sydney and Adelaide hubs. While the markets relate to gas for balancing purposes, they will provide transparent price guidance for the market as a whole. Any move to greater depth in short term gas markets will better enable Australian energy markets to maximise the benefits of any 'surplus' gas associated with gas export projects.

7 The Australian Energy Regulator's role

As the transition to national energy regulation continues, the AER is mindful of its responsibilities as the regulator of energy infrastructure in eastern and southern Australia. In addition to regulating network assets, it monitors the wholesale energy markets for compliance with the underpinning legislation, and reports on market activity.

The AER will continue to work closely with industry and energy customers in undertaking these roles. It will look to apply consistent and transparent approaches to encourage efficient investment and reliable service delivery. Across its work program, the AER will continue to work towards best practice regulatory and enforcement outcomes, including the provision of independent and comprehensive information on market developments.

PART ONE
ESSAY

AUSTRALIA'S NATURAL GAS MARKETS: CONNECTING WITH THE WORLD

A report by EnergyQuest

ESSAY

AUSTRALIA'S NATURAL GAS MARKETS: CONNECTING WITH THE WORLD

A report by EnergyQuest

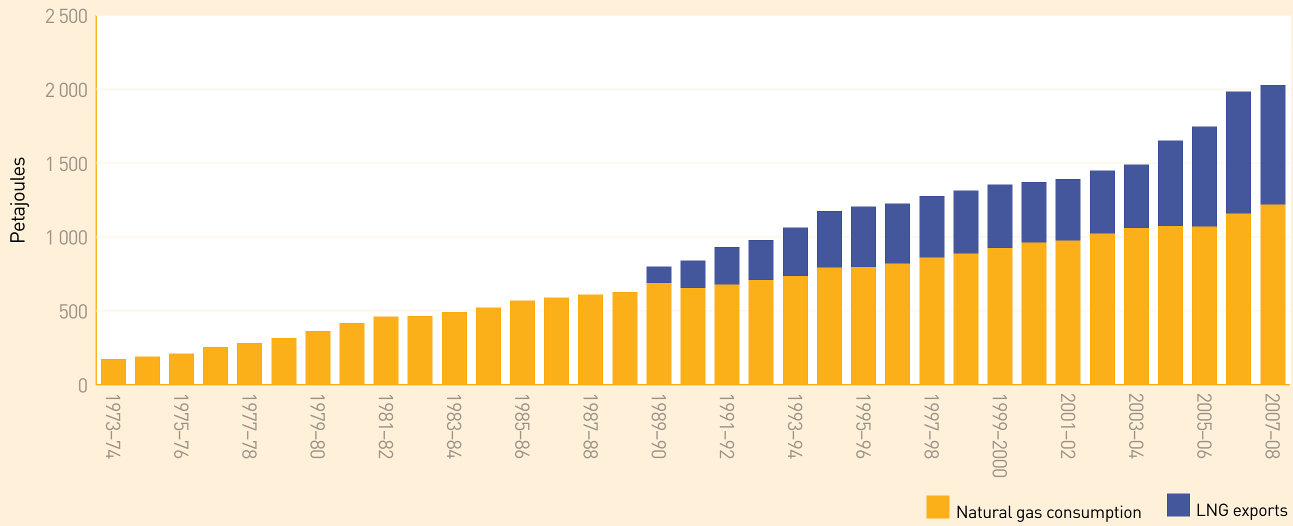
EnergyQuest is an advisory firm focused on energy analysis and strategy.

Historically, natural gas markets in eastern Australia were isolated from the rest of the world. While Western Australia's gas market was linked to global markets through liquefied natural gas (LNG) exports, the impact on the domestic market was limited. A number of developments are now leading to closer integration of gas markets in Australia and the rest of the world. This essay explores some of these developments.

Australia's LNG is a pivotal link between domestic and international markets. In the early 1970s Woodside discovered immense gas resources off the Western Australian coast, which could not only meet the state's domestic needs but also supply Asian markets. Export production began in the late 1980s. The North West Shelf now has five trains (processing plants) with a total annual capacity of 16.3 million tonnes. In 2006 Australia's second LNG plant commenced exporting from Darwin. With these developments, Australia's annual LNG capacity has risen to 19.5 million tonnes (nearly 1100 petajoules (PJ) a year—close to Australia's total domestic demand for natural gas). Figure E.1 illustrates Australian LNG export growth relative to domestic demand. As will be discussed, Western Australia's domestic gas market is increasingly integrated with the global market by way of LNG, and similar events look set to occur on the east coast.

Figure E.1

Australian natural gas production



Source: ABARE.

A second link between Australian gas markets and the rest of the world is the exponential rise of coal seam gas (CSG) on the east coast. This has become closely linked with major LNG developments and is attracting significant foreign investment.

Interest in CSG began in the United States and has contributed to a reversal in the historic decline in US gas production. With its world class coal resources, Australia has been recognised as having immense CSG potential since the 1980s. A number of major international oil and gas companies tried to commercialise CSG in Queensland and New South Wales but with mixed results. Texan father and son Dr James Butler and James Butler Jr, founders of Tri-Star Petroleum, are credited with Australia's first commercially viable CSG, produced from the Fairview field in 1998. They also discovered the Durham Ranch field, later developed by Origin Energy as the Spring Gully project. Ultimately, after years of trial and error, the industry began to develop early this decade.

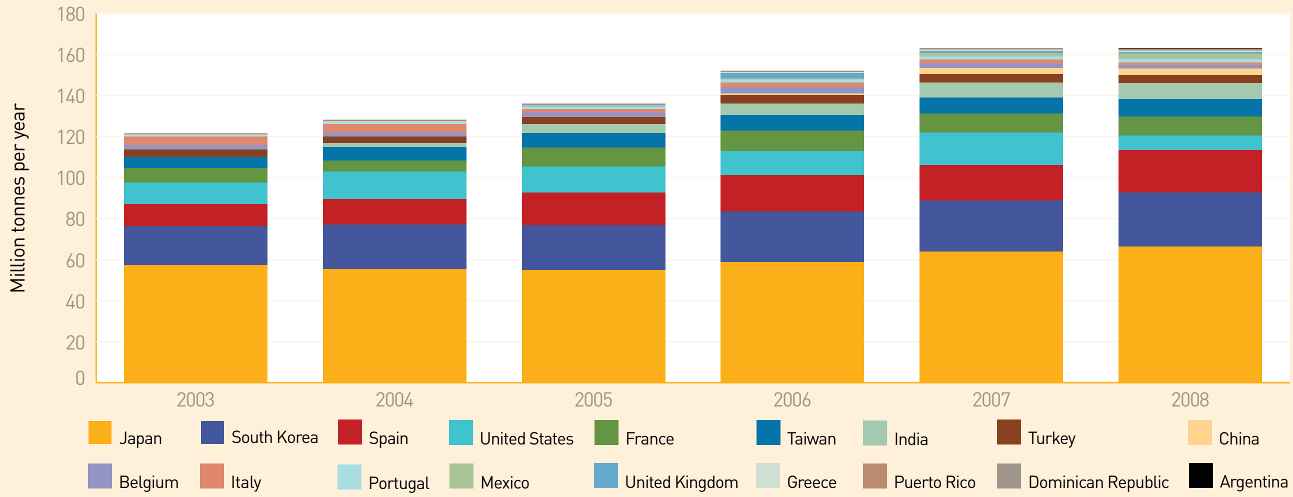
The early focus of CSG production was as a supplement to conventional gas for domestic use in Queensland. In particular, the Queensland Government promoted the use of CSG for electricity generation through the Queensland Gas Scheme. The state previously planned to import gas from Papua New Guinea to address supply issues, but the growth of CSG ultimately eroded the commercial viability of that option.

It soon became apparent that while Queensland had more CSG than could be absorbed by the east coast domestic gas market—or commercialised at low Australian gas prices—the burgeoning global LNG market had potential, as with the North West Shelf discoveries three decades earlier.

This created interest among international LNG companies who wanted gas reserves in the Asia Pacific region and were familiar with the growth of unconventional gas in the United States. As a result, several international companies have taken a stake in Queensland CSG for LNG projects. The east coast gas market now appears set to follow Western Australia in becoming more closely integrated with the rest of the world through LNG.

Climate change is a third global influence on Australian gas markets. For many years natural gas played a lead role in power generation in only South Australia and Western Australia, which lacked large supplies of commercial coal. Along the east coast, coal has been king in power generation. But global concerns about climate change, as reflected in Australia's proposed Carbon Pollution Reduction Scheme, now look set

Figure E.2
World imports of liquefied natural gas



Source: BP, *Statistical review of world energy 2009*, London, 2009.

to change the technology mix in power generation. A range of fuels and technologies will increasingly compete to provide cleaner electricity. Natural gas produces around half the greenhouse emissions of coal when used in combined cycle gas turbines for electricity generation. Wind produces no emissions but has reliability issues. Geothermal has promise but is in the pilot stage. While the outlook for power generation a decade or two out is unclear, gas will likely play an increasing role in providing reliable baseload capacity and filling the growing demand for peaking capacity.

A fourth global influence considered in this essay is the financial and economic crisis. The recession has affected energy demand and prices across the world. The cost of developing gas fields, plants and pipelines can run to billions of dollars. After years of easy credit and low financing costs, interest costs have spiked and credit availability has shrunk, making it more difficult to refinance existing borrowings and fund new projects. Tighter financial markets do not appear so far, however, to have impeded any major gas developments in Australia.

Finally, security of gas supply is an important issue for all markets. This essay provides some perspectives on recent developments in the security of Australia's natural gas supply system.

E.1 Liquefied natural gas

Global LNG consumption has risen strongly over the past decade. From 2003 until 2008, when the recession flattened growth, LNG consumption was rising annually by around 7 per cent. The world's largest import customers are Japan and South Korea (figure E.2). Japan is a critical market for Australia: 79 per cent of Australia's LNG goes to Japan (supplying 17 per cent of its LNG demand).

Demand for LNG is linked to various factors. Japan, South Korea and Taiwan lack alternative sources of natural gas, and China has insufficient infrastructure to meet gas demand in coastal cities from domestic sources. In Europe, an increasing number of countries are seeking to diversify their sources of gas supply away from Russia.

While global LNG demand has eased in the recession, it is likely to regain strength over the medium term as existing importers add further re-gasification capacity and new countries become importers. In addition to the 18 countries that import LNG, a further 17 countries have import plants under construction or planned. In the Asia Pacific region, these include Malaysia, Singapore, Thailand, Indonesia, Chile and the Philippines (figure E.3).

Figure E.3
Countries importing liquefied natural gas, 2009

Key to LNG regasification terminals

- ● Operational
- ■ Under construction
- ▲ Planned or proposed

Source: EnergyQuest, based on International Energy Agency, *Natural gas market review*, Paris, 2009.

On the supply side, the largest LNG exporters are Qatar, Malaysia and Indonesia. According to BP, Australia was the world's sixth largest exporter in 2008, supplying around 9 per cent of global exports. In the current decade, production has increased from Qatar, Malaysia, Nigeria, Australia, Trinidad and Oman (figure E.4). Qatar is increasing its capacity enormously, from 30 million tonnes per year to 77 million tonnes per year by 2012. In the Asia Pacific region, two projects were scheduled to commence production in 2009—Sakhalin 2 in Russia and Tangguh in Indonesia.

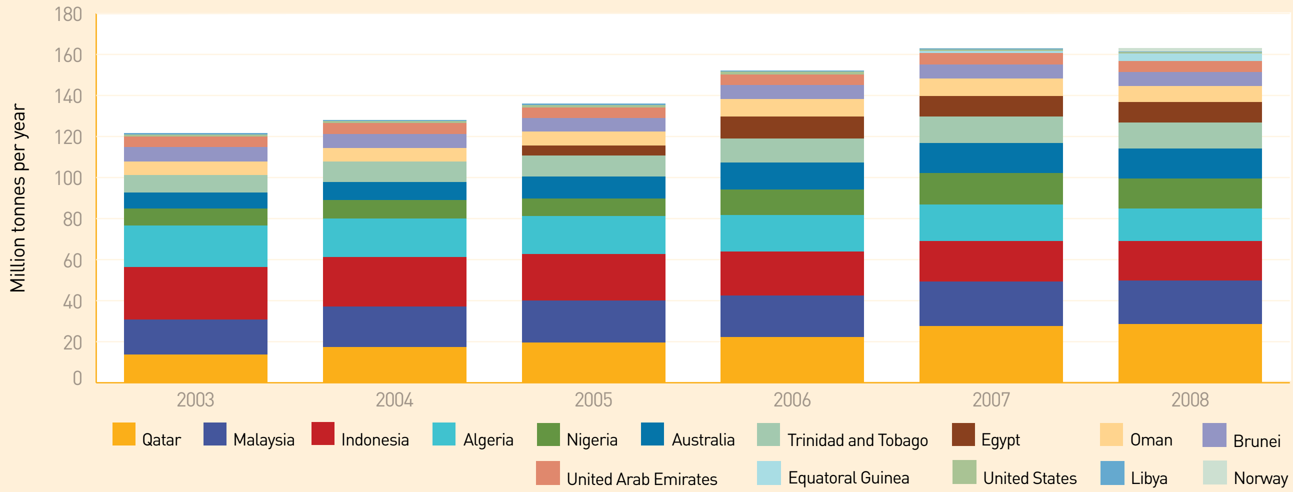
While Indonesia was the world's largest LNG producer until 2006, its annual exports have fallen from over 25 million tonnes early this decade to 19 million tonnes in 2008. This fall reflects reduced gas availability and the prioritisation of gas for domestic use.[1] Output from Tangguh will only partly offset the recent decline in Indonesian production.

There is the risk of a looming surplus of LNG over the next few years, due to the recession and increased capacity, particularly from Qatar. But LNG liquefaction projects take many years to build, and only five new projects have reached final investment decision since mid-2005. As the International Energy Agency noted:

> In the LNG sector, notwithstanding the massive increases in capacity that will be seen in the next few years from projects under construction, very few new projects have been sanctioned in recent years. Unless 2009 and 2010 see a number of new project approvals, there will be a dearth of new capacity in the period after 2012. Globally there is nearly twice as much regasification capacity operating or well under construction, compared to liquefaction capacity.[2]

1 J Stern, *Natural gas in Asia*, Oxford Institute for Energy Studies, Oxford, 2008.
2 International Energy Agency, *Natural gas market review*, Paris, 2009, p. 14.

Figure E.4
World exports of liquefied natural gas



Source: BP, *Statistical review of world energy 2009*, London, 2009.

It questioned where the next generation of LNG projects will come from after 2012. Many developers think the answer is Australia. While Australia is only one of a number of countries proposing new liquefaction projects, it has the most ambitious expansion plans of any country.

E.1.1 Liquefied natural gas prices

Interest in further developing Australian LNG export projects is driven by Australia's abundant gas resources —over 200 000 PJ, one of the largest endowments in the Asia Pacific region—as well as disparities between domestic and international gas prices. While international gas prices have trended significantly higher over the past decade (figure E.5), Australian domestic gas prices have been relatively low. Until recently, upstream prices were around \$2–3 per gigajoule in Western Australia and \$3–4 per gigajoule on the east coast. In contrast, US gas prices (an indicator of gas prices globally) peaked at over US\$12 per gigajoule in mid–2008.

Like domestic gas, most LNG is sold under long term contracts (although the spot market is growing). But unlike domestic gas, global gas prices have increasingly tended to settle around energy equivalent oil prices. An energy equivalent price for gas is 17.2 per cent of the oil price, based on the energy composition of LNG compared with a barrel of oil. At an oil price of US\$70 per barrel, an energy equivalent price for gas would be US\$12.04 per million British thermal units (US\$11.35 per gigajoule).

Australian LNG export prices are linked to Asian oil prices, and are increasingly quoted on a straight percentage basis—typically, a percentage of average Japanese oil import prices (known as the 'Japanese crude cocktail'). Over the past year or two some long term LNG contracts have been written at oil parity and others at close to oil parity.

To compare this with Australian gas prices, it is necessary to account for the costs of liquefaction and freight. After adjusting for these costs, the equivalent Australian gas price received by producers at the gas field would still be significantly higher than historical Western Australian domestic gas prices or current east coast prices.

International gas prices have fallen since the peaks of 2008, with US prices falling below US\$4 per gigajoule in 2009—around one third of oil parity, based on an oil price of US\$70 per barrel. The proponents of Australian LNG projects consider, however, there will be significant commercial benefits over the longer term from exporting Australian gas as LNG.

E.1.2 Australian liquefied natural gas developments

Notwithstanding the recent easing in LNG demand, oil and gas companies are committing to spend billions of dollars on new Australian projects. The Gorgon project in Western Australia alone could involve a $50 billion investment.[3] Also on the west coast, the 4.3 million tonne per year Pluto project is under construction and set to become Australia's third operational LNG project. Pluto is due for completion in 2010 and will supply the major Japanese buyers Tokyo Gas and Kansai Electric. Other potential LNG projects in north west Australia are at an advanced stage of planning, including the Ichthys project in the Browse Basin, which is aiming to reach final investment decision (FID) by the end of 2010 (table E.1).

In Queensland, four LNG projects reliant on CSG are at an advanced stage of planning. Most are at the front end engineering and design (FEED) stage and aiming for FID by the end of 2010. Section E.2 considers the Queensland proposals in more detail.

Nationally, these projects have a combined potential annual capacity of 47–72 million tonnes. Over 20 million tonnes per year from these projects is already committed to buyers—a similar magnitude to Australia's total current LNG capacity.

There are further proposed projects: additional trains for the Pluto project; the Browse Basin LNG project operated by Woodside; a floating LNG development on the Prelude field in the Browse Basin (Shell); the project based on the Sunrise field between Australia and Timor Leste (Woodside); a project based on the massive Scarborough field in the Carnarvon Basin (BHP Billiton); and another CSG–LNG project in Queensland (Shell).

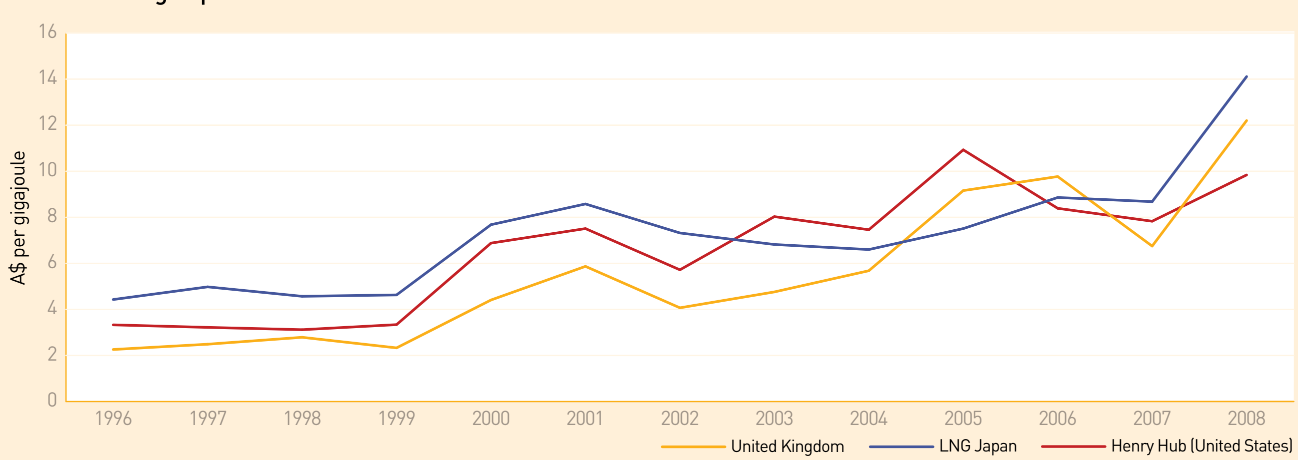
At the time of writing, the global financial crisis and recession have not affected the momentum behind these projects—notwithstanding higher financing costs and reduced funding availability. It can take five years to build an LNG project, and companies are looking through the current downturn to the middle of the next decade.

E.1.3 Domestic implications

Australia produces almost as much gas for LNG as for domestic use. Even if only some of the proposed LNG projects proceed, LNG will increasingly drive domestic markets.

Figure E.5

International gas prices



Source: EnergyQuest, based on BP, *Statistical review of world energy 2009*, London, 2009.

3 Hon M Ferguson, Minister for Resources and Energy (Queensland), Speech to Queensland Resources Council, 20 July 2009, http://minister.ret.gov.au/TheHonMartinFergusonMP/Pages/QUEENSLANDRESOURCESCOUNCIL.aspx.

Table E.1 Near term potential of Australian liquefied natural gas projects

PROJECT	OPERATOR	LOCATION	SCALE (MILLION TONNES PER YEAR)	OFFTAKE AGREEMENTS	STATUS AT JULY 2009	PLANNED START
WESTERN AUSTRALIA						
Pluto	Woodside	Carnarvon Basin	4.3	✓	Over 70% complete	2010
Gorgon	Chevron	Carnarvon Basin	15.0	✓	In FEED	
Wheatstone	Chevron	Carnarvon Basin	9.0		In FEED	
WESTERN AUSTRALIA / NORTHERN TERRITORY						
Ichthys	INPEX	Browse Basin	8.4		In FEED	
QUEENSLAND						
Fisherman's Landing LNG	LNG Ltd and Arrow Energy	Gladstone	1.5–3.0	✓	In FEED	Late 2012
Queensland Curtis LNG	BG Group	Gladstone	7.4–12.0	✓	In FEED	2014
Gladstone LNG	Petronas and Santos	Gladstone	3.5–10.0	✓	In FEED	2014
Australia Pacific LNG	ConocoPhillips and Origin Energy	Gladstone	3.5–14.0		Pre-FEED	2014 or 2015

FEED, front end engineering and design.

Source: EnergyQuest.

Western Australia has substantial gas resources available for LNG (over 100 000 petajoules) but a shortage of gas for domestic use. In 2007 this led to gas prices for new long term domestic contracts increasing from around \$2–3 per gigajoule to over \$7 per gigajoule. Higher prices have been attributed to a range of factors:

- Strong global demand significantly raised international energy prices, making LNG exports an attractive alternative to domestic sales.
- Historically low domestic prices created little incentive to explore for new sources of domestic gas supply.
- Western Australia's resources boom pushed up input prices generally. Development costs for gas fields have also increased for both LNG and domestic gas. In part, this is because new fields tend to be located in deeper water and are more expensive to develop.
- Western Australia has a limited number of fields producing domestic gas. Most recently discovered offshore fields are large enough to have LNG potential. The relative shortage of gas fields that are unsuitable for LNG makes domestic gas users relatively dependent on LNG projects.
- Much of Western Australia's domestic market relies on a single transmission pipeline—the Dampier to Bunbury Pipeline (see below).

The Western Australian Government is undertaking measures in response to domestic supply issues. One issue is that the gas specification for the Dampier to Bunbury Pipeline is narrower than the Australian standard, which has prevented development of the Macedon field.[4] The government plans to introduce legislation to broaden the specification.[5] Under the proposal, gas producers that supply at the broader specification will compensate pipeline owners and large consumers for increased costs to their operations, as part of their commercial negotiations. Suppliers providing gas at the broader specification will also pay a levy to fund the replacement of some pre-1980 gas appliances that may have safety issues. The broader gas specification and appliance prohibition will apply from 1 January 2012.

4 Gas from the Macedon field does not meet the pipeline's current specification.

5 Hon. P Collier, Minister for Energy and Training (Western Australia), 'State Government opens door to greater domestic gas supplies', Media release, Perth, 27 December 2008.

There has also been concern about the quantity of gas held under retention leases for discoveries that are not currently commercial. The leases allow successful explorers to retain rights over a gas field until it becomes commercial. Australia's Department of Resources, Energy and Tourism is reviewing the retention lease system.[6] The Western Australian Government has also released and promoted onshore exploration acreage considered to have gas potential, and has reduced the royalty rate for onshore tight gas from 10 per cent to 5 per cent.[7]

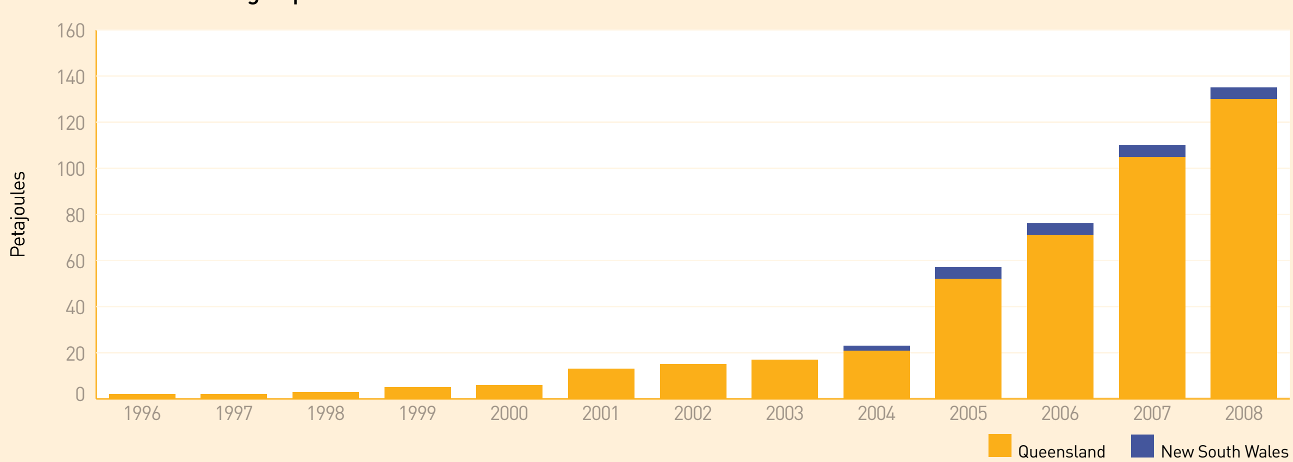
The development of significant volumes of domestic gas depends (at least in part), however, on the early development of LNG projects. In 2006 the Western Australian Government introduced a policy to reserve gas from LNG projects for domestic purposes. Under the policy, the government negotiates with project proponents to include a domestic gas supply commitment as a condition of land access for processing facilities. The state aims to secure domestic gas commitments up to the equivalent of 15 per cent of LNG production from each project. Commitments have been made in relation to the Gorgon, Pluto and Wheatstone projects. The price of gas sold into the domestic market is to be determined through commercial arrangements between gas buyers and sellers. The prices are likely to be comparable to the returns that gas producers can obtain from LNG.

One risk mitigation approach that some major gas buyers are starting to adopt is to move up the supply chain and participate directly in gas field exploration and development. This approach provides a hedge against gas supply and price risk. It increasingly occurs on the east coast, where major gas and electricity utilities have acquired interests in gas exploration and development. In Western Australia, Alcoa has taken interests in onshore exploration.

E.2 Coal seam gas

The fastest growing source of gas supply in eastern Australia is CSG, with production having grown from around 17 PJ to 135 PJ in the five years to 2008. It now supplies around 21 per cent of the east coast gas market (figure E.6). Around 96 per cent of east coast CSG production is sourced from Queensland, with the remainder from the Sydney Basin.[8]

Figure E.6
Australian coal seam gas production

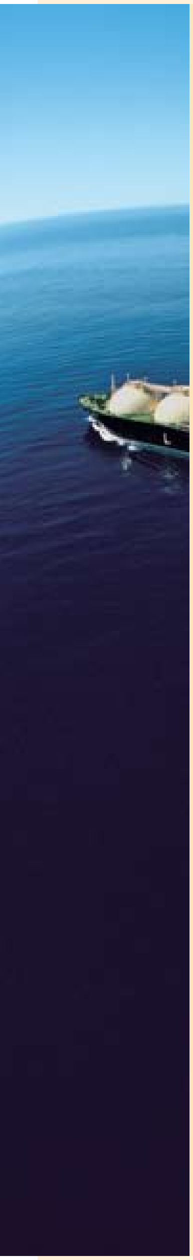


Source: EnergyQuest.

6 Hon. M Ferguson, Minister for Resources and Energy (Australian Government), 'Retention lease discussion paper released', Media release, Canberra, 12 June 2009.

7 Tight gas is gas with low flow rates due to low reservoir permeability. Such gas is less commercially viable than gas from highly productive reservoirs.

8 As well as CSG activity in Queensland and New South Wales, interest in unconventional gas and increased recovery from existing fields is increasing elsewhere in Australia. In 2008 Santos identified 6900 PJ (gross) of contingent resources in the South Australian Moomba and Big Lake fields. This substantial gas resource could be commercialised at somewhat higher than current gas prices. Lakes Oil is having success with tight gas onshore in Victoria. Tight gas reservoirs onshore in Western Australia are also being actively assessed.



Box E.1 What is coal seam gas?

Like conventional natural gas, coal seam gas (CSG) is mostly methane but may also contain trace elements of carbon dioxide and/or nitrogen. While CSG is essentially transported, sold and used in the same way as conventional gas, the geology differs (table E.2). In particular, CSG is produced from coal deposits permeated with methane rather than sandstone reservoirs.

Coal seam gas is either biogenic or thermogenic in origin. Biogenic methane is generated from bacteria in organic matter in coal. Biogenic processes occur at depths of up to 1 kilometre. Thermogenic methane forms when heat and pressure transform organic matter in coal into methane. Thermogenic methane is generally found at greater depths than biogenic methane is found. Queensland basins have biogenic gas, thermogenic gas and mixed gases.

The natural fractures in coal create a large internal surface area that can hold larger volumes of gas than conventional sandstone reservoirs hold. A cubic metre of coal can contain six or seven times the volume of natural gas that exists in a cubic metre of a conventional reservoir.

The coal formation process generates methane, carbon dioxide and water. The large quantities of methane produced during the formation of the high rank bituminous and anthracite coals generally flush away most of the carbon dioxide. The bituminous coals of the Sydney and Bowen basins typically contain gas consisting of over 95 per cent methane, with smaller quantities of carbon dioxide, nitrogen and inert gases.

Table E.2 Conventional and coal seam gas

CONVENTIONAL NATURAL GAS	COAL SEAM GAS
Gas is generated in coals or shales at depth.	Coal seams are both the source and the reservoir.
Conditions must be right to generate gas and expel it from the source rock.	Methane is generated as coals are buried, heated and compressed.
Gas must migrate to a suitable structural trap in a suitable reservoir where it is stored in the pore spaces between the grains of the rock.	Gas is adsorbed as a thin film on the surface of the coal, and is held there by water pressure. No structural trap is required.
Natural pressure drives the gas to the surface.	The gas is liberated by removing water from the seam. The gas desorbs and flows to the surface.

Source: Origin Energy/EnergyQuest, *Australian coal seam gas 2008: CSG meets LNG*, Adelaide, 2008

Management of CSG production is more difficult than management of conventional gas production. While production from conventional gas wells can usually be shut in and then recommenced, CSG wells generally cannot be shut in without repeating the entire dewatering process. There are, however, 'free flow' holes in which the gas can flow freely without the need for further pumping of water.

From a commercial point of view, CSG requires considerably more drilled wells than conventional gas does to deliver comparable quantities of gas. While the cost per well is much lower for CSG, conventional fields also may contain high value oil or liquids that increase their potential economic value, which is not the case with CSG. Conversely, CSG has the advantage of being onshore and, in the majority of cases, relatively close to destination markets.

Certified proved and probable CSG reserves are increasing even faster than production rates—from 3176 PJ at the end of 2004 to 17 599 PJ in May 2009. Most reserves are in Queensland, but there is also significant growth in New South Wales (figure E.7). There are also substantial volumes of higher risk possible reserves (24 566 PJ) and contingent resources (32 319 PJ). Table E.3 summarises the details.[9]

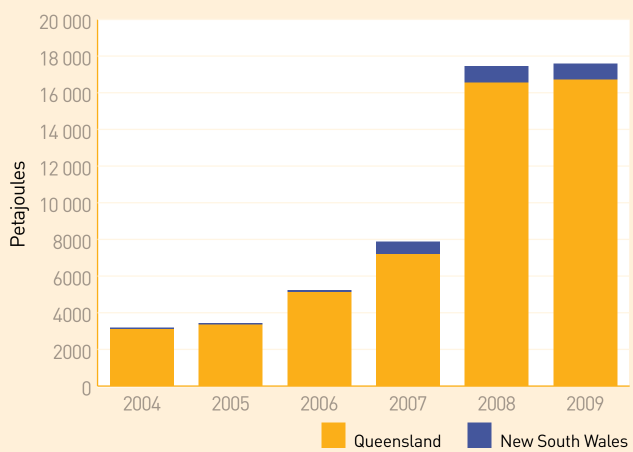
9 *Proved and probable reserves* (2P) are those that geoscience and engineering data indicate are more likely than not to be recoverable. There is at least a 50 per cent probability that the quantities recovered will equal or exceed the sum of estimated proved plus probable reserves. *Possible reserves* are those that are recoverable to a low degree of certainty (10 per cent confidence). There is relatively high risk associated with these reserves. *Proved plus probable plus possible reserves* are also known as 3P or P10. *Contingent resources* are those estimated, at a given date, to be potentially recoverable from known accumulations, but not considered to be commercially recoverable.

Table E.3 Gas reserves and resources—eastern Australia, May 2009

GAS BASIN	BOOKED RESERVES (PETAJOULES)		RESOURCES (PETAJOULES)		2008 PRODUCTION (PETAJOULES)
	PROVED AND PROBABLE	POSSIBLE	CONTINGENT	SPECULATIVE POTENTIAL	
Cooper (South Australia)	1 138		6900		140
Otway (Victoria)	1 416		205	2000–4000	110
Bass (Victoria)	306		420	Underexplored	16
Gippsland (Victoria)	5 637		3000	Possible upside	261
East Queensland conventional	144				19
Queensland CSG	16 708	22 141	29 094	Possible significant upside	130
New South Wales CSG	891	2 425	3225	Possible significant upside	5
Total	26 240	24 566	42 844		681

Source: EnergyQuest.

Figure E.7
Coal seam gas—proved and probable reserves



Source: EnergyQuest.

A key reason for the rapid growth in CSG reserves and resources has been a greater understanding of the nature of Queensland CSG, which has helped stakeholders identify the most suitable resources and understand how best to exploit them. There has been a continuing accumulation of geoscience and engineering data from producing fields and from the large number of wells being drilled. Around 600 new wells were drilled in 2008.

In addition, higher gas price assumptions play a role. Estimates of reserves and resources are sensitive to assumptions about future gas prices. The higher the price, the larger is the resource base that can be commercialised. In particular, the bookings of contingent resources are generally premised on the assumption that significantly higher gas prices can be achieved from LNG developments.

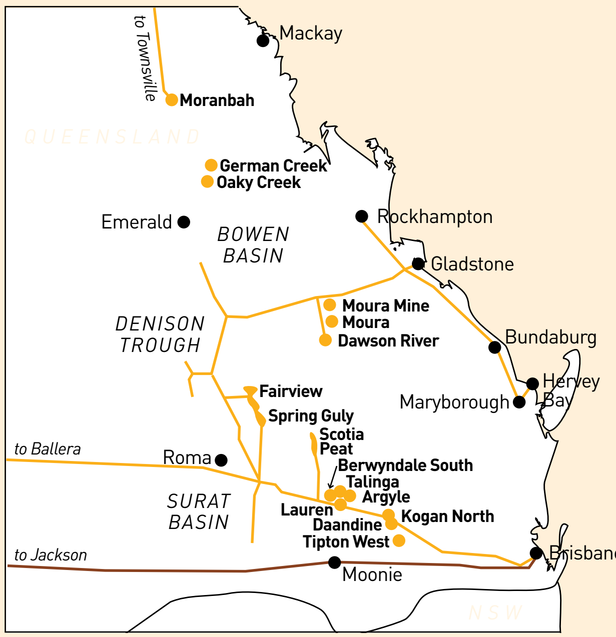
E.2.1 Australian regions that produce coal seam gas

Coal seam gas is produced from the bituminous coals of the Bowen and Sydney basins and the sub-bituminous coals of the Surat Basin. There is also exploration and early commercialisation in the Clarence-Morton, Gunnedah and Gloucester basins in New South Wales.

The major Queensland fields are shown in figure E.8. In 2008 Spring Gully had the largest production (36 PJ), followed by Berwyndale South (27 PJ) and Fairview (22 PJ). Spring Gully and Fairview are in an area known as the Comet Ridge. Berwyndale South is on the Undulla Nose.

Figure E.8

Coal seam gas fields—Queensland



Gas fields

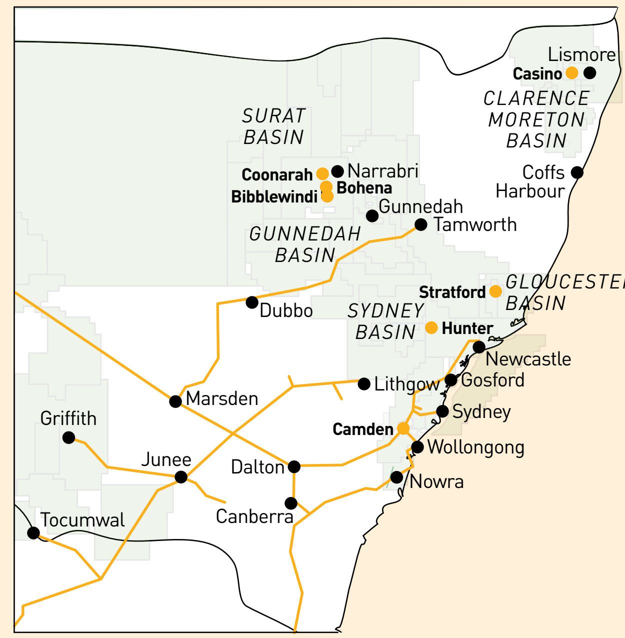
Gas pipeline

Oil pipeline

Source: EnergyQuest.

Figure E.9

Coal seam gas projects—New South Wales



Gas project

Gas pipeline

Permit licence or application area

Source: EnergyQuest.

Spring Gully (operated by Origin Energy) has contracts with Queensland customers and with AGL Energy for gas sales to the southern states. Origin Energy is building a 630 megawatt combined cycle power station to be supplied from Spring Gully and its Walloon acreage. The new station, located on the Darling Downs near Braemar, is expected to commence operating in 2010. Berwyndale South (operated by BG Group) commenced production in 2006 and supplies various Queensland power stations. BG also has gas contracts with AGL, which has completed a pipeline from Berwyndale South to Wallumbilla, to join with the South West Queensland and QSN Link pipelines to supply gas to the southern states.

Fairview (operated by Santos) has contracts with Queensland customers and also with Origin Energy for supply to AGL Energy for transport to the southern states.

Arrow Energy operates four producing fields:

> Moranbah (operated by Arrow Energy in joint venture with AGL Energy) commenced production in 2004 and supplies gas to the Townsville Power Station.

> Kogan North commenced production in 2006. Gas from the field is contracted to CS Energy for the Swanbank E Power Station.

> Daandine and Tipton West commenced production in 2007. Daandine supplies gas to a power station development, and Tipton West is contracted to Braemar Power.

There is also considerable interest in the CSG potential of the vast coal resources in New South Wales (figure E.9). Active CSG exploration and appraisal are continuing in northern New South Wales in the Gunnedah and Clarence-Morton basins. Santos considers the Gunnedah Basin may contain 40 000 PJ of recoverable gas. There has also been success in the Gloucester Basin, near Newcastle.

AGL Energy operates the Camden gas project in the Sydney Basin. This project, which is being expanded, produced just over 5 PJ in 2008.

Success with CSG in New South Wales would be significant, given the state's historical reliance on gas imported from interstate. The potential for New South Wales CSG will become clearer over the next few years.

E.2.2 Liquefied natural gas proposals

Until 2007 the focus of CSG development was on the Queensland domestic market, particularly on gas for power generation. Many early CSG contracts were for the Swanbank and Braemar power stations. In the past two years it became apparent that eastern Australia has considerably more CSG potential than can be commercialised for the domestic market alone. The supply curve for CSG is quite sensitive to price, and the CSG resource base that could be commercialised at LNG prices is significantly greater than could be developed at historic east coast prices. This has led to a shift in focus to the LNG market.

Four major LNG projects are proposed for Gladstone in Queensland (totalling 39 million tonnes per year). In 2007 Santos and Arrow Energy announced LNG development plans. Queensland Gas Company (later acquired by BG Group) and Origin Energy followed suit in 2008. (Table E.1 summarises details.) There are also smaller proposals.

While these plans were originally greeted with scepticism in Australia, they offered opportunities to major international LNG companies looking for substantial gas resources in the Asia Pacific region (the largest and fastest growing LNG market in the world), with low barriers to entry and low exploration risk. Accordingly, the Australian proponents were joined in 2008 by major international companies Petronas, Shell, BG Group and ConocoPhillips. In total, these entities spent around $20 billion to acquire CSG interests.

- Origin Energy entered an alliance with ConocoPhillips to develop a four train LNG project with ultimate capacity of 16 million tonnes per year, requiring more than 25 000 PJ of gas over 30 years. As part of the transaction, ConocoPhillips acquired 50 per cent of Origin Energy's CSG interests.
- BG Group acquired Queensland Gas Company (which had acquired Sunshine Gas and Roma Petroleum). It has since also acquired Pure Energy, and is developing an LNG project with initial production capacity of 7.4 million tonnes of LNG a year. It is seeking approval for capacity of 12 million tonnes per year.
- Santos entered an alliance with Petronas to develop its proposed Gladstone LNG project, targeting up to 10 million tonnes per year. As part of the arrangement, Petronas acquired 40 per cent of Santos's CSG interests.
- Shell acquired a 30 per cent interest in Arrow Energy's CSG fields. Arrow Energy has agreed to supply sufficient gas for up to 3 million tonnes per year of LNG for the project proposed for Fisherman's Landing at Gladstone.

New entry has led to extensive industry consolidation over the 18 months to June 2009. As noted, Queensland Gas Company, Pure Energy, Sunshine Gas and Roma Petroleum are now all part of the BG Group. AGL Energy, Origin Energy and Arrow Energy have also acquired various interests. At the same time, total CSG reserves have grown significantly, and the interest in CSG has encouraged a flurry of interest in exploration and in new basins.

The entry of major international companies is a significant development, underlining their confidence in both the future demand for LNG and the quality of Queensland CSG resources. Notwithstanding the softening of immediate LNG demand, the four major LNG projects proposed for Gladstone are all pushing ahead (and with further interest from Shell and other companies). There is an increasing likelihood of LNG exports from Gladstone, with three of the four major projects at the FEED stage and having gas sale contracts in place. All four are aiming for FID by late 2010 (table E.1).

The degree of confidence has been highlighted by the decisions of Petronas and the Chinese company CNOOC to buy Australian CSG based LNG for the Malaysian and Chinese markets.

If all successful, these LNG projects could require 2750 PJ of gas per year—more than Australia's total current gas production of 1600 PJ per year—and CSG reserves of at least 55 000 PJ. Queensland's proved, probable and possible reserves in May 2009 stood at 38 849 PJ, with a further 29 094 PJ of contingent resources.

A number of challenges are associated with using CSG for LNG. There is no associated liquids production (which improves the economics of conventional LNG projects); the gas has lower energy content than that of conventional LNG; and the process of managing the CSG production profile to meet LNG production requirements is more complicated.

Water disposal and treatment is a particular issue and is becoming a significant cost. In 2007 Queensland CSG fields produced 12.5 billion litres of water. The quality of the water can vary from drinkable to highly saline. Water production is now around 22 billion litres and could grow to 250–480 billion litres per year if LNG development reaches annual production of 40 million tonnes.[10]

The CSG proposals are competing with conventional LNG projects proposed for Australia and Papua New Guinea, all involving large scale gas resources and experienced international LNG participants. A number of these competing projects are progressing quickly. Conventional LNG projects can also have various challenges, however, depending on the field. Some fields contain significant quantities of carbon dioxide. Others may have a low concentration of liquids, significant water depth, distance from shore or remoteness of location.

E.2.3 Implications for the domestic gas market

With four major east coast LNG projects aiming for FID by late 2010, there have been concerns that prices for new domestic gas contracts may rise close to international levels, as has occurred in Western Australia. There are some similarities between the Queensland and Western Australian market contexts. In each case:

- the LNG market is potentially larger than the domestic market
- the bulk of gas resources is owned by a small number of entities targeting LNG exports.

One important difference relates to the amount of 'ramp-up' gas likely to be produced by the east coast projects. LNG projects require substantial annual gas volumes of around 200 PJ per year for each train. In a conventional LNG project, this requirement may be met by six or eight gas development wells that would be drilled and then shut in until the plant is ready for commissioning. Providing the same gas volumes from CSG may require 500–700 wells, however, given the much lower flow rates per well. Drilling this number of wells may take a couple of years, rather than a few months. Each well then has to 'ramp up', first producing water and then increasing volumes of gas. This may take months for each well.

Once a CSG well is in production, it is generally difficult to shut it in without having to start the process again. The result is that substantial volumes of 'ramp up' gas are likely to be produced in the lead-up to the commissioning of Queensland's CSG-LNG projects. In the short to medium term, this is likely to mean that increased supplies of gas will be available at relatively low prices for domestic purposes such as power generation. There is evidence, however, that domestic buyers are already finding it difficult to secure long term gas supply commitments beyond the likely start-up times for LNG projects.[11]

10 M Helmuth, 'Developing Queensland's CSM and LNG industries: a Queensland Government perspective', Paper presented at the FutureGas Conference, Brisbane, 22 March 2009.

11 Rio Tinto, *Energy white paper submission*, 11 June 2009, www.ret.gov.au/energy/Documents/ewp/pdf/EWP%200102%20DP%20Submission%20-%20Rio%20Tinto.pdf.

While real prices may rise in the medium to longer term, this would likely increase gas supply for both LNG and domestic markets. Experience has been that higher gas prices lead to substantial increases in the volume of commercially viable CSG.

Any significant increase in demand (such as would occur from LNG exports) over the long term, however, is likely to raise production costs. In particular, the resources targeted for LNG projects are among the highest quality, and using these for LNG may force domestic use towards lower quality/higher cost reserves. This would put upward pressure on prices. The use of CSG for LNG will also tighten the gas demand-supply balance generally.

A number of features of east coast markets may cushion price impacts. Unlike Western Australia, the east coast has a number of gas basins, with greater diversity of supply. There is substantial exploration acreage with relatively low barriers to entry, and an extensive gas transmission network linking the producing basins.

E.3 Climate change policies

Climate change is a third global influence impacting on energy markets. While natural gas is a fossil fuel, it can produce large volumes of reliable baseload electricity with around half the greenhouse emissions of coal. Increased use of gas in electricity generation is likely, therefore, to form part of the suite of responses needed to shift economies to a lower carbon footprint. In particular, gas can play an important role as a transition fuel. Its increased use can avoid the locking in of higher emissions from coal fired generation, thereby buying more development time for other clean energy solutions to grow.

The Garnaut climate change review predicted the introduction of emissions trading would lead to an increased role for gas in power generation in Australia.[12] This would imply substantial increases in demand for natural gas. In 2007–08 Australia produced 30 terawatt hours of gas fired power, consuming 307 PJ of natural gas.[13] According to Australian Treasury estimates published in December 2008, gas fired power generation could increase to 60–64 terawatt hours by 2020 under the Garnaut scenarios. This would increase gas demand to 530–560 PJ—a doubling of current gas use in power generation.[14]

The Garnaut review also predicted greenhouse mitigation policies overseas would expand opportunities to export gas. It expected, however, that while gas use would continue to grow in absolute terms, its role may be constrained beyond 2020 as rising permit prices make renewable sources and coal with carbon capture and storage more competitive.

The International Energy Agency came to similar conclusions. It projected continued global growth in the longer term use of natural gas under carbon abatement scenarios—but at a slower rate than under business-as-usual conditions. The agency projected that if greenhouse gases are stabilised at 450 parts per million, gas demand would grow at an average rate of 0.9 per cent per year over the period to 2030—half the rate of growth under business-as-usual conditions.[15] A high carbon price would make low carbon generation more attractive than gas. Rising electricity prices in the residential sector would encourage energy efficiency and renewable investment, which reduce the use of fossil fuels.

These projections rely on assumptions about long term energy prices, carbon prices, the outcomes of future research and development, and costs of competing forms of energy—all of which are subject to considerable uncertainty. In particular, the long term economics and operational performance of carbon capture and storage (and of some renewable energy technologies) are not known with certainty. In contrast, gas has a proven record as a reliable supplier of relatively clean baseload power on a large scale.

12 R Garnaut, *The Garnaut climate change review: final report*, Canberra, October 2008, p. 498.

13 ESAA, *Electricity gas Australia*, Melbourne, 2009.

14 MMA, *Impacts of the Carbon Pollution Reduction Scheme on Australia's electricity markets*, Report to Federal Treasury, Melbourne, December 2008. The spread of outcomes reflects different emissions target scenarios. See R Garnaut, *The Garnaut climate change review: final report*, Canberra, October 2008, p. 296.

15 International Energy Agency, *World energy outlook 2008*, Paris, 2008.

Governments in Australia and overseas have tended to focus on the development of renewables and low emission coal technologies, rather than gas, as preferred long term options for reducing greenhouse emissions.[16] The 2009 Australian Government budget, for example, allocated $4.5 billion to support the growth of clean energy generation and new technologies, including $2.4 billion for clean coal technologies and $1.3 billion for solar technology.[17]

Consistent with this, the Australian Government has expanded the renewable energy target. The expanded scheme aims to increase renewable energy generation to 20 per cent of all generation by 2020 (an increase from the current level of around 20 terawatt hours to 60 terawatt hours). The Australian Treasury noted that one likely effect of the expanded scheme would be to 'crowd out' gas fired generation.[18]

In its 2008 report to Treasury, McLennan Magasanick Associates estimated that in the absence of mandated renewables, there would be 62 terrawatt hours of gas fired generation by 2020 under the proposed Carbon Pollution Reduction Scheme (assuming a 5 per cent targeted reduction in emissions from 2000 levels). With mandated renewables, gas fired generation would be around 59 terrawatt hours, regardless of whether the targeted reduction in emissions is 5 or 15 per cent from 2000 levels.

The future role of gas depends on the prices of gas, coal and carbon. For existing power stations, coal is still much cheaper than gas, ranging from less than $0.50 per gigajoule in Victoria to $1.50–2.00 in New South Wales and Queensland.[19] If ramp-up gas from LNG projects keeps gas prices low on the east coast, then gas could be competitive for power generation. Likely higher gas prices once LNG projects commence, however, would make gas less competitive.

Higher carbon prices favour gas over coal but give renewables an advantage. Some major gas users—such as aluminium and cement—are also emissions intensive, and their treatment under the Carbon Pollution Reduction Scheme will affect gas demand.

Gas is likely to play an important role under climate change policies in complementing intermittent renewable electricity generation. Wind generation—the likely primary renewable technology to 2020—has intermittent output and must be backed up by other generation. Open cycle gas plants can respond quickly when there is insufficient wind generation, but any new plant is likely to operate at relatively low capacity factors. There will also be an increased need for gas transmission and storage to provide gas at short notice.

In addition to the impacts of climate change policies on gas use for electricity generation, there may be implications for the LNG industry. In Asia, climate policies are likely to increase the demand for LNG (and LNG prices) as a cleaner alternative to coal for power generation. At the same time, LNG production creates greenhouse emissions that may be priced under the Carbon Pollution Reduction Scheme. Some gas reservoirs being proposed for Australian LNG projects contain significant volumes of carbon dioxide, and the process of liquefaction also emits carbon dioxide. The proponents have plans to manage these emissions, but have also sought relief under the proposed Carbon Pollution Reduction Scheme.

E.4 Global financial crisis

The global financial and economic crisis is a fourth global influence potentially affecting Australian gas markets. Overseas, the recession has led to a significant easing in the demand for gas. Australian LNG exports have increased against this trend, with a fifth train on the North West Shelf recently becoming

16 J Snyder, 'Natural gas companies challenge coal industry on climate change bill', *The Hill*, 29 July 2009, http://thehill.com/business--lobby/natural-gas-companies-challenge-coal-industry-on-climate-change-bill-2009-07-29.html.

17 Hon. M Ferguson, Minister for Resources and Energy (Australian Government), Speech to Queensland Resources Council, Rockhampton, 20 July 2009, http://minister.ret.gov.au/TheHonMartinFergusonMP/Pages/QUEENSLANDRESOURCESCOUNCIL.aspx.

18 Australian Treasury, *Australia's low pollution future: the economics of climate change mitigation*, Canberra, October 2008, p. 181.

19 ACIL Tasman, *Fuel resources, new entry and generation costs in the NEM*, Report to AEMO, Melbourne, April 2009.

fully operational. Domestically, the downturn does not appear to have significantly affected east coast gas consumption.

Billions of dollars are needed to fund the suite of proposed Australian upstream developments, processing facilities and infrastructure. So far, the signs are that companies have been tightening their belts but not deferring or cancelling gas developments in the context of lower revenues and tighter financial markets.

Companies typically finance development projects from:

> cash flow
> asset sales and/or cuts to exploration
> debt raising
> equity raising.

While many Australian upstream oil and gas companies have reasonably strong balance sheets, the recent fall in commodity prices has reduced their capacity to fund new developments. This has led a number of upstream companies to sell non-core assets, look for partners and reduce exploration spending.

Generally, the credit ratings of oil and gas companies operating in Australia have been largely unaffected by the crisis, although Standard and Poor's outlook for Woodside's long term A– rating was revised from stable to negative. The agency said this revision reflected the fall in oil prices and ongoing funding requirements for Woodside's Pluto LNG project.

In relation to debt raising, companies typically seek bank funding, issue bonds or seek project financing. Generally, the global financial crisis has increased the cost of debt and reduced its availability. In particular:

> banks have become more inward focused as they give priority to resolving their own financial positions. This behaviour has included withdrawal from some offshore markets, including Australia.
> banks have less capital and are using it cautiously
> banks are repricing risk across the credit curve, reflecting increases in their own funding costs
> banks have been giving priority to supporting key existing customers and attractive new clients
> more banks are needed to fund any one transaction
> borrowing terms have been reduced, typically to three years, and interest costs have more than doubled.[20]

Companies operating in Australia's gas sector have nonetheless been able to raise debt. In May 2009 Woodside announced it had executed a US$1.1 billion syndicated loan facility with 26 banks—a large number. This followed a US$1 billion issue in the US bond market in February 2009. Interest spreads, however, have typically been around 400 basis points over the five year swap rate, giving an overall funding cost of 9–10 per cent.

AGL Energy has successfully refinanced its 2009 and 2010 debt maturity obligations of $800 million but at a cost of 280 basis points over the relevant base rates, and requiring the participation of Australia's four major banks and 13 offshore banks.

Pipeline companies have generally been more negatively affected than upstream gas companies by higher borrowing costs and reduced financing availability. In particular, the higher gearing of pipeline companies has made it more difficult for them to obtain finance for new projects at an acceptable cost. A proposed expansion of the South West Queensland Pipeline to provide capacity for Origin Energy, for example, was subject to obtaining the necessary funding on acceptable commercial terms. The availability of project finance is also reported to have shrunk. A year ago industry found it relatively easy to source project finance for a gas fired power station project, but this is no longer the case.

The other financing option for companies is to raise equity. Santos raised $3 billion of new equity from institutional and retail investors to fund its commitments to the Papua New Guinea LNG project and to redeem a previous issue. This was successful but was made at a 27 per cent discount to the previous share closing price.

20 Based on EnergyQuest discussions with market participants. See also: S3 Advisory, *Financing of future energy sector investments in Australia: the potential effects of the Carbon Pollution Reduction Scheme and Renewable Energy Target*, Report prepared for the AEMC, Sydney, December 2008; and I Little, *Envestra open briefing*, Adelaide, 8 July 2009.

Peter Hendrie (Getty Images/Photographer's Choice)

There has also been an increase in the number of assets offered for sale. Companies are reviewing their portfolios and disposing of non-core assets to fund core projects. While there have been some sales by distressed buyers, however, there has not been a flood of properties onto the market, and competition has been keen for those that have come up for sale.

Generally, financing is much more difficult and expensive than it was before 2007, but this has not yet stopped any major gas projects. Financing conditions in the gas sector appear to be mostly more favourable than, for example, conditions for refinancing coal fired power stations.

E.5 Security of gas supply

Security of gas supply is a critical issue globally and one of the key drivers of LNG demand—particularly in Europe, which depends on Russian gas supplies.

Australia's Department of Resources, Energy and Tourism recently reviewed Australia's natural gas security.[21] It assessed security as being only 'moderate' through to 2023 on three criteria: adequacy, affordability and reliability.[22] It found affordability to be currently 'high', but with the potential to fall to 'low' by 2018. The department assessed the current adequacy of natural gas supplies readily available for domestic consumption as 'moderate' on the east coast but 'low' in Western Australia.

With only two major gas producing facilities and one major pipeline to Perth, Western Australia is vulnerable to gas supply disruptions. The structural shortage of domestic gas in Western Australia was exacerbated by a pipeline rupture and fire at Varanus Island on 3 June 2008, which curtailed 30 per cent of the state's gas supply. Production was shut in from both the Harriett and John Brookes fields. Major gas and electricity customers—such as Alcoa, Newcrest, Iluka, Rio Tinto, BHP Billiton, Oxiana, Newmont, Alinta, Verve Wesfarmers and Burrup Fertilisers—were affected. There was substantial switching to North West Shelf gas (an extra 50 terajoules per day of output, which was limited by transmission pipeline capacity) and diesel, while major gas users brought forward maintenance. The Western Australian Government also recommissioned the coal fired Muja AB power station at Collie, freeing up 75 terajoules per day of gas supply for other users. A total 150 terajoules per day of additional gas was sourced, including gas surplus to requirements or capable of being freed up through use of diesel.

The Western Australian Treasury estimated the crisis cost the state economy $2 billion. The Reserve Bank of Australia estimated a reduction in state economic output of 3 per cent for the duration of the incident, and a reduction in Australian gross domestic product growth of 0.25 per cent in the June and September quarters of 2008.[23] It has taken 12 months to repair the Varanus Island facilities and return to pre-incident production rates. The Western Australian Government is reviewing the security of the state's gas supplies.

The east coast is now much less vulnerable to supply disruptions than is the west coast. East coast gas markets have continued to evolve rapidly, with a range of new supply sources. Historically, most east coast gas was supplied from two sources: the Gippsland Basin in offshore Victoria and the Cooper Basin in north east South Australia. The basins are still important, with Gippsland supplying 37 per cent of east coast gas in 2008 and the Cooper Basin supplying 20 per cent. East coast supply is now more diversified, however, with almost 20 per cent of east coast gas supplied from the Otway and Bass basins in offshore Victoria and 23 per cent supplied from Queensland CSG fields.

The east coast transmission pipeline system also continues to expand. Sydney, Melbourne, Adelaide and Canberra are now each served by transmission pipelines connecting multiple gas basins. Until early 2009 there was no pipeline between Queensland and the southern states, but this has now been rectified

21 Department of Resources, Energy and Tourism (Australian Government), *National energy security assessment*, Canberra, 2009.

22 The possible assessments are 'high', 'moderate' and 'low'.

23 Senate Standing Committee on Economics (Australian Senate), *Matters relating to the gas explosion at Varanus Island, Western Australia*, Canberra, 2008.

with the completion of the QSN Link from Ballera in Queensland to Moomba in South Australia. The QSN Link and the associated South West Queensland Pipeline are also being upgraded. Stage 1 of the South West Queensland Pipeline expansion is fully contracted from 2009 at up to 168 terajoules per day. AGL Energy has exercised an option for a stage 2 expansion, with gas deliveries commencing by 1 January 2013. This will take capacity to 220 terajoules per day. Origin Energy subsequently committed to a transportation agreement that will underpin an increase in capacity to 380 terajoules per day. This will enable Origin Energy to transport its CSG to southern markets. These arrangements will make the South West Queensland Pipeline/QSN Link one of Australia's largest gas transmission pipeline systems.

E.6 Conclusion

Australia is becoming a gas supplier of international significance on the back of its rapidly expanding resource base. It is now among the top 10 nations in terms of gas reserves and resources—with over 200 000 PJ—and in the next decade will likely become a major international producer. A significant driver has been gas price expectations. The Australian experience shows gas supply is highly price elastic. Rising price expectations are encouraging major investment in exploration and infrastructure.

The development of LNG will potentially benefit Australia's terms of trade, economic growth and employment. A significant benefit may be the buffer that LNG can provide against our declining oil production. Australia is relatively oil intensive by international standards.[24] Crude oil is Australia's largest import, followed by refined petroleum products.[25] Australia's self-sufficiency in oil and liquid fuels is 60 per cent and likely to decline further. This dependence exposes the economy to the risk of rising oil prices—something to which it has been relatively immune since the discovery of oil in the 1950s.

There are options for reducing this exposure, including increasing the efficiency of oil use and the development of liquid fuels from Australia's bountiful resources of shale and coal. That LNG development plans are progressing rapidly and have not been greatly affected by the global financial crisis is a positive development in the context of declining oil production and relatively high oil prices by historical standards. Further gas development may be part of the menu for offsetting and reducing Australia's oil vulnerability. As discussed, LNG export prices are indexed to oil prices. While Australia's current LNG exports of almost $6 billion are only a fraction of our $33 billion oil imports, LNG growth can help offset oil imports and volatility in the terms of trade due to fluctuating oil prices.

The growth in Australia's gas resources can also provide environmental benefits. While there is great enthusiasm to develop renewables, gas is a proven lower emissions fuel. Despite relatively low domestic prices, Australian gas use still accounts for only 18 per cent of primary energy consumption—low by international standards, and the same as a decade ago.[26] Of the world's largest holders of gas reserves, only Norway makes less use of gas domestically than Australia. In the United States, gas comprises 26 per cent of primary energy consumption; in the United Kingdom, it is 40 per cent. In Japan, which does not have its own gas and relies on relatively expensive imports, gas has a similar share of the primary energy mix as it does in Australia. Indonesia, the world's largest coal exporter and a major oil producer, uses gas for 27 per cent of its energy mix.

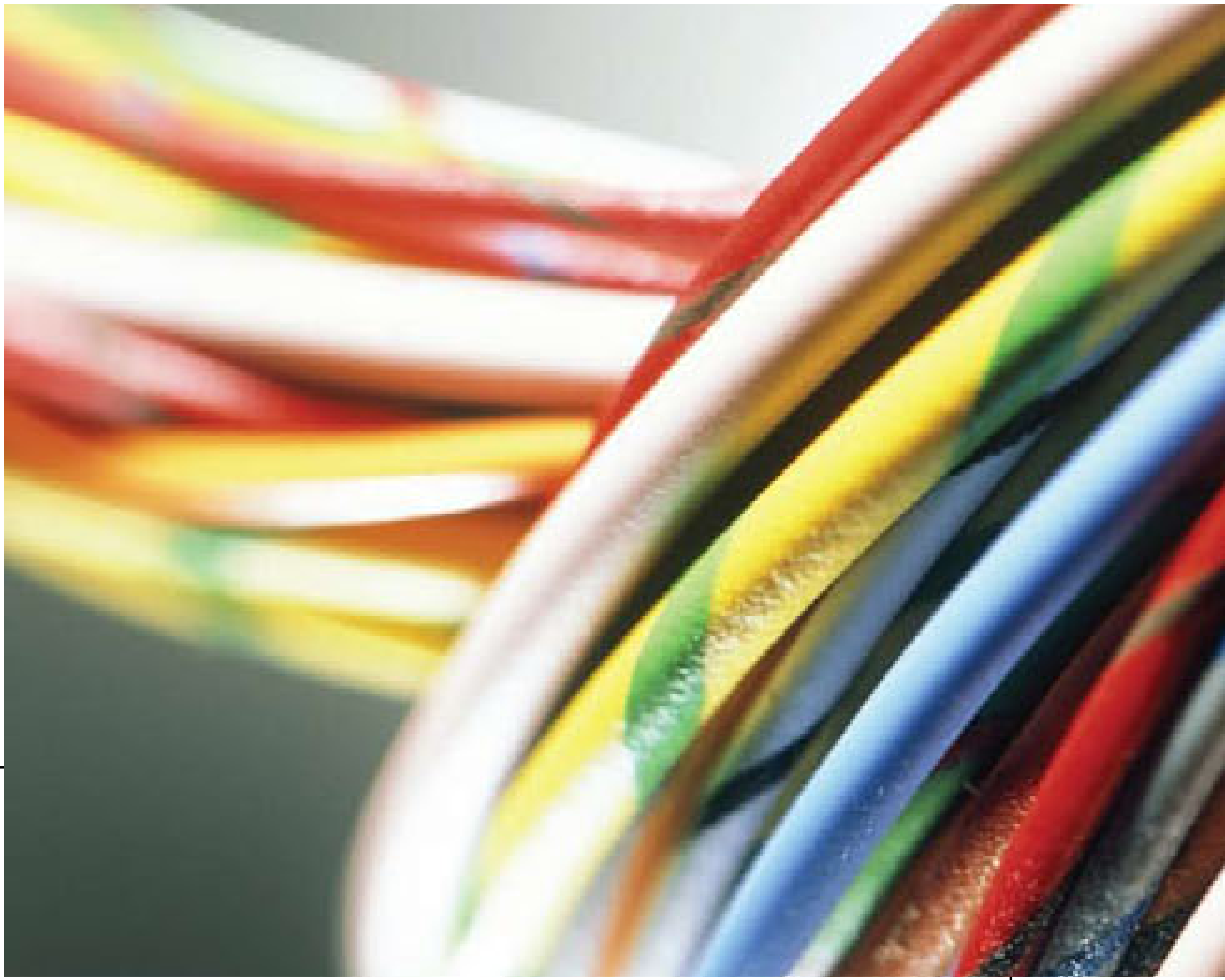
24 Geoscience Australia, Submission to the Senate Rural and Regional Affairs and Transport Committee Inquiry into Australia's Future Oil Supply and Alternative Transport Fuels, Canberra, February 2006; Queensland Energy Resources, *Australia's future transport fuel supply options*, Report by ACIL Tasman, EnergyQuest, Rurvin & Gertz and RARE Consulting, Brisbane, 2009.

25 Department of Foreign Affairs and Trade (Australian Government), *Composition of trade Australia 2008*, Canberra, 2009.

26 BP, *Statistical review of world energy*, London, 2009.

The increasing use of gas for domestic purposes—not only in power generation, but also in transport, business and retail applications—would reduce greenhouse emissions and deliver environmental and economic benefits. While wholesale Australian gas prices may rise in real terms, they are likely to remain relatively low compared with prices in gas importing countries.

The world wants and understands the value of Australian gas. The timing may be right for Australian gas to assume a more significant role at home as well as contributing to the energy needs of Asia.



PART TWO
ELECTRICITY

Electricity is a form of energy that is transported along a conductor such as metal wire. Although it cannot be stored economically, it is readily converted to other forms of energy, such as heat and light, and can be used to power electrical machines. These characteristics make it a convenient and versatile source of energy that has become essential to modern life.

ELECTRICITY

The supply of electricity begins with generation in power stations. Electricity generators are located usually near fuel sources such as coal mines, natural gas pipelines and hydroelectric water reservoirs. Most electricity customers, however, are located a long distance from electricity generators, in cities, towns and regional communities. The supply chain, therefore, requires networks to transport power from generators to customers. There are two types of network:

- high voltage transmission lines transport electricity from generators to distribution networks in metropolitan and regional areas
- low voltage distribution networks transport electricity from points along the transmission lines to customers in cities, towns and regional communities.

The supply chain is completed by retailers, which buy wholesale electricity and package it with transmission and distribution services for sale to residential, commercial and industrial customers.

Part two of this report provides a chapter-by-chapter survey of each link in the supply chain. Chapter 1 considers electricity generation in the National Electricity Market (NEM)—the wholesale market in which most electricity is traded in eastern and southern Australia. Chapter 2 considers activity in the wholesale market, and chapter 3 surveys the electricity derivatives markets that complement the wholesale market. Chapter 4 provides a survey of electricity markets in the non-NEM jurisdictions of Western Australia and the Northern Territory. Chapters 5 and 6 provide data on the electricity transmission and distribution sectors, and chapter 7 considers electricity retailing.

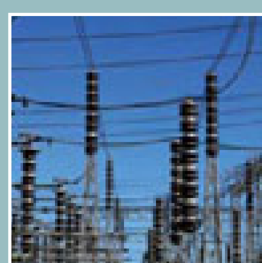
Electricity supply chain

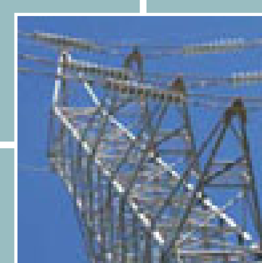
GENERATION

Electricity is generated at a power plant.

Transformers convert low voltage electricity to high voltage electricity for transport.

Substation transformers convert high voltage electricity to low voltage for distribution.



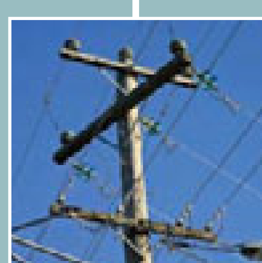


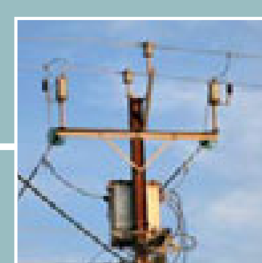
TRANSMISSION

Transmission lines carry high voltage electricity long distances.

DISTRIBUTION

Distribution lines carry low voltage electricity to customers.

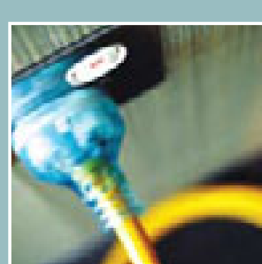




Transformers convert electricity to safe, usable levels.

CONSUMPTION

Electricity is used for lighting and heating, and to power appliances.



RETAIL

Retailers meter electricity use.

Image sources: Consumption, Jessica Shapiro (Fairfaxphotos); Other, Mark Wilson.

1 ELECTRICITY GENERATION

Mark Wilson

The supply of electricity begins with generation in power stations. This chapter provides a survey of electricity generation in the National Electricity Market, a wholesale market in which generators and retailers trade electricity in eastern and southern Australia. The six participating jurisdictions, physically linked by a transmission network, are Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania.

1 ELECTRICITY GENERATION

This chapter considers:

> electricity generation in the National Electricity Market, including geographic distribution and types of generation technology
> climate change policies and electricity generation
> the ownership of generation infrastructure
> new investment in generation infrastructure
> generation reliability in the National Electricity Market.

1.1 Electricity generation

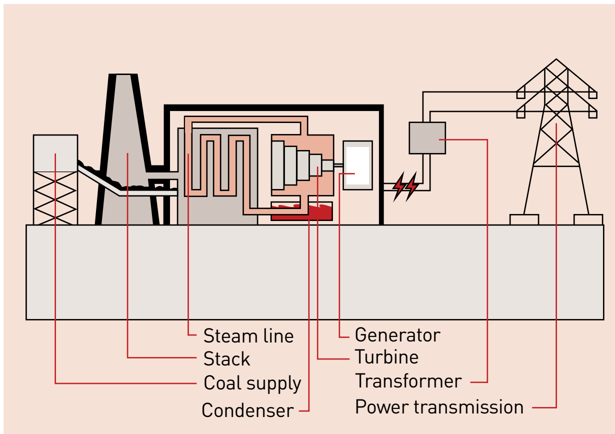
A generator creates electricity by using energy to turn a turbine, which makes large magnets spin inside coils of conducting wire. In Australia, electricity is mainly produced by burning fossil fuels (such as coal and gas) to create pressurised steam. The steam is forced through a turbine at high pressure to drive the generator. Other types of generator rely on the heat emitted through a nuclear reaction, or renewable energy sources such as the sun, wind, geothermal resources (hot rocks) or water flow to generate electricity. Figure 1.1 illustrates five types of electricity generation most commonly used in Australia: coal fired, open cycle gas fired, combined cycle gas fired, hydroelectric and wind.

The fuels that can be used to generate electricity each have distinct characteristics. Coal fired generation, for example, has a long start-up time (8–48 hours), while hydroelectric generation can start almost instantly. Lifecycle costs and greenhouse gas emissions also vary markedly with generator type.

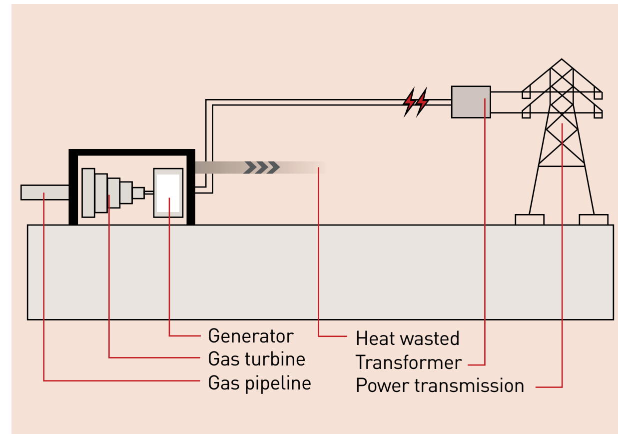
Figure 1.1

Electricity generation technologies

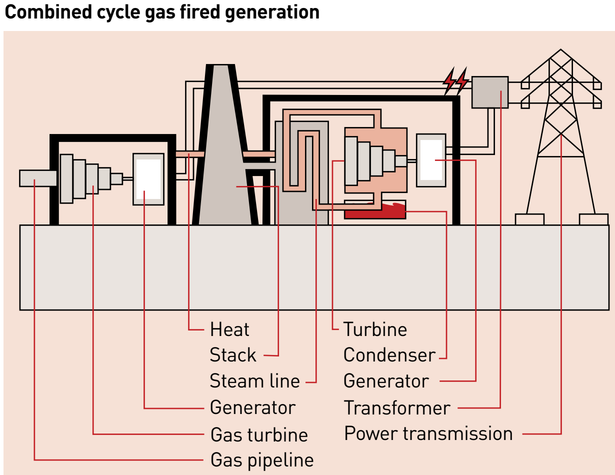
Coal fired generation



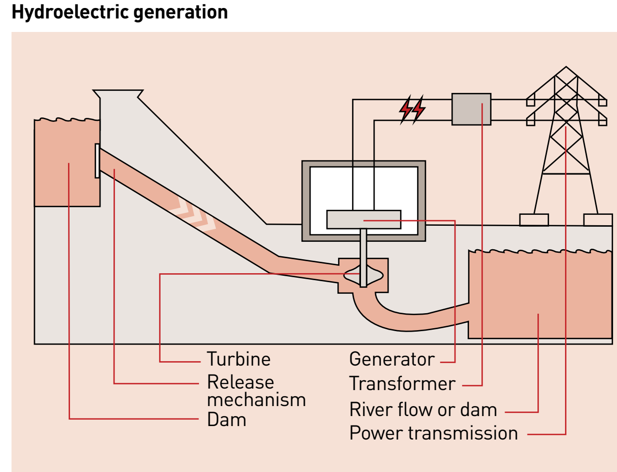
Open cycle gas fired generation



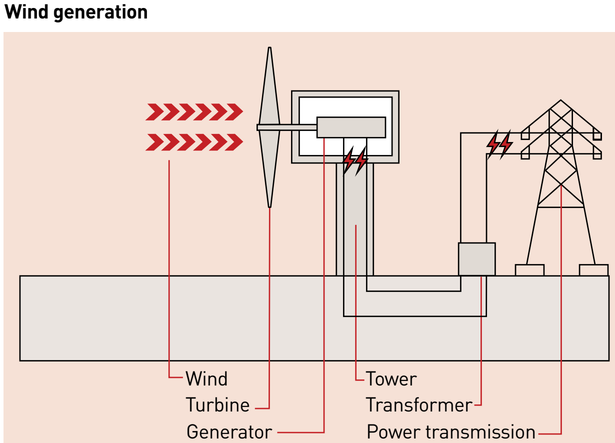
Combined cycle gas fired generation



Hydroelectric generation



Wind generation



Sources: AER (wind); Babcock & Brown (all others).

1.1.1 Lifecycle costs

Figure 1.2 provides estimates of the economic lifecycle costs of different electricity generation technologies in Australia. To allow comparison, the costs of each generation option have been converted to a levelised cost per unit of electricity.[1]

Figure 1.2 includes technologies in use, as well as alternatives such as nuclear energy, and fossil fuel fired generators using carbon capture and storage (CCS) technology.[2] The cost estimates for CCS, which can be used to reduce greenhouse gas emissions from fossil fuel fired generation (coal, gas and oil) technologies, are indicative only.

Developing a consistent evaluation of electricity generation costs across different technologies is difficult, given variations in the size and timing of construction costs, fuel costs, operating and maintenance costs, plant utilisation rates and environmental regulations. Site-specific factors can also affect electricity generation costs. Figure 1.2 thus expresses the economic costs for each technology in wide bands.

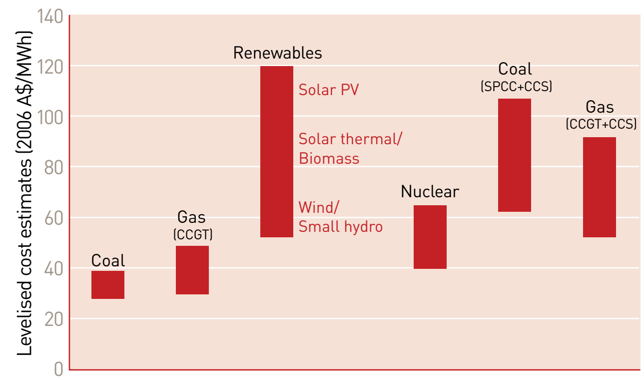
Coal and gas are the lowest cost fuel sources for electricity generation in Australia. Of the renewable technologies currently used here, wind and hydroelectric generation are cheaper over their lifecycle than biomass and solar. The cost of nuclear generation would fall between that for conventional and renewable generation.

1.1.2 Greenhouse gas emissions

Figure 1.3 shows greenhouse gas emissions for a range of different electricity generation technologies, based on current best practice under Australian conditions. The data account for full lifecycle emission contributions —including those from construction and the extraction of fuels—and estimate the emissions per megawatt hour (MWh) of electricity generated.

Figure 1.2

Lifecycle economic costs of electricity generation



CCGT, combined cycle gas turbine; CCS, carbon capture and storage (costs are indicative only); PV, photovoltaic; SPCC, supercritical pulverised coal combustion (in which steam is created at very high temperatures and pressures).

Source: Commonwealth of Australia, *Uranium mining, processing and nuclear energy—opportunities for Australia?*, Report to the Prime Minister by the Uranium Mining, Processing and Nuclear Energy Review Taskforce, Canberra, December 2006.

Renewable sources of electricity (hydroelectric, wind and solar) and nuclear electricity generation have the lowest greenhouse gas emissions of the generation technologies analysed. Of the fossil fuel technologies, natural gas has the lowest emissions and brown coal has the highest. Figure 1.3 does not account for CCS technologies, which could reduce emissions from gas and coal fired generators.

1.2 Generation in the National Electricity Market

About 200 large[3] electricity generators (figure 1.4) operate in the National Electricity Market (NEM) jurisdictions.[4] The electricity produced by major generators in the NEM is sold through a central dispatch process managed by the Australian Energy Market Operator (AEMO). Chapter 2 outlines this process.

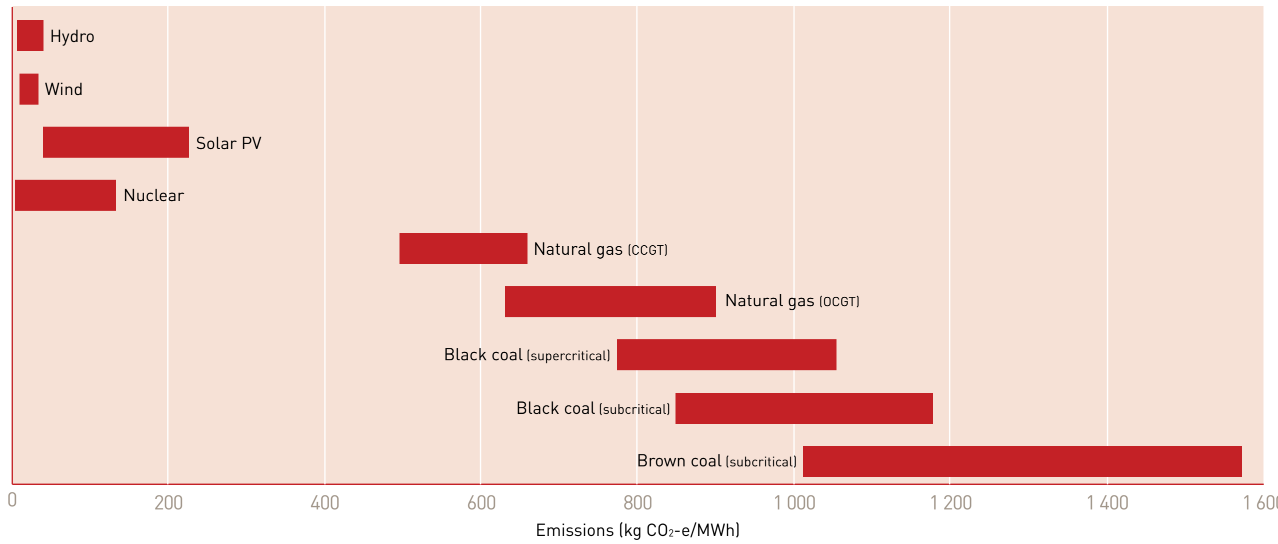
1 The levelised cost of electricity is the real wholesale price of electricity that recoups capital, operating and fuel costs. The present value of expenditures is divided by the electricity generated over the lifetime of the plant to estimate a cost per unit of electricity (in dollars per megawatt hour).

2 Carbon capture and storage, also known as carbon sequestration, is an approach to mitigating carbon dioxide emissions by storing the carbon dioxide. Potential storage methods include injection into underground geological formations, injection deep into the ocean, and industrial fixation in inorganic carbonates. Some industrial processes may use and store small amounts of captured carbon dioxide in manufactured products.

3 'Large' refers to generators with capacity greater than 30 megawatts.

4 This chapter does not cover Western Australia or the Northern Territory, which do not participate in the NEM. Chapter 4 provides information on the generation sectors in those jurisdictions.

Figure 1.3
Lifecycle greenhouse gas emissions from electricity generation



CCGT, combined cycle gas turbine; OCGT, open cycle gas turbine; PV, photovoltaic.

Notes:

The figure shows the estimated range of emissions for each technology and highlights the most likely emissions value. It includes emissions from power station construction and the extraction of fuel sources.

kg CO_2-e/MWh refers to the quantity of greenhouse gas emissions (in kilograms, converted to a carbon dioxide equivalent) that are produced for every megawatt hour of electricity produced.

Source: Commonwealth of Australia, *Uranium mining, processing and nuclear energy—opportunities for Australia?*, Report to the Prime Minister by the Uranium Mining, Processing and Nuclear Energy Review Taskforce, Canberra, December 2006.

The demand for electricity is not constant, varying with time of day, day of week and ambient temperature. Demand tends to peak in summer (when hot weather drives up air conditioning loads) and winter (when cold weather increases heating requirements). A reliable power system needs sufficient capacity to meet these demand peaks. In effect, a substantial amount of capacity may be called on for only brief periods and may remain idle for most of the year.

It is necessary to have a mix of generation capacity that reflects these demand patterns. The mix consists of baseload, intermediate and peaking power stations.

Baseload generators, which meet the bulk of demand, tend to have relatively low operating costs but high start-up costs, making it economical to run them continuously. Peaking generators have higher operating costs and lower start-up costs and are used to supplement baseload at times when prices are high. This normally occurs in periods of peak demand or when an issue such as a network outage constrains the supply of cheaper generators. While peaking generators are expensive to run, they must be capable of a reasonably quick start-up because they may be called on to operate at short notice. There are also intermediate generators, which operate more frequently than peaking plants, but not continuously.

The NEM generation sector uses a variety of fuel sources to produce electricity (figures 1.5a and 1.5b). Black and brown coal account for around 60 per cent of registered[5] generation capacity across the NEM but—as predominantly baseload generators—supply a much larger share of output (85 per cent). Gas fired generation accounts for around 20 per cent of registered capacity but—as intermediate and peaking plant—supplies only around 8 per cent of output.

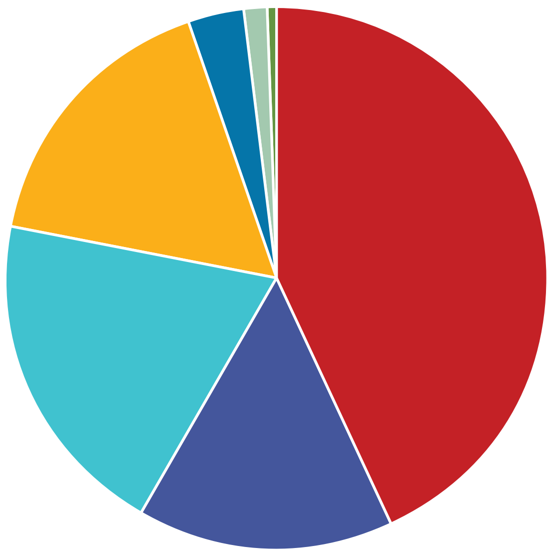
5 Generators seeking to connect to the network must register with the Australian Energy Market Operator, unless granted an exemption.

Figure 1.4
Large electricity generators in the National Electricity Market

Note: Locations are indicative only.

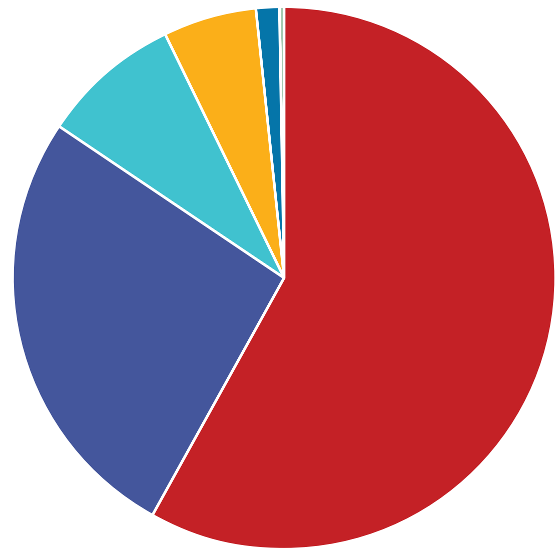
Sources: AEMO/AER.

Figure 1.5a
Registered generation capacity, by fuel source—National Electricity Market, 2009



Black coal **43.3%** Brown coal **15.2%** Gas **19.8%** Hydro **16.5%** Wind **3.5%** Liquid **1.2%** Other **0.5%**

Figure 1.5b
Registered generation output, by fuel source—National Electricity Market, 2009



Black coal **58.2%** Brown coal **26.4%** Gas **8.4%** Hydro **5.5%** Wind **1.3%** Liquid **0.1%** Other **0.1%**

Note: Data based on market output published by AEMO. The data exclude output from non-registered generators.

Sources: AEMO/AER.

Hydroelectric generation accounts for around 17 per cent of registered capacity, but less than 6 per cent of output. Hydro's contribution to output has fallen in the past few years as a result of drought conditions in eastern Australia. Wind plays a relatively minor role in the market (around 4 per cent of capacity and 1 per cent of output), but its role is expected to expand under climate change policies. Liquid fuels account for around 1 per cent of capacity.[6]

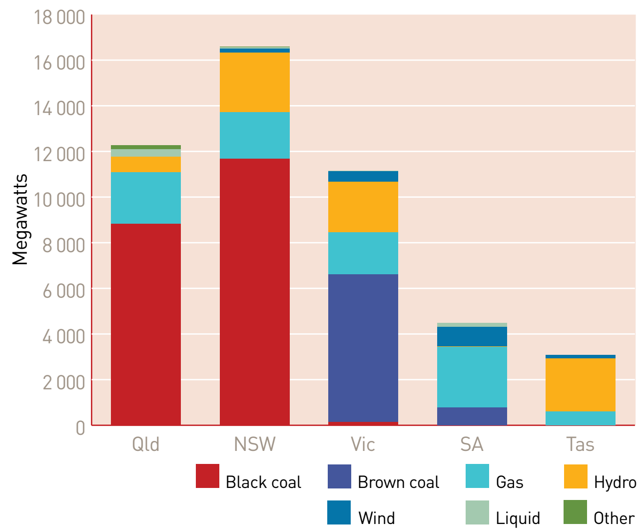
Figure 1.6 sets out regional data on generation capacity by fuel source. Victoria's generation is fuelled by mainly brown coal, supplemented by hydroelectric and gas fired peaking generation. New South Wales and Queensland rely on mainly black coal, but there has been some recent investment in gas fired generation. New South Wales also has some hydroelectric generation, mainly owned by Snowy Hydro.[7] Electricity generation in South Australia is fuelled by mainly natural gas. Tasmania relies on hydroelectric generation primarily, but there has been some recent investment in gas fired generation.

The extent of new and proposed investment in intermittent generation (mainly wind) has raised concerns about system security and reliability. Wind generation grew strongly in the NEM—especially in South Australia—following the introduction of a national mandatory renewable energy target in 2000. That growth led to changes in the way wind generation is integrated into the market.

Since 31 March 2009 new wind generators greater than 30 megawatts (MW) must be classified as 'semi-scheduled' and participate in the central dispatch process. This allows AEMO to limit the output of these generators if necessary to maintain the integrity of the power system. While wind accounts for only around 4 per cent of registered capacity in the NEM, it has a significantly higher share in South Australia at 20 per cent (figure 1.7).

6 Liquid fuels include diesel, distillates and jet fuel.
7 The former Snowy region was abolished on 1 July 2008. It is now split between the Victoria and New South Wales regions of the NEM.

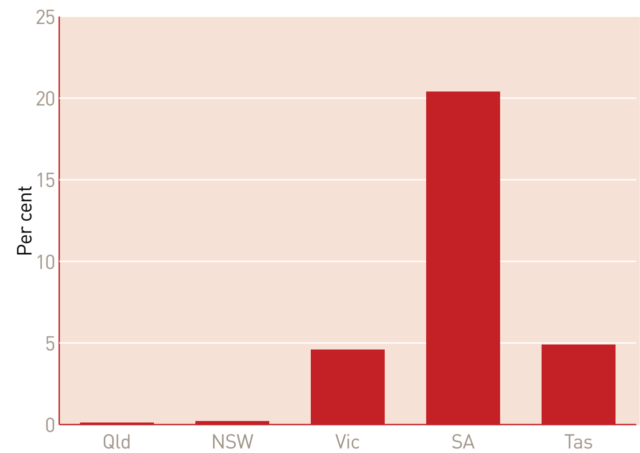
Figure 1.6
Registered generation capacity, by fuel source—regional, 2009



Note: New South Wales and Victoria include Snowy Hydro capacity allocated to those regions.

Sources: AEMO/AER.

Figure 1.7
Wind generation as a percentage of registered capacity, 2009



Sources: AEMO/AER.

The pattern of generation technologies across the NEM is evolving. As indicated in figure 1.3, coal fired generators produce relatively more greenhouse gas emissions than produced by most other technologies. The Australian and state and territory governments have implemented (and are developing) initiatives to encourage the development and use of low emission technologies.

The Australian Government's two primary emissions reduction policies are an emissions trading scheme—called the Carbon Pollution Reduction Scheme (CPRS)—and an expanded national renewable energy target (RET).

On 20 August 2009 the Commonwealth Parliament passed legislation to implement the expanded RET scheme. The scheme is designed to achieve the Australian Government's commitment to a 20 per cent share of renewable energy in Australia's electricity mix by 2020. It increases the national target by more than four times to 45 850 gigawatt hours in 2020, then dropping to 45 000 gigawatt hours for the following decade until 2030. The scheme is set to expire in 2030, by which time the proposed CPRS is intended to result in a sufficiently high carbon price to drive renewable energy projects.

The expanded scheme aims to encourage investment in renewable energy technologies by providing for the creation of renewable energy certificates. One certificate is created for each megawatt hour of eligible renewable electricity generated by an accredited power station, or deemed to have been generated by eligible solar hot water or small generation units. Retailers must obtain and surrender certificates to cover a set proportion of their wholesale electricity purchases. If a retailer fails to surrender enough certificates to cover its liability, then it must pay a penalty for the shortfall.

The design of the proposed CPRS was set out on 15 December 2008 in the *Carbon Pollution Reduction Scheme: Australia's low pollution future* (white paper). On 4 May 2009 the Australian Government announced a delay in the scheme's introduction by one year, to 1 July 2011.

If introduced, the scheme will create a market for the right to emit carbon by placing a cap on Australia's total emissions. In doing so, it is likely to alter the mix of generation output away from fossil fuel fired generation technologies (particularly brown coal), which are relatively low cost but high in emissions, in favour of lower emission and renewable energy technologies.

In addition, governments apply a range of other policies that may affect the generation technology mix. These include low emission generation targets (for example, the Queensland Gas Scheme)[8] and funding for low emission technology development.

1.2.1 Generation ownership

Table 1.1 and figures 1.8 and 1.9 provide information on the ownership of generation businesses in Australia. Across the NEM, around two thirds of generation capacity is government owned or controlled.

In the 1990s Victoria and South Australia disaggregated their generation sectors into multiple stand-alone businesses and privatised each business. Most generation capacity in these jurisdictions is now owned by International Power, AGL Energy, TRUenergy, Great Energy Alliance Corporation (GEAC, in which AGL Energy holds a 32.5 per cent stake) and Snowy Hydro.[9] Some of these businesses have invested in new generation capacity—mainly gas fired intermediate and peaking plants—since the NEM began.

There has been a significant trend in Victoria and South Australia towards vertical integration of electricity generators with retailers. In Victoria, AGL Energy and TRUenergy are key players in both generation and retail. In South Australia, AGL Energy has the largest generation capacity and the largest retail market share. Across Victoria and South Australia, AGL Energy and TRUenergy own or control around 35 per cent of registered generation capacity.[10]

Generation capacity in New South Wales is mainly split between the state owned Macquarie Generation, Delta Electricity and Eraring Energy. Snowy Hydro also has significant hydroelectric generation capacity in that state. There has recently been some private sector investment in New South Wales. TRUenergy and Origin Energy have entered the generation market with the Tallawarra (417 MW) and Uranquinty (678 MW) power stations. They bring the number of private sector generation businesses in New South Wales to five. (Babcock & Brown Power, Marubeni Corporation and Infigen also have small generation holdings.) In total, the private sector accounts for around 10 per cent of the state's generation capacity.

In March 2009 the New South Wales Government announced it would contract the right to sell electricity produced by state owned generators to the private sector. The government expects to complete the sale process in the first half of 2010. It will offer the contracts in the following five bundles:

- Liddell power station (2000 MW, owned by Macquarie Generation)
- Bayswater power station (2640 MW, owned by Macquarie Generation)
- Mount Piper and Wallerawang power stations (2400 MW, owned by Delta Electricity)
- Vales Point, Munmorah and Colongra power stations (2588 MW, owned by Delta Electricity)
- Eraring power station and Shoalhaven pumped storage hydro-electric system (3120 MW, owned by Eraring Energy).[11]

Queensland has disaggregated its generation sector, but government owned businesses (including Tarong Energy, Stanwell Corporation and CS Energy) control around 75 per cent of the state's generation capacity. This includes some joint ventures with the private sector (such as the Tarong North and Callide C power stations) and power purchase agreements over much of the privately owned capacity (such as the Gladstone and Collinsville power stations).

8 Under the scheme, Queensland electricity retailers must source a prescribed percentage (currently 13 per cent) of their electricity from gas fired generation. The target will increase to 15 per cent in 2010, with an option to increase to 18 per cent by 2020. The scheme will be transitioned into the CPRS as soon as is practicable.

9 The New South Wales, Victorian and Australian governments jointly own Snowy Hydro.

10 Includes AGL Energy's 32.5 per cent stake in Loy Yang A and TRUenergy's contractual arrangement for Ecogen Energy's capacity (table 1.1).

11 New South Wales Government, *New South Wales Energy Reform Strategy, delivering the strategy: approach to transactions and market structure*, Sydney, September 2009.

Table 1.1 Generation ownership in the National Electricity Market, July 2009

GENERATING BUSINESS	POWER STATIONS	CAPACITY (MW)	OWNER
NEM REGIONS			
QUEENSLAND			
CS Energy	Callide; Kogan Creek; Swanbank	2254	CS Energy (Qld Government)
Tarong Energy	Tarong; Wivenhoe	1900	Tarong Energy (Qld Government)
Stanwell Corporation	Gladstone	1680	Rio Tinto 42.1%; Transfield Services 37.5%; others 20.4%. All contracted to Stanwell Corporation (Qld Government)
Stanwell Corporation	Barron Gorge; Kareeya; Mackay Gas Turbine; others	1571	Stanwell Corporation (Qld Government)
Callide Power Trading	Callide C	900	CS Energy (Qld Government) 50%; InterGen 50%
Millmerran Energy Trader	Millmerran	852	InterGen 50%; China Huaneng Group 50%
ERM Power and Arrow Energy	Braemar 2	462	ERM Power 50%; Arrow Energy 50%
Braemar Power Project	Braemar 1	450	Babcock & Brown Power
Tarong Energy	Tarong North	443	Tarong Energy (Qld Government) 50%; TEPCO 25%; Mitsui 25%
Origin Energy	Mount Stuart; Roma	314	Origin Energy
AGL Hydro	Oakey	275	Babcock & Brown Power 50%; ERM Group 25%; Contact Energy 25%. All contracted to AGL Energy
AGL Hydro	Yabulu	232	Transfield Services Infrastructure Fund. All contracted to AGL Energy and Arrow Energy
CS Energy	Collinsville	187	Transfield Services Infrastructure Fund. All contracted to CS Energy (Qld Government)
Pioneer Sugar Mills	Pioneer Sugar Mill	68	CSR
Ergon Energy	Barcaldine	49	Ergon Energy (Qld Government)
EDL Projects Australia	Moranbah North	46	EDL Projects Australia
CSR	Invicta Sugar Mill	39	CSR
AGL Energy	German Creek; KRC Cogeneration	32	AGL Energy
Other registered capacity		273	
NEW SOUTH WALES			
Macquarie Generation	Bayswater; Liddell; Hunter Valley	4844	Macquarie Generation (NSW Government)
Delta Electricity	Mount Piper; Vales Point B; Wallerawang; Munmorah; Colongra; others	4547	Delta Electricity (NSW Government)
Eraring Energy	Eraring; Shoalhaven; Brown Mountain; Burrinjuck; others	2972	Eraring Energy (NSW Government)
Snowy Hydro	Blowering; Upper Tumut; Tumut; Guthega	2336	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
Origin Energy	Uranquinty; Cullerin Range	678	Origin Energy
TRUenergy	Tallawarra	417	TRUenergy (CLP Group)
Marubeni Australia Power Services	Smithfield Energy Facility	160	Marubeni Corporation
Redbank Project	Redbank	145	Babcock & Brown Power
Infigen	Capital	140	Infigen Energy
Country Energy	Broken Hill Gas Turbine	50	Country Energy (NSW Government)
Other registered capacity		109	

GEAC, Great Energy Alliance Corporation; NEM, National Electricity Market.

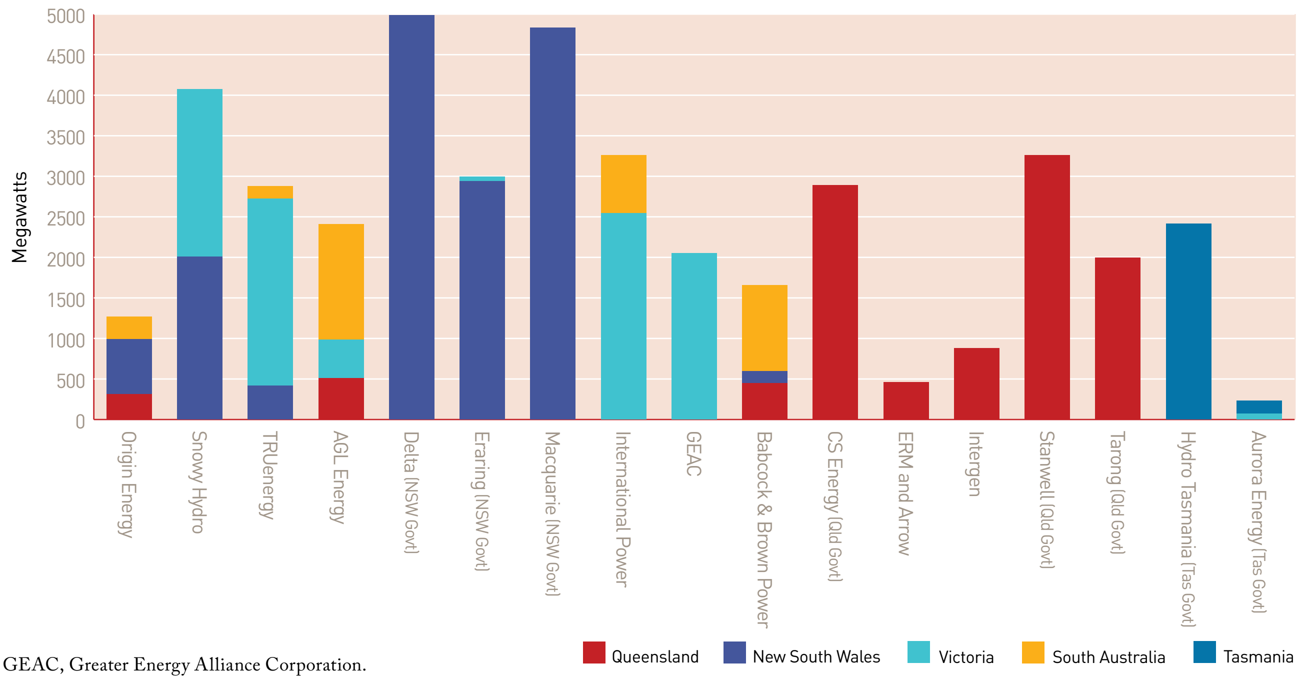
Fuel types: coal; gas; hydro; wind; liquid; biomass/bagasse; unspecified.

Note: Capacity is as published by AEMO for summer 2009–10.

Source: AEMO.

GENERATING BUSINESS	POWER STATIONS	CAPACITY (MW)	OWNER
VICTORIA			
LYMMCo	Loy Yang A	2080	GEAC (AGL Energy 32.5%; TEPCO 32.5%; Transfield Services 14%; others 21%)
Snowy Hydro	Murray; Laverton North; Valley Power	1933	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
Hazelwood Power	Hazelwood	1580	International Power 91.8%; Commonwealth Bank 8.2%
TRUenergy Yallourn	Yallourn; Longford Plant	1451	TRUenergy (CLP Group)
International Power	Loy Yang B	975	International Power 70%; Mitsui 30%
Ecogen Energy	Jeeralang A and B; Newport	891	Industry Funds Management (Nominees) Ltd. All contracted to TRUenergy (CLP Group)
AGL Hydro	Mckay; Somerton; Eildon; Clover; Dartmouth; others	423	AGL Energy
Pacific Hydro	Yambuk; Challicum Hills; Portland	247	Pacific Hydro
Acciona Energy	Waubra	192	Acciona Energy
Energy Brix Australia	Energy Brix Complex; Hrl Tramway Road	160	HRL Group
Alcoa	Angelsea	152	Alcoa
Aurora Energy Tamar Valley	Bairnsdale	70	Babcock & Brown Power
Eraring Energy	Hume	58	Eraring Energy (NSW Government)
Other registered capacity		82	
SOUTH AUSTRALIA			
AGL Hydro	Hallett 1 and 2; Wattle Point	257	AGL Energy
AGL Energy	Torrens Island	1256	AGL Energy
Cathedral Rocks Wind Farm	Cathedral Rocks	66	Roaring 40s (Hydro Tasmania (Tas Government) 50%; CLP Group 50%) 50%; Acciona Energy 50%
Infigen	Lake Bonney 1	81	Infigen Energy. All contracted to Country Energy (NSW Government)
Infigen	Lake Bonney 2	159	Infigen Energy
Flinders Power	Northern; Playford	782	Babcock & Brown Power
Flinders Power	Osborne	175	ATCO 50%; Origin Energy 50%
Infratil Energy Australia	Angaston	49	Infratil. All contracted to AGL Energy
International Power	Pelican Point; Canunda	494	International Power
Transfield Services Infrastructure Fund	Mount Millar	70	Transfield Services Infrastructure Fund
Origin Energy	Quarantine; Ladbroke Grove	267	Origin Energy
Pacific Hydro	Clements Gap	57	Pacific Hydro
Infratil Energy Australia	Snowtown	99	Infratil
Transfield Services Infrastructure Fund	Starfish Hill	35	Transfield Services Infrastructure Fund. All contracted to Hydro Tasmania (Tas Government)
Synergen Power	Dry Creek; Mintaro; Port Lincoln; Snuggery	275	International Power
TRUenergy	Hallet	150	TRUenergy (CLP Group)
Other registered capacity		25	
TASMANIA			
Aurora Energy	Tamar Valley; Bell Bay	374	AETV (Tas Government)
Hydro Tasmania	Gordon; Poatina; Reece; John Butters; Tungatinah; others	2347	Hydro Tasmania (Tas Government)
Hydro Tasmania	Woolnorth	140	Roaring 40s (Hydro Tasmania (Tas Govt) 50%; CLP Group 50%)
Other registered capacity		100	

Figure 1.8
Major stakeholders in National Electricity Market power stations, 2009



GEAC, Greater Energy Alliance Corporation.

Notes:

AGL Energy ownership excludes its 32.5 per cent stake in GEAC, which owns Loy Yang A.

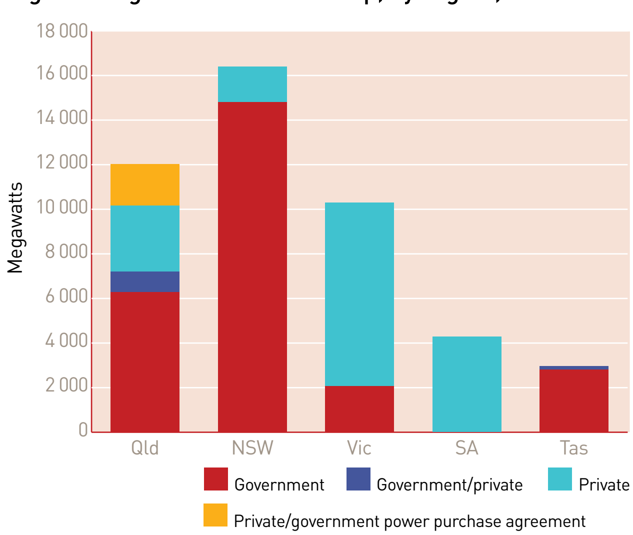
Capacity that is subject to power purchase agreements is attributed to the party with control over output.

Excludes power stations that are not managed through central dispatch.

Some corporate names have been shortened or abbreviated.

Sources: AEMO/AER.

Figure 1.9
Registered generation ownership, by region, 2009



Notes:

'Private/government power purchase agreement' refers to capacity that is privately owned but contracted under power purchase agreements to government owned corporations.

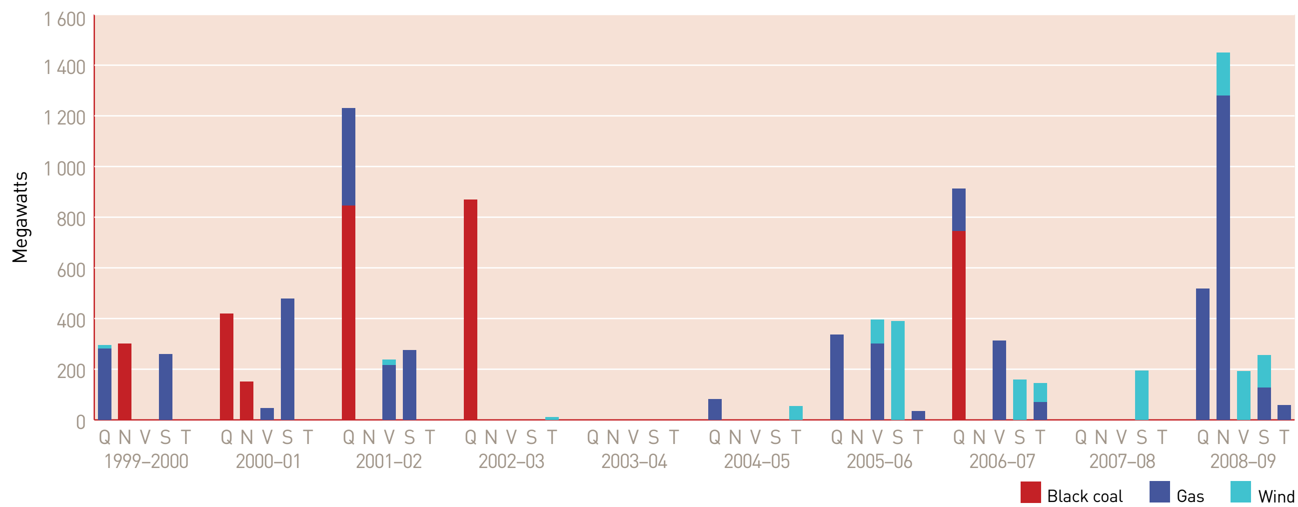
'Government/private' refers to joint venture arrangements between the private and government sectors.

New South Wales and Victoria include Snowy Hydro capacity allocated to those regions.

Sources: AEMO/AER.

Figure 1.10

Annual investment in registered generation capacity



Q, Queensland; N, New South Wales; V, Victoria; S, South Australia; T, Tasmania.

Note: These are gross investment estimates that do not account for decommissioned plant.

Sources: AEMO/AER.

There has been considerable private investment in new capacity in Queensland, including by Rio Tinto, Intergen, Transfield Services Infrastructure Trust, Origin Energy and Babcock & Brown Power. Most recently, ERM Power and Arrow Energy developed the Braemar 2 power station (462 MW), which began operating in 2009.

State owned enterprises own nearly all of the generation capacity in Tasmania. Hydro Tasmania owns the majority, at 2417 MW. Aurora Energy's Tamar Valley peaking plant (166 MW) has recently been expanded with the addition of a 196 MW combined cycle gas turbine.

1.3 Investment

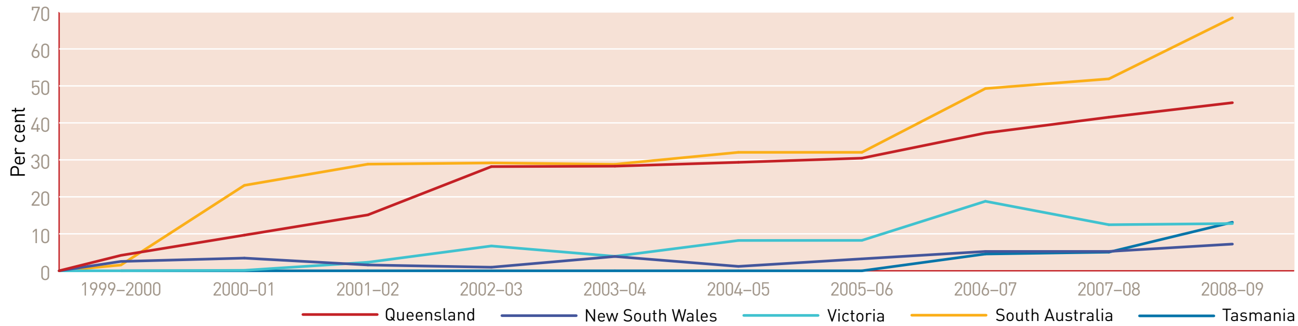
Investment in generation capacity is needed to meet the growing demand for electricity and to maintain the reliability of the power system. It includes the construction of new power stations and upgrades or extensions of existing power stations.

The NEM is an 'energy only' market in which investment is largely driven by price signals in the wholesale and forward markets for electricity (see section 1.4). By contrast, most electricity markets across the world (including Western Australia) use a capacity mechanism to encourage new investment in generation capacity. This may involve a tendering process whereby capacity targets are determined by market operators and then built by the successful tenderers. Chapter 4 describes the Western Australian capacity market.

From the inception of the NEM in 1999 to July 2009, new investment added almost 10 300 MW of registered generation capacity, with around 2500 MW occurring in 2008–09.[12] Figures 1.10 and 1.11 illustrate generation investment since market start. There was strong investment in Queensland and South Australia in the early years of the current decade in response to high wholesale electricity prices. Queensland investment was mainly in baseload generation, whereas South Australian investment was mostly in intermediate and peaking generation. There was also some peaking investment in Victoria.

12 There has also been investment in other generators—for example, small generators, remote generators not connected to a transmission network and generators that produce exclusively for self-use (such as for remote mining operations).

Figure 1.11
Change in net generation capacity since market start



Note: Net change in registered capacity from 1998–99. A decrease may reflect a reduction of capacity due to decommissioning or a reduction in capability of existing generation units.

Sources: AEMO/AER.

There was negligible investment across the NEM in the middle of the current decade. But then tightening supply conditions led to significant new investment in the latter part of the decade. There has been continuing new investment in Queensland and in gas fired plant in New South Wales in 2008–09. South Australia has recorded strong growth in wind capacity over the past few years.

1.3.1 Recent investment

Investment in generation capacity needs to respond to projected market requirements for electricity. Table 1.2a sets out major new generation investment that came on line in the NEM in 2008–09, excluding wind. The bulk of new investment (1240 MW) has occurred in New South Wales, of which around 1100 MW was privately developed by Origin Energy and TRUenergy. Queensland has added around 460 MW of private investment, developed by ERM Power and Arrow Energy. There was new investment by government businesses in New South Wales and Tasmania. All new investment in 2008–09 was in gas fired generation.

Table 1.2b shows almost 500 MW of new wind generation investment in the NEM in 2008–09. The investment occurred in Victoria, New South Wales and South Australia.

Table 1.2c sets out committed investment projects in the NEM at June 2009. It includes those already under construction and those where developers and financiers have formally committed to construction. AEMO accounts for committed projects in projecting electricity supply and demand. There is around 2650 MW of committed capacity in the NEM, of which more than 2200 MW is gas fired generation. Most projects are expected to be commissioned by the end of 2010. There were no major committed projects added in 2008–09.

1.3.2 Proposed projects

Proposed projects include generation capacity that is either in the early stages of development or at more advanced stages but not fully committed. Such projects may be shelved if circumstances change, such as a change in demand projections or business conditions.

The AEMO website lists proposed generation projects in the NEM that are 'advanced' or publicly announced. AEMO considers these projects to be speculative and thus excludes them from its supply and demand outlooks. At June 2009 it listed around 8760 MW of proposed capacity (excluding wind) in the NEM (table 1.3).[13] There is significant proposed investment in gas fired generation, mainly for New South Wales (possibly because the region is the highest net importer in the NEM) and Queensland.

13 Sourced from AEMO's generator information page (www.aemo.com.au/data/gendata.shtml), viewed 14 August 2009.

Table 1.2a Generation investment in the National Electricity Market, 2008–09 (excluding wind)

REGION	POWER STATION	DATE COMMISSIONED	TECHNOLOGY	CAPACITY (MW)	ESTIMATED COST ($ MILLION)	OWNER
Qld	Braemar 2	April–June 2009	OCGT	462	546	ERM Power and Arrow Energy
NSW	Colongra (unit 1)	June 2009	OCGT	157		Delta Electricity
NSW	Tallawarra	February 2009	CCGT	435	350	TRUenergy
NSW	Uranquinty	October 2008 – January 2009	OCGT	648	700	Origin Energy
SA	Quarantine	March 2009	OCGT	128	90	Origin Energy
Tas	Tamar Valley Peaking	April 2009	OCGT	58		Aurora Energy

Table 1.2b Wind generation investment in the National Electricity Market, 2008–09

REGION	POWER STATION	CAPACITY (MW)	ESTIMATED COST ($ MILLION)	OWNER
NSW	Cullerin Range	30	95	Origin Energy
NSW	Capital	140	220	Renewable Power Ventures
Vic	Waubra	192	450	Acciona Energy
SA	Clements Gap	57	135	Pacific Hydro
SA	Hallett 2	71	159	AGL Hydro

Note: Tables 1.2a and 1.2b are based on publicly available information.

Table 1.2c Committed investment projects in the National Electricity Market, June 2009

DEVELOPER	POWER STATION	TECHNOLOGY	CAPACITY (MW)	PLANNED COMMISSIONING DATE
QUEENSLAND				
Queensland Gas Company	Condamine	CCGT	135	2009–10
Origin Energy	Darling Downs	CCGT	605	2010
Origin Energy	Mount Stuart (extension)	OCGT	127	2009
Rio Tinto	Yarwun Cogen	Gas cogeneration	152	2010
NEW SOUTH WALES				
Eraring Energy	Eraring (extension)	Coal fired	120	2010–11
Delta Electricity	Colongra (units 2–4)	OCGT	471	
VICTORIA				
AGL Energy	Bogong	Hydro	140	2009–10
Origin Energy	Mortlake	OCGT	518	2010
Pacific Hydro	Portland	Wind	164	2009–10
SOUTH AUSTRALIA				
International Power	Port Lincoln	OCGT	25	2010
TASMANIA				
Aurora Energy	Tamar Valley	CCGT	196	2009

CCGT, combined cycle gas turbine, OCGT, open cycle gas turbine.

Note: Capacity is summer capacity for all generators.

Source: AEMO.

Table 1.3 **Major proposed generation investment in the National Electricity Market, June 2009**

DEVELOPER	POWER STATION	TECHNOLOGY	CAPACITY (MW)	PLANNED COMMISSIONING DATE
QUEENSLAND				
Origin Energy	Spring Gully	CCGT	1000	n/a
ERM Power	Braemar 3	Gas	462	2012
ERM Power	Braemar 4	Gas	434	2013
CS Energy	Swanbank F	CCGT	380	2012
NEW SOUTH WALES				
ERM Power	Wellington (Units 1–4)	OCGT	616	2011
Delta Electricity	Mount Piper expansion	Coal	600	2015–16
Macquarie Generation	Tomago Gas Turbine	OCGT	500	n/a
Delta Electricity	Bamarang	CCGT	450	2012–13
Delta Electricity	Marulan gas turbine	CCGT	420	2013–14
AGL Energy	Leaf's Gully	Gas	360	2012
Delta Electricity	Bamarang	OCGT	330	2012–2013
Delta Electricity	Marulan gas turbine	OCGT	330	2013–14
ERM Power	Wellington (Unit 5)	OCGT	280	2012
International Power	Parkes	OCGT	150	n/a
International Power	Buronga	OCGT	120	n/a
Eraring Energy	Eraring upgrade	Coal	60	2011
Eraring Energy	Eraring upgrade	Coal	60	2012
VICTORIA				
Santos	Shaw River	CCGT	500	2012
AGL Energy	Tarrone	Gas	500	2012
HRL Group and Harbin Power Engineering	IDGCC demonstration plant	IDGCC	500	2013
Origin Energy	Mortlake (Stage 2)	CCGT	470	n/a
Solar System	Solar System Victorian Solar Energy Facility (Units 2–51)	Solar Concentrator	100	2012
Solar System	Solar Systems Victorian Solar Energy Facility (Units 52–77)	Solar Concentrator	54	2013
SOUTH AUSTRALIA				
Altona Resources	Arkaringa	IGCC	560	2014
International power	Pelican Point (Stage 2)	Gas	300	n/a
Strike Oil	Kingston	Coal	40	2015
TASMANIA				
Gunns	Bell Bay pulp mill power plant	Biomass	184	2012

CCGT, combined cycle gas turbine; IDGCC, integrated drying and gasification combined cycle; IGCC, integrated gasification combined cycle; OCGT, open cycle gas turbine; n/a, not available.

Note: Excludes wind generation.

Source: AEMO

1.3.3 Wind projects

AEMO reports wind generation investment separately from other proposed investment because wind capacity depends on the weather and cannot be relied on to generate at specified times.[14] At June 2009 it listed around 6730 MW of proposed wind capacity, mainly in Victoria, New South Wales and South Australia (table 1.4).

Table 1.4 Major proposed wind generation investment in the National Electricity Market, June 2009

COMMISSIONING DATE	CAPACITY (MW) QLD	NSW	VIC	SA	TAS	TOTAL
2009				39		39
2010		92	198	129	117	536
2011		1516	564	724		2804
2012		350	760			1110
2013			480			480
2014	101		234		300	635
2015	50			71		121
2016	80	149				229
2017			120			120
2018				109		109
2019		53		80		133
Unknown		30	144	242		416
Total	231	2190	2500	1394	417	6732

Source: AEMO.

1.4 Reliability of the generation sector

Reliability refers to the continuity of electricity supply to customers. The Australian Energy Market Commission (AEMC) Reliability Panel sets the reliability standard for the NEM. The standard requires sufficient generation and bulk transmission capacity to ensure, in the long term, no more than 0.002 per cent of customer demand in each NEM region is at risk of not being supplied. To ensure the standard is met, AEMO determines the necessary spare capacity for each region that must be available (either within the region or via transmission interconnectors). These minimum reserves provide a buffer against unexpected demand spikes and generation failure. The panel also recommends a wholesale market price cap, which is set at a level to stimulate sufficient investment in generation capacity to meet the reliability standard. A review in 2007 of the reliability settings led to a decision to increase the market price cap from $10 000 per MWh to $12 500 per MWh, to take effect on 1 July 2010.

The panel reports annually on the performance of the generation sector against the reliability standard and minimum reserve levels set by AEMO. In practice, generation has proved highly reliable. Reserve levels are rarely breached and generator capacity across all regions of the market is generally sufficient to meet peak demand and allow for an acceptable reserve margin.

The performance of generators in maintaining reserve levels has improved since the NEM began in 1998, most notably in South Australia and Victoria. This reflects significant generation investment and improved transmission interconnection capacity across the regions. Table 1.5 sets out the performance of the generation sector in selected regions against the reliability standard. The reliability of all regions falls within the standard.

There have been three instances of insufficient generation capacity to meet consumer demand from the commencement of the NEM to 30 June 2009. The first occurred in Victoria and South Australia in early 2000, when a coincidence of industrial action, high demand and temporary loss of generating units resulted in load shedding. The scope of the reliability standard was amended following the release of the AEMC's *Comprehensive reliability review—final report* in December 2007, to exclude unserved energy associated with power system incidents resulting from industrial action or 'acts of God' at transmission facilities.[15] Accordingly, revised calculations of unserved energy exclude the event in 2000.

14 The Australian Energy Market Commission published a final Rule determination on 1 May 2008 that requires new intermittent generators to register under the new classification of 'semi-scheduled generator'. These generators must participate in the central dispatch process. Additionally, in 2004 the South Australian regulator, the Essential Services Commission of South Australia (ESCOSA), implemented licence conditions preventing wind farms from being classified as non-scheduled. Accordingly, all wind farms commissioned in South Australia since that date are classified as scheduled generation. Some pre-existing South Australian wind farms also have changed classification, from non-scheduled to scheduled.

15 AEMC Reliability Panel, *Reliability standard and settings review, issues paper*, Sydney, June 2009.

Mark Wilson

The second event occurred in New South Wales on 1 December 2004, when a generator failed during a period of record summer demand. The restoration of load began within 10 minutes. The most recent instance of insufficient generation occurred on 29 and 30 January 2009 in Victoria and South Australia. Extremely high temperatures led to record demand in Victoria and near record demand in South Australia. Unplanned outages on Basslink on each day exacerbated the tight supply conditions in Victoria and South Australia. This led to supply interruptions on two days in South Australia (for 90 minutes and 165 minutes respectively) and Victoria (for 160 minutes and 230 minutes respectively).[16]

Table 1.5 Unserved energy—long term averages, December 1998 to June 2009

REGION	UNSERVED ENERGY (%)
Queensland	0.00000
New South Wales	0.00010
Victoria	0.00044
South Australia	0.00051

Note: There has been no breach of the reliability standard in Tasmania since it joined the NEM in 2005.

Source: AEMC Reliability Panel, *Reliability standard and settings review, issues paper*, Sydney, June 2009.

1.4.1 Excluded events

The power system is operated to cope with only credible contingencies. Some power supply interruptions are caused by non-credible (multiple contingency) events. This may involve several credible events occurring simultaneously or in a chain reaction—for example, several generating units might fail or 'trip' at the same time, or a transmission fault might occur at the same time as a generator trips. It would be inefficient to operate the power system to cope with non-credible events. Likewise, additional investment in generation or networks may not necessarily avoid such interruptions. For this reason, these events are excluded from reliability calculations.

1.4.2 Reviews of the reliability settings

The AEMC Reliability Panel is required to review the reliability standard and mechanisms every two years. The next review is to be completed by 30 April 2010, with any changes to apply from 1 July 2012. In addition, the AEMC is reviewing the effectiveness of the NEM security and reliability arrangements in the light of extreme weather events. The review, also to be completed by April 2010, will assess:

> whether the current reliability standard conforms with public expectations of supply reliability
> the impact of a range of market price caps on reliability and costs to customers
> whether the process of determining the reliability standard and market price cap requires change.

Further, in June 2009 the panel began a review of the operational arrangements to meet the reliability standard. The review is considering the process for determining minimum reserve levels and obligations on market participants to provide AEMO with accurate information on generation availability.

The NEM combines a number of mechanisms to ensure high levels of reliability in supply. AEMO publishes forecasts of electricity demand and generator availability to allow generators to respond to market conditions and determine the scheduling of maintenance outages. It can intervene in the market when generation capacity forecasts indicate capacity is unlikely to be sufficient to meet minimum reserve levels. The reliability and emergency reserve trader (RERT) mechanism allows AEMO to enter reserve contracts with generators to ensure sufficient reserves to meet the reliability standard. When entering these contracts, AEMO must give priority to facilities that would least distort wholesale market prices. Reserves were contracted through the reserve trading mechanism for the first time in Victoria and South Australia in February 2005 and again in February 2006, but were ultimately not required on either occasion. AEMO can also intervene in the market through its directions power, requiring

16 There were further network outages in Victoria on the evening of 30 January, leading to localised interruptions to customers. The interruptions were not related to a shortfall in generation supply.

generators to provide additional supply at the time of dispatch to ensure sufficient reserves.

In 2008 the AEMC commenced a review of the energy market frameworks to determine their adequacy to accommodate climate change policies, particularly the CPRS and expanded RET. The final report (published 8 October 2009) raised concerns that the current reliability mechanisms—including the RERT mechanism and directions power—do not adequately address the risk of short term generation capacity shortfalls. Addressing this concern, the AEMC Reliability Panel proposed changing the Electricity Rules to allow more flexibility in contracting under the RERT mechanism, including the establishment of a panel of participants and a short notice contracting process.

The AEMC also supported changing the Electricity Rules to require more accurate reporting of demand-side capability. This proposal aims to minimise AEMO's intervention in the market by improving the quality of reserve assessments.

1.4.3 Investment in generation and long term reliability

While the NEM combines a number of mechanisms to manage short term generation capacity issues, a reliable power supply in the longer term needs sufficient investment in generation to meet the needs of customers.

A central element in the design of the NEM is that spot prices respond to a tightening in the supply–demand balance. Wholesale prices and projections of the supply–demand balance are also factored into forward prices in the contract market (see chapter 3). Regions with potential generation shortages (which could lead to reliability issues), therefore, will exhibit rising prices in the spot and contract markets. High prices may help attract investment to areas where it is needed, and may lead to some demand-side response if suitable metering and price signals are available to customers —for example, retailers may offer financial incentives for customers to reduce consumption at times of high system demand, to ease pressure on prices.

Seasonal factors (for example, summer peaks in air conditioning loads) create a need for peaking generation to cope with periods of extreme demand. The NEM price cap of $10 000 per MWh is necessarily high to encourage investment in peaking plant, which is expensive to run and may operate only rarely. Over the longer term, peaking plant plays a critical role in ensuring there is adequate generation capacity (and thus reliability). There has been significant investment in peaking capacity in most regions of the NEM over the past few years.

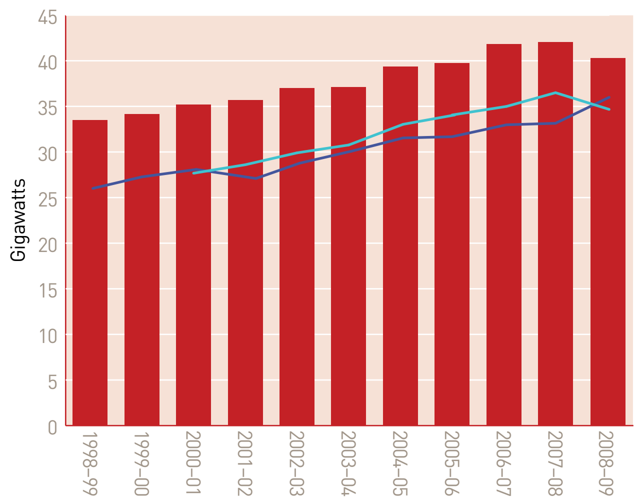
Historical adequacy of generation to meet demand

Figure 1.12 compares total generation capacity with national peak demand since the NEM began. It shows actual demand and AEMO's demand forecasts two years in advance. The data indicate that investment in the NEM over the past decade has kept pace with rising demand (both actual and forecast levels), and has provided a safety margin of capacity to maintain the reliability of the power system. In 2008–09 actual demand was above forecast demand for the first time since 2000–01.

Reliability outlook

The relationship between future demand and available capacity determines electricity prices and the reliability of the power system looking ahead. Figure 1.13 charts forecast peak demand in the NEM against installed, committed and proposed capacity. It indicates the amount of capacity that AEMO considers would be needed to maintain reliability, given projected demand. Wind generation is treated differently from conventional generation for the purpose of the supply–demand balance. In South Australia, for example, a figure of 3 per cent of installed wind capacity is used to represent the contribution to overall generation supply at times of peak demand; 8 per cent is used in Victoria.

Figure 1.12
National Electricity Market peak demand and generation capacity



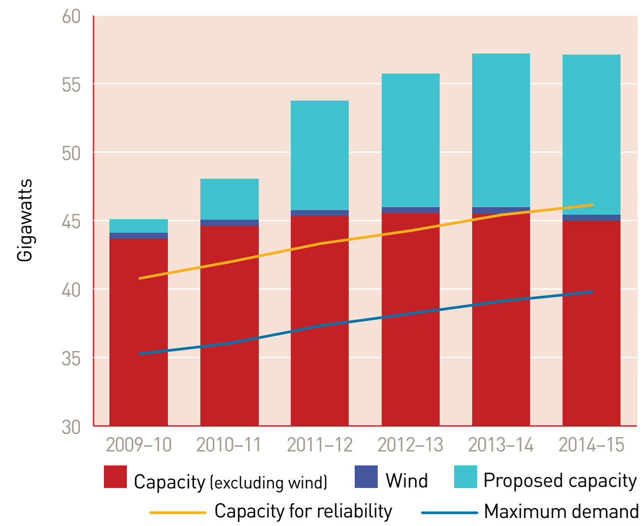
Notes:

Demand forecasts are two years in advance, based on a 50 per cent probability that the forecast will be exceeded and a coincidence factor of 95 per cent.

NEM capacity excludes wind generation and power stations not managed through central dispatch.

Source: AEMO, *Electricity statement of opportunities for the National Electricity Market*, Melbourne, various years.

Figure 1.13
Demand and generation capacity outlook to 2014–15



Notes:

Capacity (excluding wind) is scheduled capacity and encompasses installed and committed capacity. Wind capacity includes scheduled and semi-scheduled wind generation. Proposed capacity includes wind projects (see tables 1.3 and 1.4).

The maximum demand forecasts for each region in the NEM are aggregated based on a 50 per cent probability of exceedance and a 95 per cent coincidence factor. Unscheduled generation is treated as a reduction in demand.

Reserve levels required for reliability are based on an aggregation of minimum reserve levels for each region. Accordingly, the data cannot be taken to indicate the required timing of new generation capacity within individual NEM regions.

Data source: AEMO, *Electricity statement of opportunities for the National Electricity Market*, Melbourne, 2009.

Figure 1.13 indicates that current installed and committed capacity will be sufficient to meet peak demand projections and reliability requirements until at least 2012–13.

While the uncertain nature of proposed projects means they cannot be factored into AEMO's reliability equations, they indicate the market's awareness of future capacity needs. In particular, they indicate the extent of competition in the market to develop electricity infrastructure. Figure 1.13 indicates the possible extent of proposed capacity required to be constructed to meet projected shortfalls beyond 2012–13. While many proposed projects may never be constructed, only a relatively small percentage would need to occur to meet demand and reliability requirements into the next decade.

2 NATIONAL ELECTRICITY MARKET

Generators in the National Electricity Market sell electricity to retailers through wholesale market arrangements whereby the dynamics of supply and demand determine prices and investment. The Australian Energy Regulator monitors the market to ensure participants comply with the National Electricity Law and National Electricity Rules.

2 NATIONAL ELECTRICITY MARKET

This chapter considers:

- features of the National Electricity Market
- how the wholesale market operates
- the demand for electricity by region, and electricity trade across regions
- spot prices for electricity, including international comparisons.

2.1 Features of the National Electricity Market

The National Electricity Market (NEM) is a wholesale market through which generators and retailers trade electricity in eastern and southern Australia. There are six participating jurisdictions—Queensland, New South Wales, the Australian Capital Territory (ACT), Victoria, South Australia and Tasmania—that are physically linked by an interconnected transmission network.

The NEM has around 270 registered generators, six state based transmission networks[1] (linked by cross-border interconnectors) and 13 major distribution networks that collectively supply electricity to end use customers. In geographic span, the NEM is the largest interconnected power system in the world. It covers a distance of 4500 kilometres, from Cairns in northern Queensland to Port Lincoln in South Australia and Hobart in Tasmania. The market has five regions: New South Wales, Queensland, Victoria, South Australia and Tasmania.

1 In New South Wales, there are two transmission networks: TransGrid and EnergyAustralia. EnergyAustralia's transmission network assets support the TransGrid network.

The NEM supplies electricity to almost nine million residential and business customers. In 2008–09 the market generated around 208 terawatt hours (TWh)[2] of electricity, with a turnover of $9.4 billion (table 2.1).

Table 2.1 **National Electricity Market at a glance**

Participating jurisdictions	Qld, NSW, Vic, SA, Tas, ACT
NEM regions	Qld, NSW, Vic, SA, Tas
Registered capacity	47 418 MW
Number of registered generators	268
Number of customers	8.8 million
NEM turnover 2008–09	$9.4 billion
Total energy generated 2008–09	208 TWh
National maximum winter demand 2008–09 (11 June 2009)	32 094 MW[1]
National maximum summer demand 2008–09 (29 January 2009)	35 551 MW

TWh, terrawatt hour; MW, megawatt; NEM, National Electricity Market.
1. The maximum historical winter demand of 34 422 MW occurred in 2008.
Sources: AEMO; ESAA, *Electricity gas Australia*, Melbourne, 2009, p. 26.

2.2 How the National Electricity Market works

The NEM is a wholesale pool into which generators sell their electricity. The main customers are retailers, which buy electricity for resale to business and household customers. While an end use customer can buy directly from the pool, few choose this option.

The market has no physical location, but is a virtual pool in which a central operator aggregates and dispatches supply bids to meet demand. The Australian Energy Market Operator (AEMO) has managed the operation of the NEM since 1 July 2009.[3] The Australian Energy Regulator (AER) monitors the market to ensure participants comply with the National Electricity Law and Rules.

The design of the NEM reflects the physical characteristics of electricity:

> Supply must meet demand at all times because electricity cannot be economically stored. Coordination is thus required to avoid imbalances that could seriously damage the power system.
> One unit of electricity cannot be distinguished from another, making it impossible to determine which generator produced which unit of electricity and which market customer consumed that unit. The use of a common trading pool addresses this issue by removing any need to trace particular generation to particular customers.

The NEM is a gross pool, meaning all sales of electricity must occur through a central trading platform. In contrast, a net pool or voluntary pool would allow generators to contract with market customers directly for the delivery of some electricity. Western Australia's electricity market uses a net pool arrangement (see chapter 4). Both market designs require the market operator to be informed of all sales so the physical delivery of electricity can be centrally managed.

Unlike some overseas markets, the NEM does not provide additional payments to generators for capacity or availability. This characterises the NEM as an 'energy only' market and explains the high price cap of $10 000 per megawatt hour (MWh).[4] Generators earn their income in the NEM from market transactions, either in the spot or ancillary services[5] markets or by trading hedge instruments in financial markets[6] outside NEM arrangements.

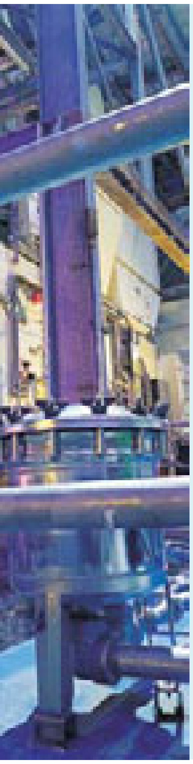
2 One TWh is equivalent to 1000 gigawatt hours (GWh), 1 000 000 megawatt hours (MWh) and 1 000 000 000 kilowatt hours (KWh). One TWh is enough energy to light 10 billion light bulbs with a rating of 100 watts for one hour.

3 The National Electricity Market Management Company managed the market until 1 July 2009.

4 The market price cap will increase from $10 000 per MWh to $12 500 per MWh on 1 July 2010.

5 AEMO operates a market for frequency control ancillary services that relate to electricity supply adjustments to maintain the power system frequency within the standard. Generators can bid offers to supply these services into spot markets that operate in a similar way to the wholesale energy market.

6 See chapter 3.



Box 2.1 Development of the National Electricity Market

Historically, governments owned and operated the electricity supply chain from generation through to retailing. There was no wholesale market because generation and retail were operated by vertically integrated state based utilities. Typically, each jurisdiction generated its own electricity needs, with limited interstate trade.

Australian governments began to reform the electricity industry in the 1990s. The vertically integrated utilities were separated into generation, transmission, distribution and retail businesses. For the first time, generation and retail activities were exposed to competition. This created an opportunity to develop a wholesale market that extended beyond jurisdictional borders.

In 1996 Queensland, New South Wales, the ACT, Victoria and South Australia agreed to pass the National Electricity Law, which provided the legal basis to create the NEM. The market commenced in December 1998.

While Queensland was part of the NEM from inception, it was not physically interconnected with the market until 2000–01 when two transmission lines (Directlink and the Queensland to New South Wales interconnector) linked the Queensland and New South Wales networks. Tasmania joined the NEM in 2005 and was physically interconnected with the market in April 2006 with the opening of Basslink, a submarine transmission cable from Tasmania to Victoria.

The Snowy region was abolished on 1 July 2008 through a regional boundary change. The area formerly covered by the region is now split between the Victoria and New South Wales regions of the NEM. The other regions—Queensland, South Australia and Tasmania—follow jurisdictional boundaries.

2.2.1 Market operation

As market operator, AEMO coordinates a central dispatch process to manage the wholesale spot market. The process matches generator supply offers to demand in real time: AEMO issues instructions to each generator to produce the required quantity of electricity that will meet demand at all times at the lowest available cost, while maintaining the technical security of the power system.

Some generators bypass the central dispatch process, including some wind generators,[7] those not connected to a transmission network (for example, embedded generators) and those producing exclusively for their own use (such as in remote mining operations).

2.2.2 Demand and supply forecasting

AEMO monitors demand and capacity across the NEM and issues demand and supply forecasts to help participants respond to the market's requirements. While demand varies, industrial, commercial and household customers each have relatively predictable patterns, including seasonal demand peaks related to extreme temperatures. Using data such as historical load (demand) patterns and weather forecasts, AEMO develops demand projections. Similarly, it estimates the adequacy of supply in its projected assessment of system adequacy (PASA) reports. It publishes a seven day PASA report that is updated every two hours, and a two year PASA report that is updated weekly. In response to the growth in wind generation and its impact on the forecasting process, AEMO recently introduced a wind forecasting system in the NEM. It aims to provide better forecasts that will improve dispatch efficiency, pricing, and network and security management.

7 From 31 March 2009 new wind and other intermittent generators must register under the new classification of 'semi-scheduled generator'. The generators must participate in the central dispatch process, including by submitting offers and by limiting their output if requested by AEMO.

2.2.3 Central dispatch and spot prices

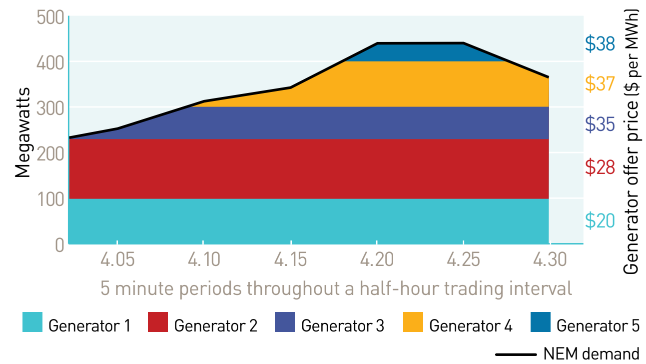
Market supply is based on the offers of generators to produce particular quantities of electricity at various prices for each of the 5 minute dispatch periods in a day. Generators must lodge offers ahead of each trading day. They can change their offers (rebid) at any time subject to those bids being in 'good faith'.

Generator offers are affected by a range of factors, including plant technology. Coal fired generators, for example, need to ensure their plants run constantly to cover their high start-up costs, and they may offer to generate some electricity at low or negative prices to guarantee dispatch.[8] Gas fired peaking generators face high operating costs and normally offer to supply electricity only when prices are high.

To determine which generators are dispatched, AEMO stacks the offer bids of all generators in ascending price order for each 5 minute dispatch period. It dispatches the cheapest generator bids first, then progressively more expensive offers until enough electricity is dispatched to satisfy demand. This results in demand being met at the lowest possible cost. In practice, the dispatch order may be modified by a number of factors, including generator ramp rates—that is, how quickly generators can adjust their level of output—and congestion in transmission networks.

The dispatch price for a 5 minute interval is the offer price of the highest (marginal) priced megawatt (MW) of generation that must be dispatched to meet demand. In figure 2.1, the demand for electricity at 4.15 is about 350 MW. To meet this level of demand, generators 1, 2 and 3 are fully dispatched and generator 4 is partly dispatched. The dispatch price (or marginal price), therefore, is $37 per MWh. By 4.20, demand has risen to the point where a fifth generator needs to be dispatched. This higher cost generator has an offer price of $38 per MWh, which drives up the price to that level.

Figure 2.1
Illustrative generator offers (megawatts) at various prices



Source: AEMO.

A wholesale spot price is determined for each half-hour period (trading interval) and is the average of the 5 minute dispatch prices during that interval. In figure 2.1, the spot price in the 4.00–4.30 interval is about $37 per MWh. This is the price that all generators receive for their supply during this 30 minute period, and the price that market customers pay for the electricity they use in that period. A separate spot price is determined for each region, accounting for the physical losses in the transport of electricity over distances and transmission congestion that can sometimes isolate particular regions from the national market (see section 2.4).

The price mechanism in the NEM allows spot prices to respond to a tightening in the supply–demand balance. This creates signals for demand-side responses. If, for example, suitable metering arrangements are available, then some customers may be able to reduce their consumption during peak demand periods when prices are high (see section 2.6). In the longer term, price movements also create signals for new investment (see sections 1.3 and 2.6).

8 The minimum allowed bid price is –$1000 per MWh.

2.3 Demand and capacity

Annual electricity consumption in the NEM rose from under 170 TWh in 1999–2000 to 208 TWh in 2008–09 (figure 2.2a). The entry of Tasmania in 2005 accounted for around 10 TWh. Demand levels fluctuate throughout the year, with peaks occurring in summer (for air conditioning) and winter (for heating). The peaks are closely related to temperature. Figure 2.2b shows seasonal peaks have risen nationally, from around 26 gigawatts (GW) in 1999 to over 35 GW in 2009. The volatility in the summer peaks reflects variations in weather conditions from year to year.

Figure 2.2a
National Electricity Market electricity consumption

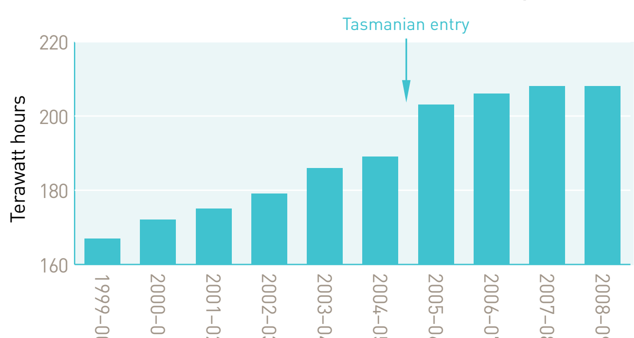
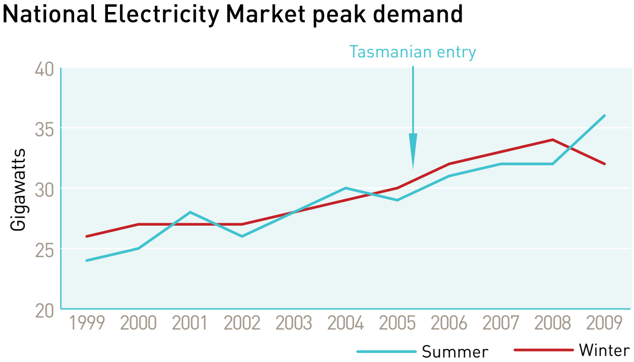


Figure 2.2b
National Electricity Market peak demand



Sources: AEMO; AER.

Table 2.2 sets out annual electricity consumption across the NEM since 1999–2000. Reflecting its population base, New South Wales has the highest consumption of electricity, followed by Queensland and Victoria. Demand is considerably lower in the less populated regions of South Australia and Tasmania.

Figure 2.3 compares seasonal peak demand across the regions. Victoria, South Australia and Queensland experience high demand in summer due to air conditioning loads. Tasmania tends to experience its maximum demand in winter due to heating loads. New South Wales has alternated between summer and winter peaking for several years.

2.4 Trade across the regions

The NEM promotes efficient generator use by allowing trade in electricity among the five regions, which are linked by transmission interconnectors. Trade enhances the reliability of the power system by allowing the regions to draw on a wider pool of reserves to manage system constraints and outages.

Trade also provides economic benefits by allowing high cost generating regions to import electricity from lower cost regions. On a day of peak electricity demand in South Australia, for example, low cost baseload power from Victoria may provide a competitive alternative to South Australia's high cost peaking generators. The NEM means AEMO can dispatch electricity from lower cost regions and export it to South Australia until the technical capacity of the interconnectors is reached.

Figure 2.4 shows annual electricity consumption and trade across the regions in 2008–09. It also shows each region's generation capacity factor (the use of local generation capacity). The NEM's interregional trade relationships are also reflected in figure 2.5, which shows the net trading position of the regions since the NEM commenced.

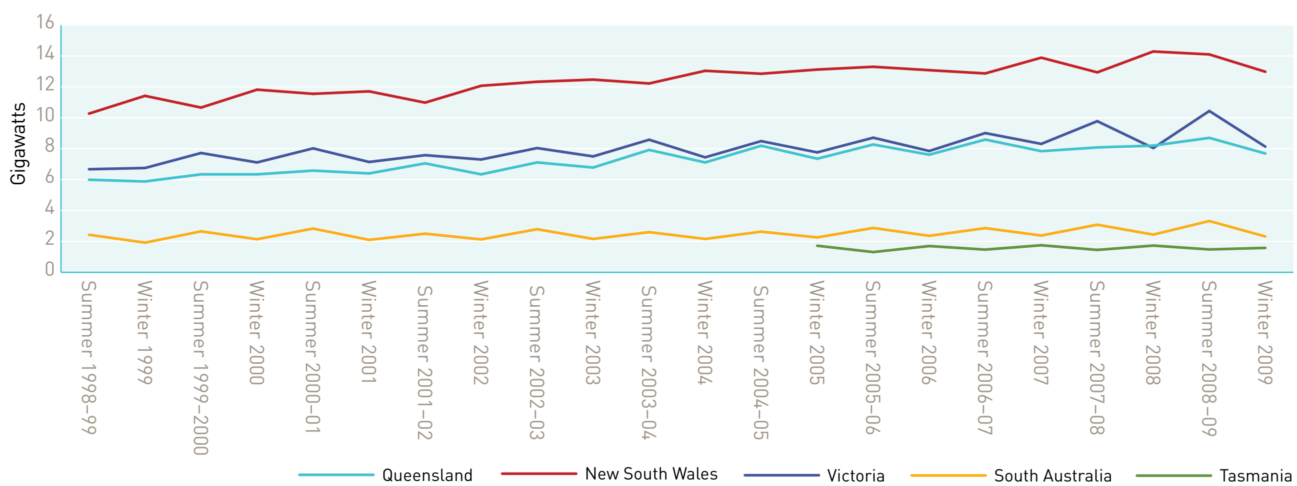
Table 2.2 Annual electricity consumption in the National Electricity Market (terawatt hours)

	QLD	NSW	VIC	SA	TAS[1]	SNOWY[2]	NATIONAL
2008–09	52.6	79.5	52.0	13.4	10.1		207.9
2007–08	51.5	78.8	52.3	13.3	10.3	1.6	208.0
2006–07	51.4	78.6	51.5	13.4	10.2	1.3	206.4
2005–06	51.3	77.3	50.8	12.9	10.0	0.5	202.8
2004–05	50.3	74.8	49.8	12.9		0.6	189.7
2003–04	48.9	74.0	49.4	13.0		0.7	185.3
2002–03	46.3	71.6	48.2	13.0		0.2	179.3
2001–02	45.2	70.2	46.8	12.5		0.3	175.0
2000–01	43.0	69.4	46.9	13.0		0.3	172.5
1999–2000	41.0	67.6	45.8	12.4		0.2	167.1

1. Tasmania entered the market on 29 May 2005.
2. The Snowy region was abolished on 1 July 2008. Electricity consumption formerly attributed to Snowy is now reflected in the New South Wales and Victorian data.

Source: AEMO.

Figure 2.3
Seasonal peak demand in the National Electricity Market



Sources: AEMO; AER.

Figures 2.4 and 2.5 show:

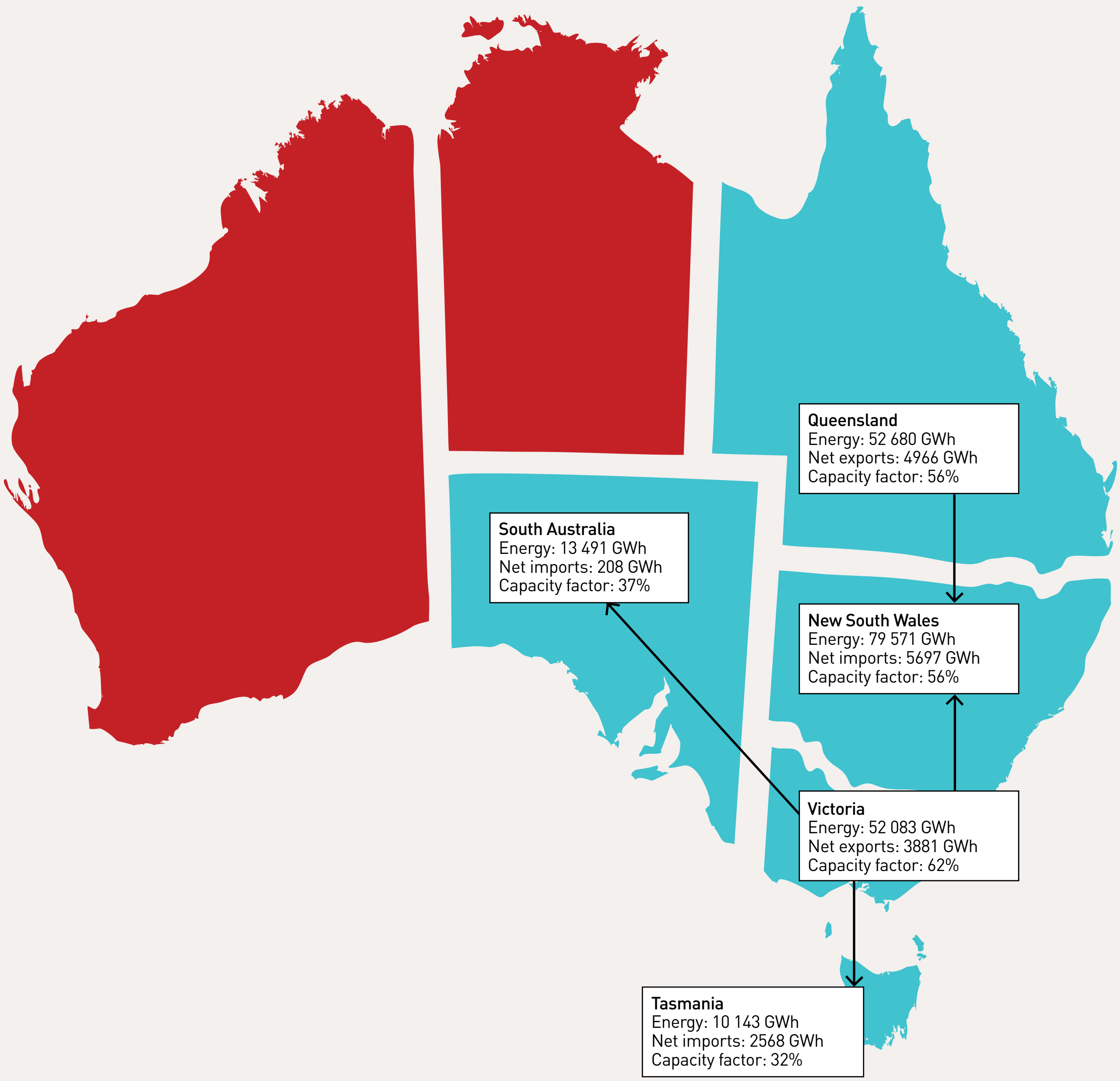
- New South Wales is a net importer of electricity. It relies on local baseload generation, but has limited peaking capacity at times of high demand.[9] This puts upward pressure on prices in peak periods, making imports a competitive alternative. New South Wales was importing over 10 per cent of its electricity requirements from 2002–03 to 2006–07, but this rate fell to around 7 per cent in 2007–08 and 2008–09.
- Victoria is a net exporter because it has substantial low cost baseload capacity.[10] This is reflected in the region's 62 per cent capacity factor—the highest for any region. In 2008–09 Victorian net electricity exports were equivalent to around 8 per cent of the state's consumption. Victoria tends to import mainly at times of peak demand when its regional capacity is stretched.

9 The New South Wales region gained additional hydroelectric peaking capacity following the abolition of the Snowy region on 1 July 2008.

10 The Victorian region gained additional hydroelectric peaking capacity on 1 July 2008 when the Murray generator was transferred from the Snowy region to Victoria.

Figure 2.4

Trade flows across National Electricity Market regions, 2008–09



GWh, gigawatt hour.

Notes:

'Energy' refers to electricity consumption.

'Capacity factor' refers to the proportion of local generation capacity in use.

Sources: AEMO; AER.

Figure 2.5
Interregional trade as percentage of regional energy consumption

Sources: AEMO; AER.

- Queensland's installed capacity exceeds its peak demand for electricity by around 3400 MW, making it a significant net exporter. Net exports from Queensland rose steadily from 2001–02, reaching around 13 per cent of the state's electricity consumption in 2006–07. Net exports fell to slightly below 10 per cent of consumption in 2008–09.
- South Australia, historically the most trade dependent region, imported over 25 per cent of its energy requirements in the early years of the NEM. This reflected the region's relatively higher fuel costs, resulting in high cost generation. New investment in generation—mostly in wind capacity—has significantly reduced South Australia's net imports since 2005–06. The state was a net exporter for the first time in 2007–08, but recorded net imports of around 2 per cent of electricity consumption in 2008–09.
- Tasmania has been a net importer since its interconnection with the NEM in 2006. It imported over 25 per cent of its electricity requirements in 2008–09, partly because drought constrained its ability to generate hydroelectricity.

2.4.1 Market separation

The NEM central dispatch process determines a separate spot price for each region of the NEM. In the absence of network constraints, interstate trade brings prices across the regions towards alignment. Due to transmission losses that occur when transporting electricity over distances, minor disparities across regional prices is normal. More significant price separation may occur if an interconnector is congested—for example, imports may be restricted when import requirements exceed an interconnector's design limits. Import capability may also be reduced when an interconnector is undergoing maintenance or an unplanned outage occurs. The availability of generation plant and the bidding behaviour of generators can also contribute to transmission congestion.

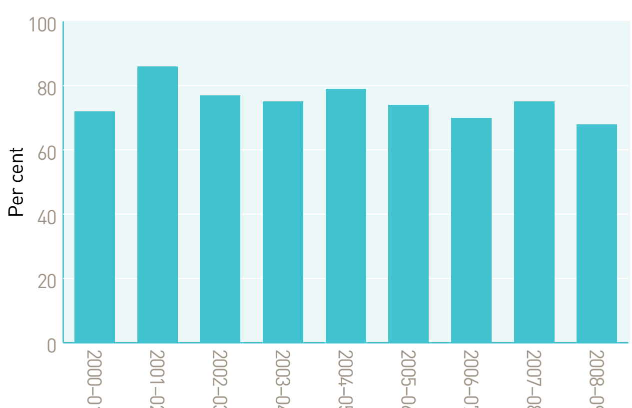
When congestion restricts a high demand region's ability to import electricity, prices in that region may spike. If, for example, low cost Victorian electricity is constrained from flowing into South Australia on a day of high demand, then more expensive South Australian generation—for example, local peaking plant—would need to be dispatched in place of imports. This would drive South Australian prices above those in Victoria.

The NEM is considered aligned when electricity can flow freely among all regions. There may still be minor price differences across regions due to loss factors that occur in the transport of electricity. Figure 2.6 indicates the mainland NEM regions operated as an 'integrated' market—with price alignment across the regions—for around 70 per cent of the time in 2008–09. This was the lowest rate of market alignment since the NEM commenced.

While the extent of alignment indicates how effectively the market is working, external factors such as lightning and other extreme weather may restrict interconnector flows. More generally, significant investment would be needed to remove all congestion, even under normal operating conditions. Research by the AER indicates the economic costs of transmission congestion are relatively modest given the scale of the market (see section 5.7).

Figure 2.6

Regional price alignment in the National Electricity Market as a percentage of trading hours



Note: Excludes Tasmania.

Sources: AEMO; AER.

2.4.2 Settlement residues

When there is price separation across regions, electricity tends to flow from lower priced regions to higher priced regions. The exporting generators are paid at their local regional spot price, while importing customers (usually energy retailers) must pay the higher spot price in the importing region. The difference between the price paid and the price received multiplied by the amount of electricity exported is called a settlement residue. These settlement residues accrue to the market operator (AEMO).

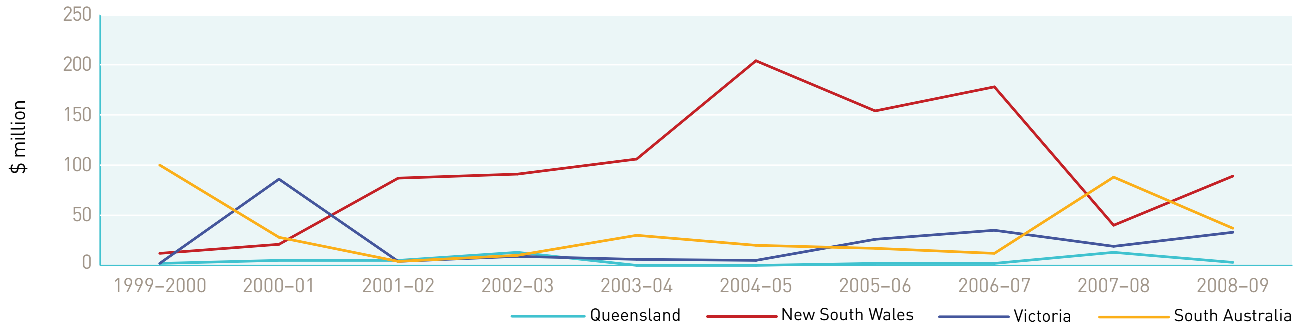
Figure 2.7 charts the annual accumulation of interregional settlement residues in each region. There is some volatility in the data, reflecting that a complex range of factors can contribute to price separation—for example, the availability of transmission interconnectors and generation plant, weather conditions and the bidding behaviour of generators.

New South Wales recorded settlement residues ranging from around $90 million to $200 million each year from 2001–02 to 2006–07. This range reflects the region's status as the largest importer of electricity (in dollar and volume terms) in the NEM, which can make it vulnerable to price separation events. New South Wales settlement residues fell by around 75 per cent in 2007–08 as a result of more benign market conditions, but rose in 2008–09. High prices on 31 October 2008 contributed around half of the region's settlement residues for the year.

Conversely, South Australian residues increased from a low base to almost $88 million in 2007–08 as a result of record summer prices in the region. While South Australian summer prices remained high in 2008–09, settlement residues fell closer to historical levels as summer prices also moved higher in Victoria. As net exporters, Queensland and Victoria tend not to accumulate large settlement residue balances.

Price separation creates risks for parties that contract across regions. To offer a risk management instrument, AEMO holds quarterly auctions to sell the rights to future residues. Section 5.7.3 explains the auction process.

Figure 2.7
Settlement residues in the National Electricity Market



Note: AEMO does not auction residues from Basslink, which is a market network service provider that earns income by arbitraging price differences between Tasmania and Victoria.

Sources: AEMO; AER.

2.5 National Electricity Market prices

The central dispatch process determines a spot price for each NEM region every 30 minutes. As noted, prices can vary across regions as a result of losses in transportation and transmission congestion, which sometimes restricts interregional trade.

The AER closely monitors the market and reports weekly on wholesale and forward market activity. It also publishes more detailed analyses of extreme price events. Figure 2.8 charts quarterly volume weighted average prices since the NEM commenced, while table 2.3 sets out annual volume weighted prices. Figure 2.9 provides a more detailed snapshot of weekly prices since January 2007.

Overall, prices tended to fall in the early years of the NEM—especially in Queensland and South Australia—following investment in new transmission and generation capacity. Drought, record peak demands and other factors led to average prices rising to record levels in 2006–07 and 2007–08.

Average prices in 2008–09 eased in all regions other than Tasmania (table 2.3). This reflected wetter conditions in parts of eastern Australia and, in 2009, the mildest winter on record in New South Wales, Victoria and South Australia. The milder winter temperatures drove lower winter peak demands in most regions. Combined winter peak demand for the NEM in 2009 was 32 094 MW—the lowest since 2006. This led to lower average winter prices in all mainland regions compared with last winter's averages, ranging from 26 per cent lower in New South Wales to 38 per cent lower in Victoria. In Tasmania, the average winter price increased by almost 70 per cent as a result of extreme price events in June 2009.

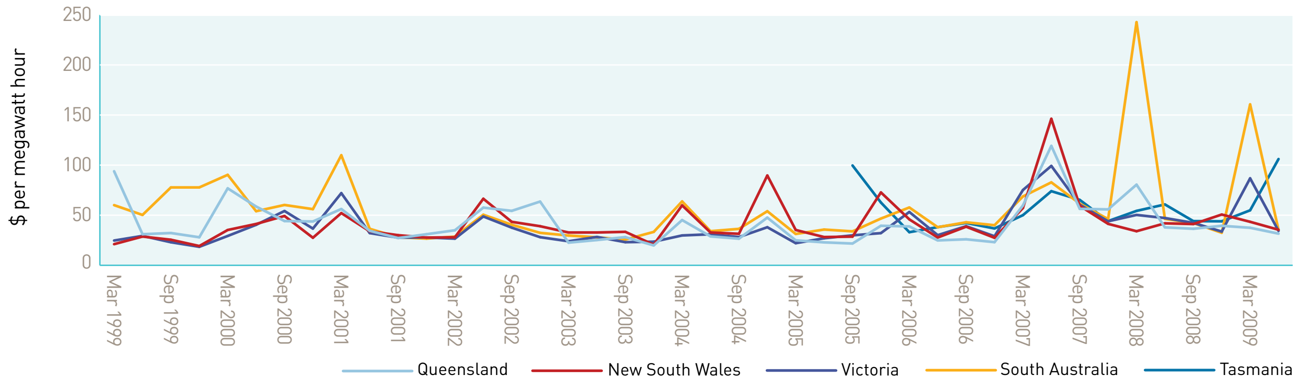
For the year overall, Queensland recorded its lowest prices since 2005–06. While prices fell sharply in South Australia, they remained high relative to those in other mainland regions.

Despite relatively benign market conditions, several extreme price events occurred in the first six months of 2009. These events occurred mostly in South Australia and Tasmania:

> Spot prices in South Australia exceeded $5000 per MWh on 27 occasions in the early months of 2009. These events typically occurred on days of extreme temperatures, which led to a tight supply–demand balance. The bidding strategies of AGL Energy on most of these occasions led to South Australian prices rising to near the market cap of $10 000 per MWh.

Figure 2.8

Quarterly volume weighted average prices—National Electricity Market



Sources: AEMO; AER.

Table 2.3 Weighted average spot electricity prices ($ per megawatt hour)

	QLD	NSW	VIC	SA	TAS[2]	SNOWY[3]
2008–09	36	43	49	69	62	
2007–08	58	44	51	101	57	31
2006–07	57	67	61	59	51	38
2005–06	31	43	36	44	59	29
2004–05	31	46	29	39		26
2003–04	31	37	27	39		22
2002–03	41	37	30	33		27
2001–02	38	38	33	34		27
2000–01	45	41	49	67		35
1999–2000	49	30	28	69		24
1999[1]	60	25	27	54		19

1. Six months to 30 June 1999.
2. Tasmania entered the market on 29 May 2005.
3. The Snowy region was abolished on 1 July 2008.

Source: AEMO.

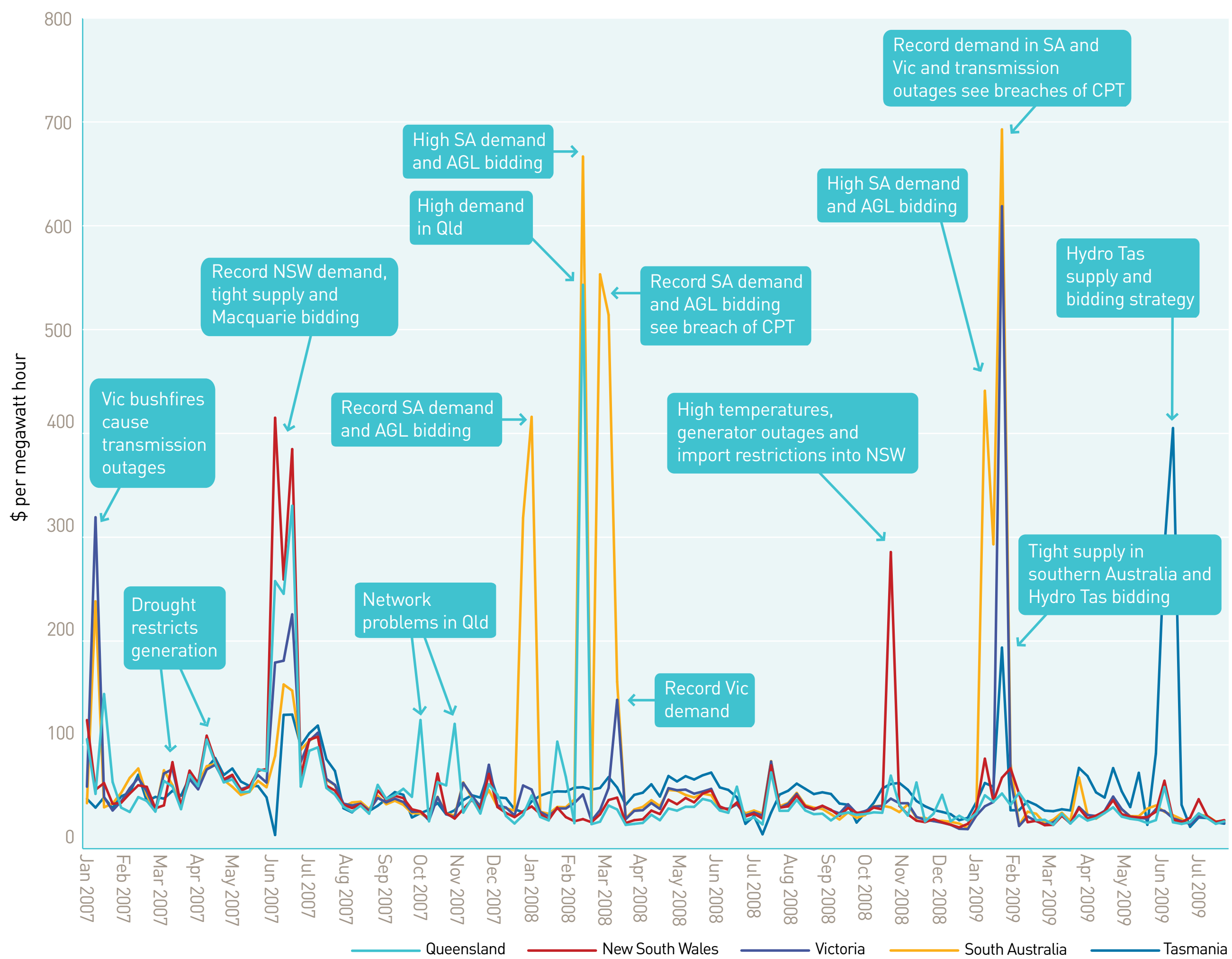
AGL Energy owns the Torrens Island power station, which accounts for 40 per cent of South Australia's generation capacity. Transmission limits on importing electricity from Victoria mean, under certain conditions, that AGL Energy can price a significant proportion of its capacity at around the market cap and be guaranteed some of the high-priced capacity will be dispatched. On 28 January 2009, for example, AGL Energy bid around 800 MW of capacity—around 65 per cent of Torrens Island's summer capacity rating—at close to the price cap of $10 000 per MWh.

> On 28 and 29 January 2009 extremely hot weather in South Australia and Victoria resulted in record demand. When combined with unplanned reductions in generation capacity and the outage of the Basslink interconnector on 29 January, this led to extreme prices and customer interruptions in both regions. The sustained high spot prices led to the cumulative price threshold being breached and pricing being administered in both regions for several days. The extreme temperatures also contributed to high prices in Tasmania on 29 and 30 January, with three spot prices in excess of $5000 per MWh.

- In June 2009 the spot price in Tasmania exceeded $5000 per MWh on 13 occasions. Reductions in output by Hydro Tasmania of its non-scheduled generation (mini hydro), in conjunction with its bidding strategy for the rest of its portfolio, was the significant driver in the majority of these outcomes.

In addition to high energy prices, Tasmania's frequency control ancillary services were very highly priced in April 2009. The prices of some services reached $5000 per MW for 13 hours over 1 April to 3 April, compared with typical prices of around $2 per MW. Further sustained high price events occurred through to 17 April.

Figure 2.9
National Electricity Market—average weekly prices



AGL, AGL Energy; CPT, cumulative price threshold; Macquarie, Macquarie Generation; Hydro Tas, Hydro Tasmania.

Note: Volume weighted prices.

Sources: AEMO; AER.


Origin Energy

2.6 Price volatility

Spot price volatility in the NEM reflects fluctuating supply and demand conditions. The market is sensitive to changes in these conditions, which can occur at short notice. Electricity demand can rise swiftly on a hot day, for example. Similarly, a generator or network outage can quickly increase regional spot prices. The sensitivity of the market to changing supply and demand conditions can result in considerable price volatility.

While figure 2.9 indicates volatility in weekly prices, it masks more extreme spikes that can occur during half hour trading intervals. On occasion, half hour spot prices approach the market cap of $10 000 per MWh. The main indicator of the incidence of extreme price events is the number of trading intervals during which the price is above $5000 per MWh (figures 2.10 and 2.11)

The AER draws on its market monitoring to publish weekly reports on market outcomes and more detailed reports when the electricity spot price exceeds $5000 per MWh.

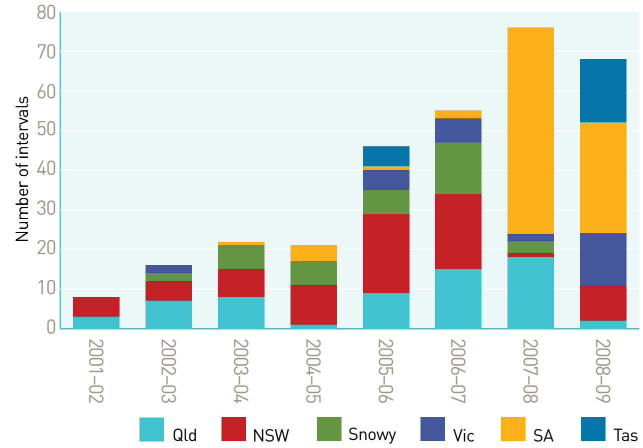
The incidence of trading intervals with prices above $5000 per MWh has increased since the NEM commenced (figure 2.10). The number of events rose significantly from 21 in 2004–05 to 76 in 2007–08. There were 68 events in 2008–09, of which 27 occurred in South Australia and 16 occurred in Tasmania in the first six months of 2009. The bidding behaviour of AGL Energy and Hydro Tasmania respectively contributed to many of these price outcomes. Figure 2.11 sets out the data on a quarterly basis.

Many factors can cause price spikes. While the cause of a high price event is not always clear, underlying causes may include:

- high demand that requires the dispatch of high cost peaking generators
- a generator outage that affects regional supply
- transmission network outages or congestion that restricts the flow of cheaper imports into a region
- a lack of effective competition in certain market conditions
- a combination of factors.

Figure 2.10

Trading intervals above $5000 per megawatt hour—National Electricity Market



Note: Each trading interval is a half hour.

Sources: AEMO; AER.

Table 2.4 summarises key features of extreme price events in 2008–09, noting the regions in which they occurred and indicating causes. The most common causes were:

- extreme weather
- network flow limits placed on particular transmission lines and interconnectors
- network outages
- generator bidding behaviour.

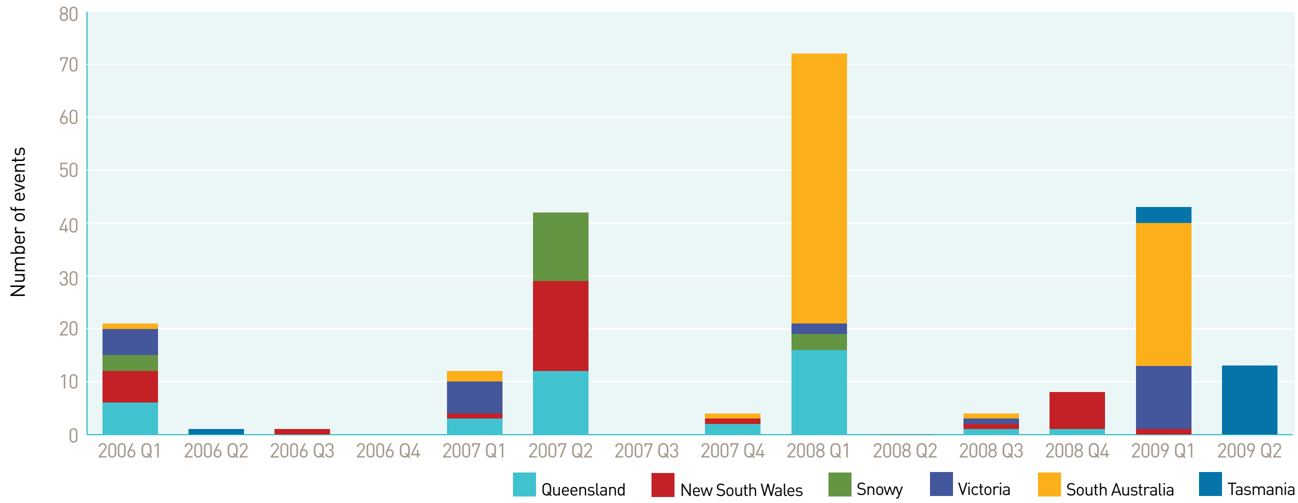
On one occasion, an error by AEMO contributed to high spot prices.

Price spikes can have a material impact on market outcomes. If prices approach $10 000 per MWh for just three hours in a year, the average annual price may rise by almost 10 per cent. Generators and retailers typically hedge against this risk by taking out contractual arrangements in financial markets (see chapter 3).

Extreme price events help to provide solutions to tight supply conditions. In particular, they create incentives to invest in peaking generation plant for operation during periods of peak demand.

Extreme price events may also create incentives for retailers to contract with customers to manage their demand in peak periods. A retailer may, for example, offer a customer financial incentives to reduce

Figure 2.11
Trading intervals above $5000 per megawatt hour (quarterly)—National Electricity Market



Sources: AEMO; AER.

consumption at times of high system demand, to ease price pressures. Effective demand management requires suitable metering arrangements to enable customers to manage their consumption. In 2009 AEMO estimated 195 MW of committed demand-side response in the NEM, with a further 559 MW of less firm capacity available.[11]

In April 2009 the Australian Energy Market Commission released a draft review of demand-side participation in the NEM.[12] It found the current framework allows for efficient participation, but also found a few minor barriers that a change in the Electricity Rules will address.

At the small customer level, the Council of Australian Governments agreed in 2007 to a progressive rollout of 'smart' electricity meters (where the benefits outweigh costs) to encourage demand-side response (see section 6.8.2).

2.7 Market investigations

The AER monitors activity in the spot market to screen for issues of non-compliance with the Electricity Rules. In addition to reporting on all extreme price events in the NEM, it conducts more intensive investigations where this is warranted.

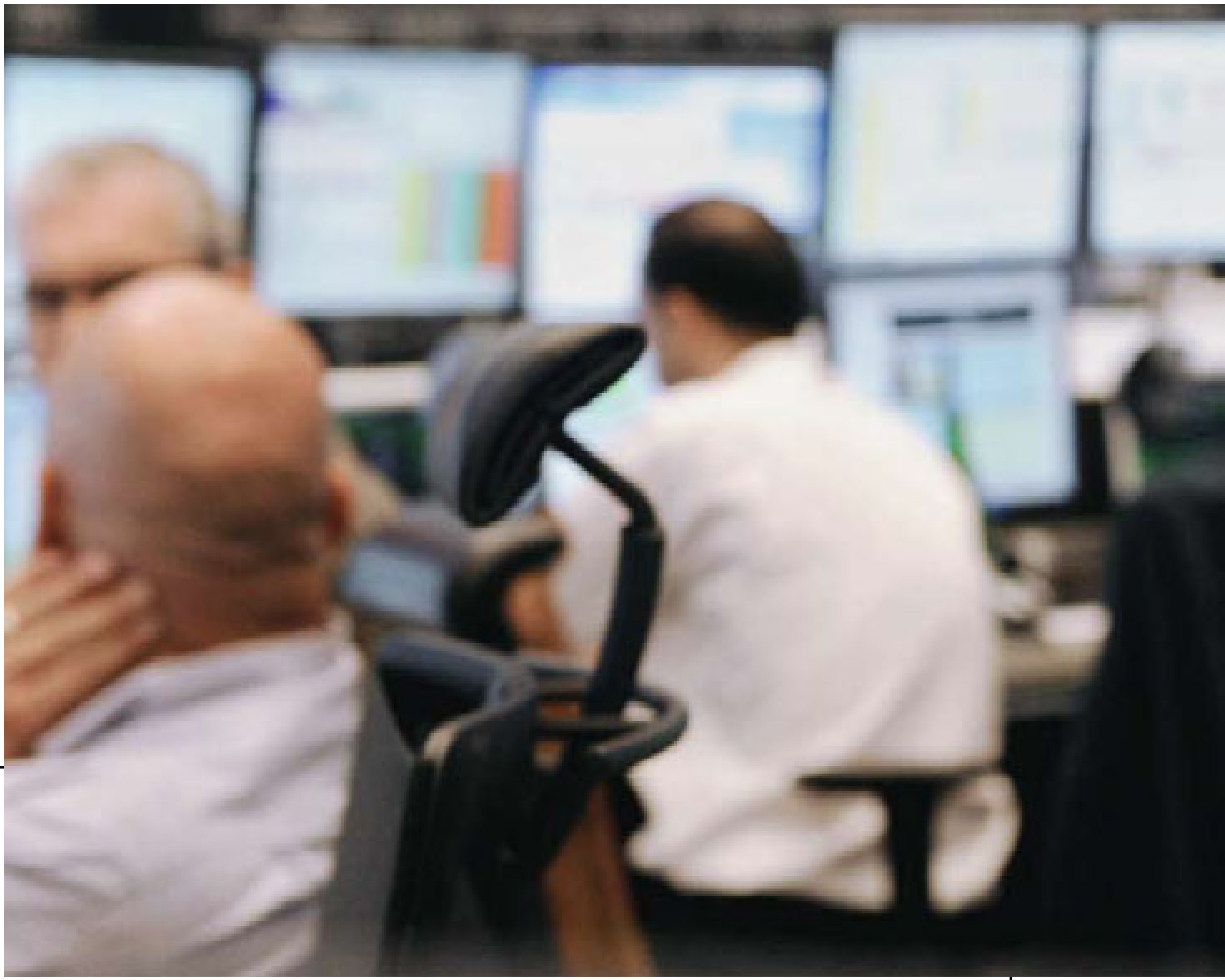
In 2008 the AER launched separate investigations into whether Stanwell (a Queensland generator) and AGL Energy (in relation to its South Australian generators) acted 'in good faith', as contemplated under the Rules, when they rebid capacity during periods of high prices in early 2008. While bidding capacity at high prices is not a breach of the Rules, generators are required to make capacity offers and any rebids in 'good faith.' In its investigation findings published on 12 May 2009, the AER found that AGL Energy's bidding was not in breach of the Rules.

The AER investigation into the rebidding behaviour of Stanwell led to it instituting proceedings in the Federal Court, Brisbane. The AER has alleged that several of Stanwell's rebids of offers to generate electricity on 22 and 23 February 2008 were not made in 'good faith'. The AER is seeking orders including declarations, civil penalties, a compliance program and costs. The matter has been set down for trial in June 2010.

11 AEMO, *Electricity statement of opportunities*, Melbourne, 2009, p. 67.
12 AEMC, *Demand-side participation in the National Electricity Market, draft report*, Sydney, April 2009.

Table 2.4 **Price events above $5000 per megawatt hour—National Electricity Market, 2008–09**

DATE OR PERIOD	REGIONS	NO. OF EVENTS	CAUSES IDENTIFIED BY THE AER
23 July 2008	New South Wales, Queensland, Victoria and South Australia	4	Unplanned outages of two Hazelwood to Loy Yang transmission lines in the LaTrobe Valley (Victoria) left only one line in operation between Loy Yang and Tasmania and the rest of the market. Very high frequency control ancillary services were required to manage this. In addition, generation at Loy Yang was constrained and exports from Tasmania via Basslink were reduced to zero.
31 October 2008	New South Wales	7	High temperatures in Sydney led to above forecast demand. Around 4300 MW of generation was unavailable (mostly unplanned) and import capability into New South Wales was also lower than forecast.
20 November 2008	Queensland	1	Unplanned reductions in Queensland generator availability occurred, in combination with low import capability and higher than forecast demand. Millmerran Energy Trader and Stanwell Corporation then rebid low priced capacity at close to the price cap.
13 January 2009	South Australia	8	AGL's bidding behaviour, high temperatures and high demand at a time of lower than forecast import capability. This required the dispatch of high priced generation.
15 January 2009	New South Wales	1	Temperatures in western Sydney reached 43 degrees, leading to record summer demand. In addition, around 2100 MW of New South Wales generation was unavailable and import capability was reduced as a result of planned network outages. New South Wales generators reacted to the tight supply–demand balance by rebidding capacity into higher price bands.
19 January 2009	South Australia	6	For five trading intervals, high demand caused by extreme temperatures led to the dispatch of high priced capacity. Rebidding by AGL Energy shifted a significant amount of required capacity from prices below $101 per MWh to the price cap. Dispatch of this capacity set the spot price for two and a half hours. In the other interval, an incorrect input into the dispatch process led to the spot price exceeding $5000 per MWh.
28–29 January 2009	South Australia and Victoria	24	Record demand (due to extreme weather in South Australia and Victoria), combined with unplanned reductions in generation capacity and the unplanned outage of the Basslink interconnector on 29 January, required the dispatch of high priced generation. The extreme conditions led to customer interruptions in both regions on 29 January. The sustained high prices led to the cumulative price threshold being breached and pricing being administered in both regions for several days.
29–30 January 2009	Tasmania	3	On 29 January one spot price exceeded $5000 per MWh when Hydro Tasmania rebid a significant amount of capacity from below $1600 per MWh to above $5000 per MWh. On 30 January two spot prices exceeded $5000 per MWh as a result of tight supply in southern Australia combined with high priced generation offers in Tasmania.
31 March 2009	South Australia	1	An unplanned outage at South Australia's largest generator—Northern power station—led to the dispatch of high priced generation.
1 June 2009	Tasmania	1	Hydro Tasmania rebid a significant amount of capacity from prices below $300 per MWh to prices above $9000 per MWh. It can set the spot price in Tasmania, even at moderate levels of demand.
10–19 June 2009	Tasmania	12	Eleven events occurred when Hydro Tasmania made sudden and repeated reductions in the output of its non-scheduled generators, requiring the dispatch of other generation in its portfolio. At the same time, Hydro Tasmania made a step change in the amount of capacity it was offering at prices above $5000 per MWh. The other event occurred when Hydro Tasmania bid a significant amount of capacity at above $5000 per MWh for the trading interval. The sustained high prices caused a breach of the cumulative price threshold for the first time ever in Tasmania, and led to administered pricing for several days.



3 ELECTRICITY FINANCIAL MARKETS

Thomas Lohnes (Getty Images)

Spot price volatility in the National Electricity Market can cause significant risk to physical market participants. While generators face a risk of low prices having an impact on earnings, retailers face a complementary risk that prices may rise to levels they cannot pass on to their customers. Market participants commonly manage their exposure to volatility by entering financial contracts that lock in firm prices for the electricity they intend to produce or buy in the future.

3 ELECTRICITY FINANCIAL MARKETS

This chapter considers:

- the structure of electricity financial markets in Australia, including over-the-counter markets and the exchange traded market on the Sydney Futures Exchange
- financial market instruments traded in Australia
- liquidity indicators for Australia's electricity financial markets, including trading volumes, open interest, changes in the demand for particular instruments, changes in market structure, and vertical integration in the underlying electricity wholesale market
- price outcomes on the Sydney Futures Exchange
- other mechanisms to manage price risk in the wholesale electricity market.

While the Australian Energy Regulator (AER) does not regulate the electricity derivatives markets, it monitors the markets because they have significant links with wholesale and retail activity. Levels of contracting and forward prices in the financial markets can, for example, affect generator bidding in the National Electricity Market (NEM). Similarly, financial markets can influence retail competition by providing a means for new entrants to manage price risk. More generally, the markets create price signals for energy infrastructure investors and provide a means to secure the future earnings streams needed to underpin investment.

3.1 Financial market structure

Financial markets offer contractual instruments (derivatives) to manage forward price risk in wholesale electricity markets.[1] While the derivatives provide a means of locking in future prices, they do not give rise to the physical delivery of electricity.

The participants in electricity derivatives markets include generators, retailers, financial intermediaries and speculators such as hedge funds. Brokers facilitate many transactions between contracting participants.

In Australia, two distinct electricity financial markets support the wholesale electricity market:

> over-the-counter (OTC) markets, comprising direct transactions between counterparties, often with the assistance of a broker

> the exchange traded market on the Sydney Futures Exchange (SFE).[2]

3.1.1 Over-the-counter markets

The OTC markets allow wholesale electricity market participants to enter into confidential contracts to manage risk. Many OTC contracts are bilateral arrangements between generators and retailers, which face opposing risks in the wholesale electricity market. Other OTC contracts are arranged with the assistance of brokers that post bid (buy) and ask (sell) prices on behalf of their clients. In 2008–09 around 62 per cent of OTC contracts were arranged through a broker.[3] Financial intermediaries and speculators add market depth and liquidity by quoting bid and ask prices, taking trading positions and taking on market risk to facilitate transactions.

Most OTC transactions are documented under the International Swaps and Derivatives Association Master Agreement, which provides a template of standard terms and conditions, including terms of credit, default provisions and settlement arrangements. While the template creates considerable standardisation in OTC contracts, market participants usually modify contract terms to suit their needs. This means OTC products can provide flexible solutions through a variety of structures.

The *Financial Services Reform Act 2001* (Cwlth) includes disclosure provisions that relate to OTC markets. In general, however, the bilateral nature of OTC markets tends to make volume and price activity less transparent than in the exchange traded market.

3.1.2 Exchange traded futures

Derivative products such as electricity futures and options are traded on registered exchanges. In Australia, electricity futures products developed by d-cyphaTrade are traded on the SFE. Participants (licensed brokers) buy and sell contracts on behalf of clients that include generators, retailers, speculators such as hedge funds, and banks and other financial intermediaries.

Normal trades on the SFE are made by matching buy and sell offers for contracts through the exchange. Prices struck through normal trades are used to determine end-of-day contract settlement prices.

Block trades are negotiated bilaterally—either via brokers or directly between counterparties—before being registered as a centrally cleared contract position on the SFE. This trading mechanism provides market participants with the flexibility to negotiate deals bilaterally yet receive the risk mitigation benefits of contracting with the SFE Clearing Corporation. Similarly, *exchange for physical* contracts enable participants to eliminate credit default risk by converting OTC contracts into exchange traded contracts. Participants are limited to combinations of products specified on the SFE. Block trades and exchange for physical contract prices are not used to determine end-of-day contract settlement prices.

1 Spot prices in the wholesale market can vary between –$1000 per megawatt hour (MWh) (the price floor) and $10 000 per MWh (the price cap). To manage risk resulting from volatility in the spot price, retailers can hedge their portfolios by purchasing financial derivatives that lock in firm prices for the volume of energy they expect to purchase in the future. This eliminates exposure to future price volatility for the quantity hedged and provides greater certainty on profits. Similarly, a generator can hedge against low spot prices.

2 In 2006 the Sydney Futures Exchange merged with the Australian Stock Exchange. The merged business operates as the Australian Securities Exchange.

3 AFMA, *2008 Australian financial markets report*, Sydney, 2008 and supporting 'Full report data' spreadsheet.

Figure 3.1 shows that over half of trades processed through the SFE are block trades. Only a small percentage of trades are exchange for physical contracts.

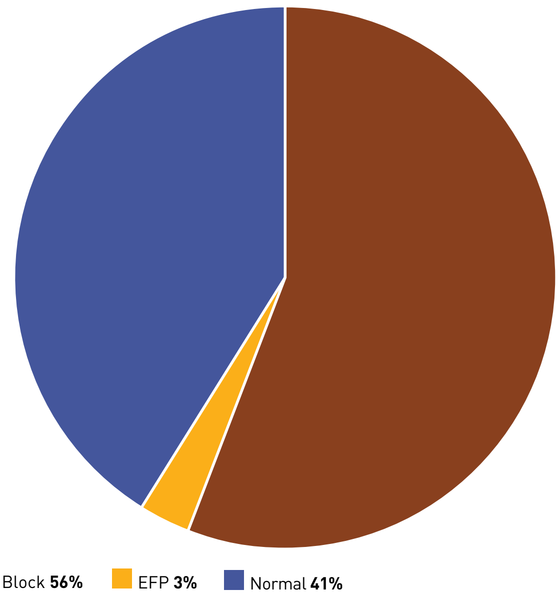
Exchange trading on the SFE differs from OTC trading in a number of ways:

> Exchange traded derivatives are highly standardised in terms of contract size, minimum allowable price fluctuations, maturity dates and load profiles. The product range in OTC markets tends to be more diverse and includes 'sculpted' products.
> Exchange trades are multilateral and publicly reported, giving rise to greater market transparency and price discovery than in the OTC market.
> Unlike OTC transactions, exchange traded derivatives are settled through a centralised clearing house, which is the central counterparty to transactions and applies daily mark-to-market cash margining to manage credit default risk.[4] Exchange clearing houses, such as the SFE Clearing Corporation, are regulated and are subject to prudential requirements to mitigate credit default risks. This offers an alternative to OTC trading, where trading parties rely on the credit worthiness of electricity market counterparties. More generally, liquidity issues can arise in OTC markets if trading parties reach or breach their credit risk limits with other OTC counterparties (for example, breaches due to revaluations of existing bilateral hedge obligations or credit downgrades of counterparties).

3.1.3 Regulatory framework

Electricity financial markets are subject to a regulatory framework that includes the *Corporations Act 2001* (Cwlth) and the *Financial Services Reform Act 2001* (Cwlth). The Australian Securities and Investments Commission is the principal regulatory agency. Amendments to the Corporations Act in 2002 extended insider trading legislation and the disclosure principles expected of securities and equity related futures to electricity derivative contracts.

Figure 3.1
Composition of trading in electricity derivatives —Sydney Futures Exchange



EFP, exchange for physical.
Source: d-cyphaTrade.

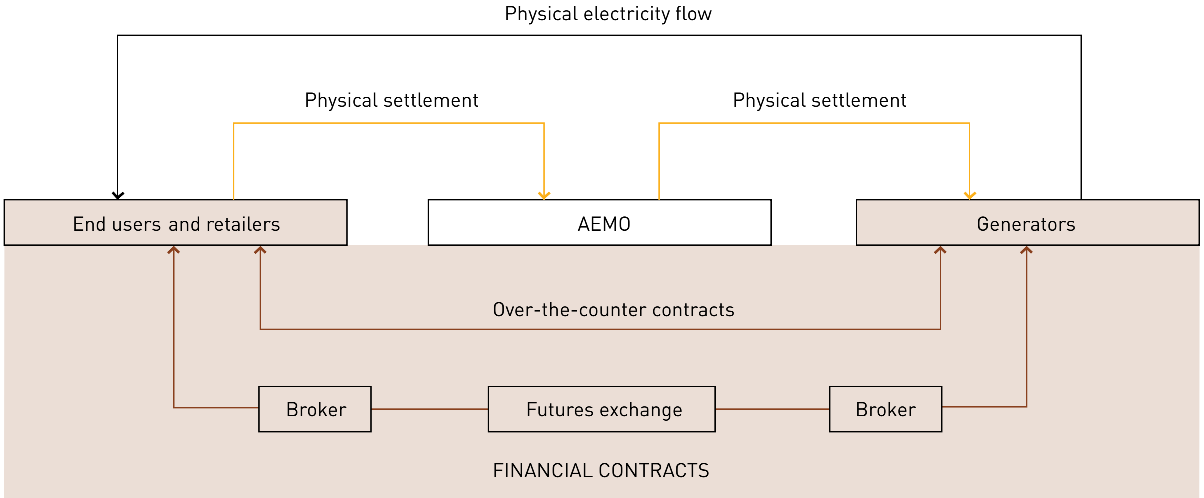
Market participants must also comply with standards issued by the Australian Accounting Standards Board (AASB). In particular, AASB 139 requires companies' hedging arrangements to pass an effectiveness test to qualify for hedge accounting. The standards also outline financial reporting obligations such as mark-to-market valuation of derivative portfolios, and they require financial derivative revaluations to be benchmarked against observable market prices and adjusted for embedded credit default risk.

Further regulatory overlays in electricity derivative markets include the following:

> The Corporations Act requires OTC market participants to have an Australian Financial Services licence or exemption.
> Exchange based transactions are subject to the operating rules of the SFE.

4 Mark-to-market refers to the valuation technique whereby unrealised profit or loss from a derivative position is determined (and reported in financial statements) by reference to prevailing market prices.

Figure 3.2
Relationship between the National Electricity Market and financial markets



AEMO, Australian Energy Market Operator.

Source: Energy Reform Implementation Group.

3.1.4 Relationship with the National Electricity Market

Figure 3.2 illustrates the relationship between the financial markets and the physical trading of electricity in the NEM. Trading and settlement in the NEM occur independently of financial market activity, although a generator's exposure in the financial market can affect its bidding behaviour in the NEM. Similarly, a retailer's exposure to the financial market may affect the pricing and availability of supply contracts that it offers to customers.

The settlement process in the NEM, combined with hedging contracts, gives rise to circular cash flows or contracts for difference payments. The NEM settlement arrangements also allow for re-allocations, whereby an off-market financial commitment (such as a hedge contract between participants) is netted off against settlements in the physical market. This mechanism has not been widely used.

The Australian Energy Market Commission (AEMC) is reviewing the potential for further integrating the wholesale and financial electricity markets to minimise circular cash flows and reduce the prudential burden on market participants.[5] Options include:

- allowing a NEM participant to offset its prudential requirements using its futures contract margin payments
- using futures prices to determine a participant's prudential obligations, rather than relying on historical wholesale price outcomes.

3.2 Financial market instruments

The financial market instruments traded in the OTC and exchange traded markets are called derivatives because they derive their value from an underlying asset—in this case, electricity traded in the NEM. The derivatives give rise to cash flows from the differences between the contract price of the derivative and the spot price of electricity. The prices of these instruments reflect the expected spot price, plus premiums to cover credit default risk and market risk.

5 AEMC, *Review into the role of hedging contracts in the existing NEM prudential framework, framework and issues paper*, Sydney, March 2009.

Table 3.1 Common electricity derivatives in over-the-counter and Sydney Futures Exchange markets

INSTRUMENT	DESCRIPTION
Forward contracts	An agreement to exchange the NEM spot price in the future for an agreed fixed price. Forwards are called swaps in the OTC markets and futures on the SFE.
> Swaps (OTC market)	OTC swap settlements are typically paid or received weekly in arrears (after the spot price is known) based on the difference between the spot price and the previously agreed fixed price.
> Futures (SFE)	SFE electricity futures and options settlements are paid or received daily based on mark-to-market valuations. SFE futures are finally cash settled against the average spot price of the relevant quarter.
Options	A right—without obligation—to enter into a transaction at an agreed price in the future (exercisable option) or a right to receive cash flow differences between an agreed price and a floating price (cash settled option).
> Cap	A contract through which the buyer earns payments when the pool price exceeds an agreed price. Caps are typically purchased by retailers to place a ceiling on their effective pool purchase price in the future.
> Floor	A contract through which the buyer earns payments when the pool price is less than an agreed price. Floors are typically purchased by generators to ensure a minimum effective pool sale price in the future.
> Swaptions or futures options	An option to enter a swap or futures contract at an agreed price and time in the future.
> Asian options	An option through which the payoff is linked to the average value of an underlying benchmark (usually the NEM spot price) during a defined period.
> Profiled volume options for sculpted loads	A volumetric option that gives the holder the right to purchase a flexible volume in the future at a fixed price.

NEM, National Electricity Market; OTC, over-the-counter; SFE, Sydney Futures Exchange

Table 3.1 lists some of the derivative instruments available in the OTC and exchange traded markets. Common derivatives to hedge exposure to the NEM spot price are forwards (such as swaps and futures) and options (such as caps). Each provides the buyer and seller with a fixed price—and, therefore, a predictable future cash flow—on purchase/sale of the derivative or, in the case of an option, if the option is exercised. The following section describes some instruments in more detail.

3.2.1 Forward contracts

Forward contracts—called swaps in the OTC market and futures on the SFE—allow a party to buy or sell a given quantity of electricity at a fixed price over a specified time. Each contract relates to a nominated time of day in a particular region. On the SFE, contracts are quoted for quarterly base and peak contracts, for up to four years into the future.[6]

A retailer may, for example, enter an OTC contract to buy 10 megawatts (MW) of Victorian peak load in the fourth quarter of 2009 at $40 per megawatt hour (MWh). During that quarter, whenever the Victorian spot price for any interval from 7.00 am to 10.00 pm Monday to Friday settles above $40 per MWh, the seller (which might be a generator or financial intermediary) pays the difference to the retailer. Conversely, the retailer pays the difference to the seller when the price settles below $40 per MWh. In effect, the contract locks in a price of $40 per MWh for both parties.

A typical OTC swap may involve a retailer and generator contracting with one another—directly or through a broker—to exchange the NEM spot price for a fixed price, thereby reducing market risk for both parties. On the exchange traded market, the parties (generators, retailers, financial intermediaries and speculators) that buy and sell futures contracts through SFE brokers remain anonymous. The SFE Clearing Corporation is the central counterparty to SFE transactions. As noted, exchange trading is more transparent in terms of prices and trading volumes.

6 A peak contract relates to the hours from 7.00 am to 10.00 pm Monday to Friday, excluding public holidays. An off-peak contract relates to hours outside that period. A flat price contract covers both peak and off-peak periods.

While the SFE tends to offer a narrower range of instruments than offered by the OTC market,[7] up to 3000 futures and options products are listed on the SFE at any time.

3.2.2 Options

While a swap or futures contract gives price certainty, it locks the parties into defined contract prices with defined volumes, without an opt-out provision if the underlying market moves adversely to the agreed contract price. An option gives the holder the right—without obligation—to enter a contract at an agreed price, volume and term in the future. The buyer pays a premium to the option seller for this added flexibility.

An exercisable call (put) option gives the holder the right to buy (sell) a specified volume of electricity futures (or swaps) in the future at a predetermined strike price—either at any time up to the option's expiry (an 'American' option) or at expiry (a 'European' option). A retailer that buys a call option to protect against a rise in NEM forward contract prices, for example, can later abandon that option if forward prices do not rise as predicted. The retailer could then take advantage of the lower prevailing forward (or NEM spot) price.

Commonly traded options in the electricity market are caps, floors and collars.[8] A cap allows the buyer—for example, a retailer with a natural short exposure to spot prices—to set an upper limit on the price that they will pay for electricity while still being able to benefit if NEM prices are lower than anticipated. A cap at $300 per MWh (the cap most commonly traded in Australia), for example, ensures a buyer using the cap to hedge a natural 'short' retail spot market position will pay no more than $300 per MWh for the agreed volume of electricity, no matter how high the spot price may rise. In Australia, a cap is typically sold for a nominated quarter—for example, January–March 2010. Base cap contracts are listed two years ahead on a quarterly basis on the SFE and regularly trade in full year strips (comprising a bundle of the four quarters of the year).

By contrast, a floor contract struck at $40 per MWh will ensure a minimum price of $40 per MWh for a floor buyer such as a generator with a natural 'long' exposure to spot prices. Retailers typically buy caps to secure firm maximum prices for future electricity purchases, while generators use floors to lock in a minimum price to cover future generation output. A collar contract combines a cap and floor to set a price band in which the parties agree to trade electricity in the future.

The range and diversity of products is expanding over time to meet the requirements of market participants.

3.2.3 Flexible volume instruments

Instruments such as swaps and options are used to manage NEM price risk for fixed quantities of electricity. But the profile of electricity loads varies according to the time of day and the weather conditions. This variation can result in significant volume risk, in addition to price risk. In particular, it can leave a retailer over-hedged or under-hedged, depending on actual levels of electricity demand. Conversely, a retailer can also earn windfall gains.

Structured products such as flexible volume contracts are used to manage volume risks. These sculpted products, which are traded in the OTC market, enable the buyer to vary the contracted volume on a pre-arranged basis. The buyer pays a premium for this added flexibility.

7 The OTC market can theoretically support an unlimited range of bilaterally negotiated product types.

8 While caps and floors are technically options—they are effectively a series of half-hourly options—they are typically linked to the NEM spot price and are automatically exercised when they deliver a favourable outcome. Other options (such as swaptions) are generally linked to forward prices, and the buyer must nominate whether the option is to be exercised.

Table 3.2 **Trading volume in electricity derivatives—Sydney Futures Exchange**

	2002–03	2003–04	2004–05	2005–06	2006–07	2007–08	2008–09
Total trade (TWh)	7	29	24	55	243	241	301
Increase (per cent)		341	–19	129	345	–1	25

TWh, terawatt hours.

Source: d-cyphaTrade.

3.3 Financial market liquidity

The effectiveness of financial markets in providing risk management services depends on the extent to which they offer the products that market participants require. Adequate market liquidity is critical. In electricity financial markets, liquidity relates to the ability of participants to transact a standard order within a reasonable timeframe to manage their load and price risk, using reliable quoted prices that are resilient to large orders, and with sufficient market participants and trading volumes to ensure low transaction costs.

Indicators of liquidity in the electricity derivatives market include:

- the volume and value of trade
- open interest in contracts
- the transparency of pricing
- the number and diversity of market participants
- the number of market makers and the bid–ask spreads they quote
- the number and popularity of products traded
- the degree of vertical integration between generators and retailers
- the presence of financial intermediaries in the market.

This chapter focuses mainly on liquidity indicators relating to trading volumes, but also considers open interest data, pricing transparency, changes in the demand for particular derivative products, changes in the financial market's structure, and vertical integration.

3.4 Trading volumes in Australia's electricity derivative market

There is comprehensive data on derivative trading on the SFE, which is updated daily in real time. The OTC market is less transparent, but periodic survey data provide some indicators of trading activity.

3.4.1 Sydney Futures Exchange

Financial market vendors such as d-cyphaTrade publish data on electricity derivative trading on the d-cypha SFE electricity futures market. Table 3.2 and figure 3.3 illustrate volume trends. Trading levels accelerated from 2005–06, with 345 per cent growth in 2006–07. They flattened in 2007–08, but again rose in 2008–09, when they exceeded 300 terawatt hours (TWh) for the first time (despite relatively flat underlying electricity demand).

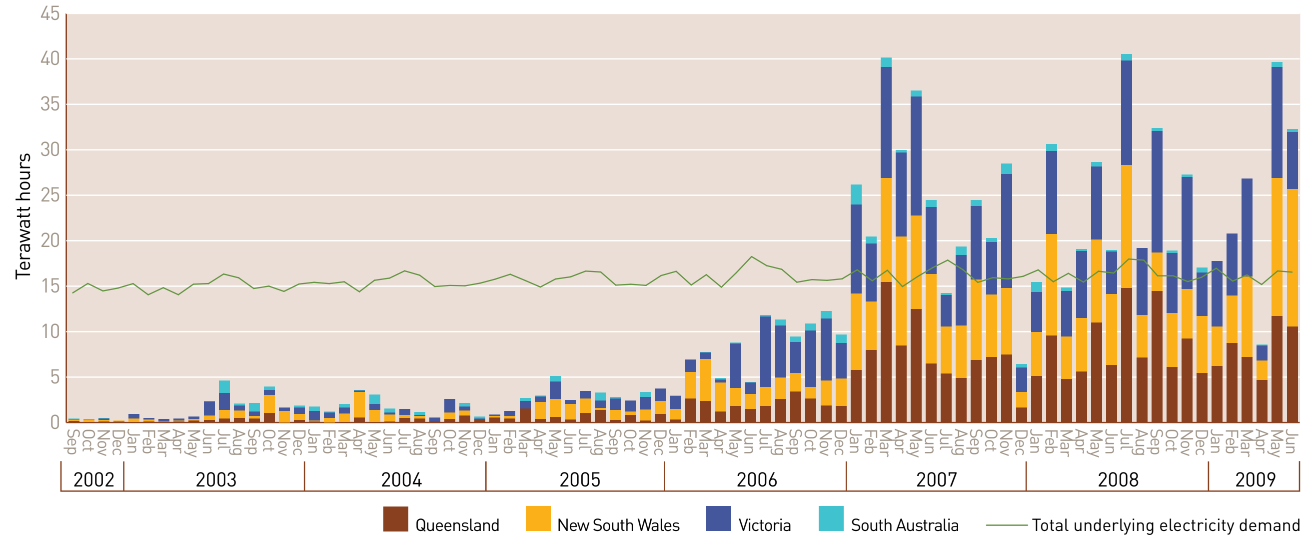
In 2008–09 Queensland accounted for 35 per cent of traded volume, followed by Victoria (34 per cent) and New South Wales (30 per cent). Liquidity in South Australia has remained low since 2002, accounting for around only 1 per cent of volume (figure 3.4).

Trading on the SFE comprises a mix of futures (first listed in September 2002) and caps and other options (first listed in November 2004). Trading in options increased from around 16 per cent of traded volumes in 2007–08 to around 38 per cent in 2008–09.[9]

Figure 3.5 shows trading volumes for 2010 contracts recorded a step increase from around August 2008, with significant activity in options. The swing towards options applied to all products and continued throughout 2008–09. It might have reflected the need

9 d-cyphaTrade, *Energy focus, FY review 2008/2009*, Sydney, 2009.

Figure 3.3
Regional trading volume in electricity derivatives—Sydney Futures Exchange



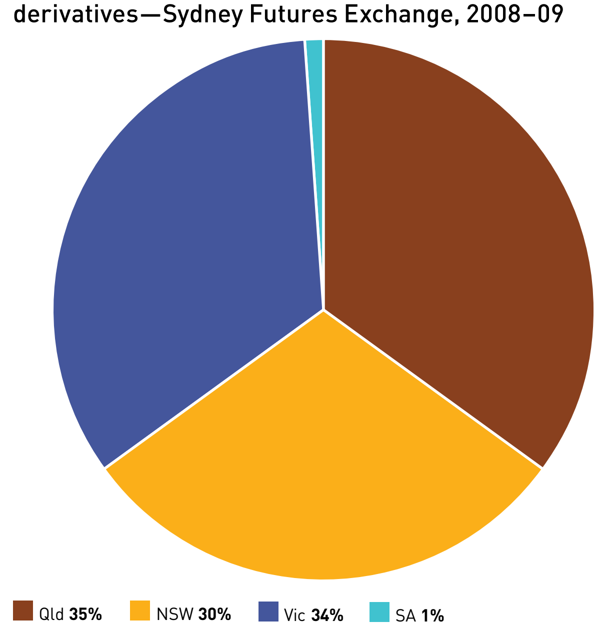
Source: d-cyphaTrade.

for market participants to hedge in an increasingly uncertain market, particularly given the planned introduction of the Carbon Pollution Reduction Scheme (CPRS) in 2010. Trading in options remained strong, however, despite the Australian Government's decision to delay introducing the CPRS to 2011.

During 2008-09 the d-cypha SFE electricity options market grew to become one of the largest electricity options markets in the world, trading 115 TWh—the equivalent of 58 per cent of underlying NEM demand.

Figure 3.6 shows the composition of futures and options trade on the SFE in 2008–09 by maturity date. The SFE trades quarterly futures and options out to four years ahead, compared with three years in many overseas markets.[10] Liquidity was highest for contracts with an end date between six months and two years from the trade date. Only a relatively small number of open contracts have an end date beyond 2.5 years. This timing is consistent with the trading preferences of speculators and the time horizons of electricity retail contracts, of which the majority are negotiated for one year and which rarely run beyond three years. Some retailers do not lock in forward hedges beyond the term of existing customer contracts.

Figure 3.4
Regional shares of trading volume in electricity derivatives—Sydney Futures Exchange, 2008–09

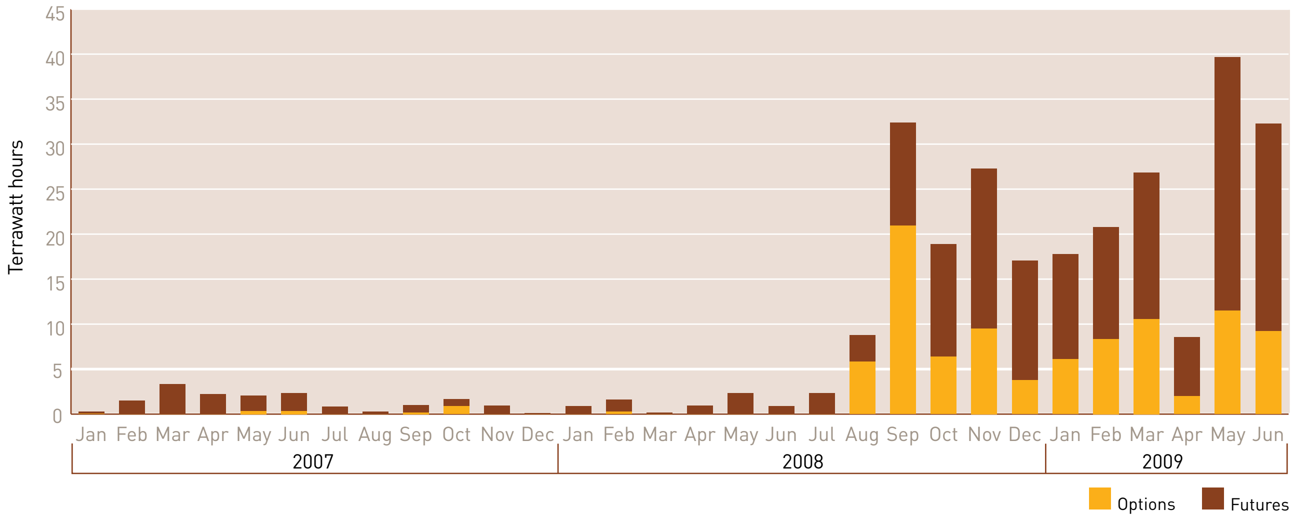


Source: d-cyphaTrade.

10 See, for example, www.eex.de (Germany) or www.powernext.fr (France).

Figure 3.5

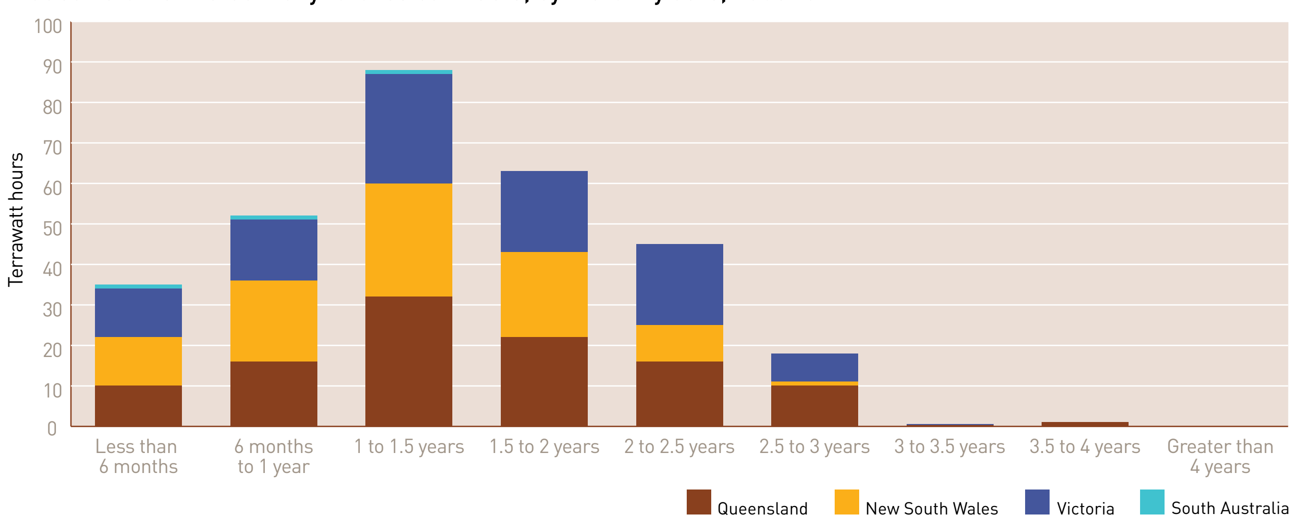
Traded volume for 2010 contracts—Sydney Futures Exchange



Source: d-cyphaTrade.

Figure 3.6

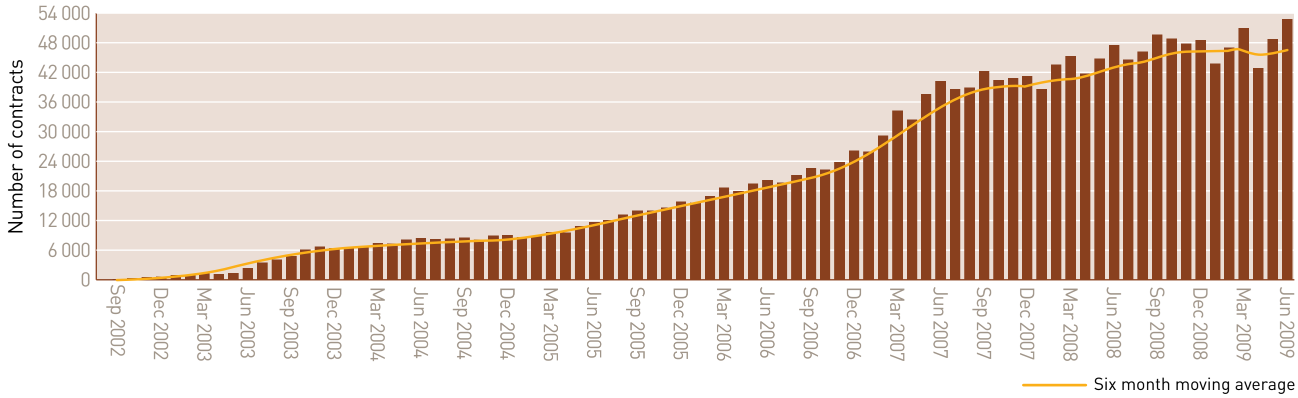
Traded volume in electricity futures contracts, by maturity date, 2008–09



Source: d-cyphaTrade.

Figure 3.7 illustrates open interest in electricity futures on the SFE over time. Open interest refers to the total number of futures and option contracts that have been entered and remain open—that is, have not been exercised, expired or closed out—at a point in time. An increase in open interest typically accompanies a rise in trading volumes and reflects underlying demand growth. As figure 3.7 illustrates, open interest for SFE electricity futures increased from 2002 to late 2008, before levelling out over the remainder of 2008–09. The number of open contracts rose from around zero in 2002 to over 52 000 in June 2009.

Figure 3.7
Open interest on the Sydney Futures Exchange



Source: d-cyphaTrade.

3.4.2 Over-the-counter markets

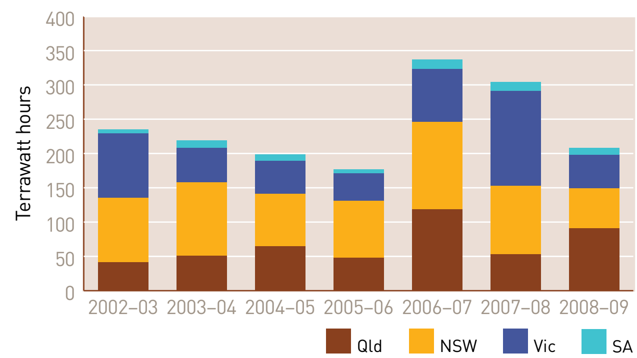
Data on liquidity in the OTC markets are limited because transactions are visible only to the parties engaged in trade. The Australian Financial Markets Association (AFMA) conducts an annual survey of OTC market participants on direct bilateral and broker assisted trade. It reports that most, but not all, participants respond to the survey. The AFMA data will capture a particular OTC transaction if at least one party to the trade participates in the survey.

As figure 3.8 indicates, total OTC trades declined from around 235 TWh in 2002–03 to around 177 TWh in 2005–06. This trend was reversed in 2006–07, with turnover increasing by more than 90 per cent to around 337 TWh. Volumes remained above 300 TWh in 2007–08 but fell significantly to around 208 TWh in 2008–09.

On a regional basis, trading volumes rose by more than 70 per cent in 2008–09 in Queensland, accounting for around 44 per cent of trade across all regions (up from around 17 per cent in 2007–08). Turnover remained steady in South Australia, but fell by 65 per cent in Victoria and 40 per cent in New South Wales.

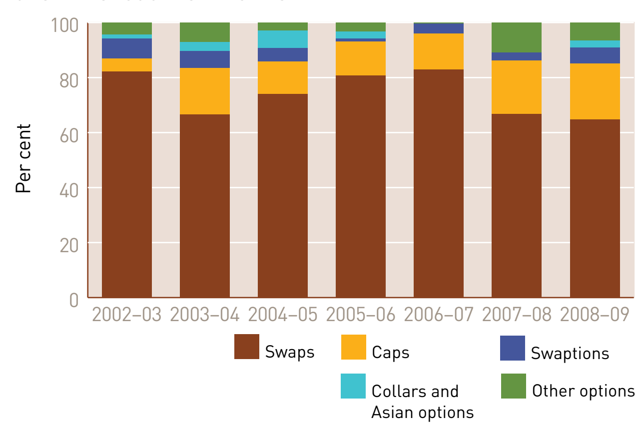
As in 2007–08 the bulk of OTC trade in 2008–09 was in swaps (around 65 per cent) and caps (around 20 per cent). Swaptions and other forms of options made up the balance (figure 3.9).

Figure 3.8
Regional trading volumes—over-the-counter market



Source: AFMA, *2009 Australian financial markets report*, Sydney, 2009.

Figure 3.9
Trading volumes, by derivative type—over-the-counter market



Source: AFMA, *2009 Australian financial markets report*, Sydney, 2009.

3.4.3 Aggregate trading volumes

Table 3.3 aggregates volumes of electricity derivatives traded in OTC markets and on the SFE, and compares these volumes with underlying demand for electricity in the NEM. The data are a simple aggregation of AFMA data on OTC volumes and d-cyphaTrade data on exchange trades. The results must be interpreted with some caution, given the AFMA data are based on a voluntary survey and are not subject to independent verification, and thus could omit transactions between survey non-participants (although AFMA considers the survey captures most OTC activity).

Derivative trading volumes can exceed 100 per cent of NEM demand, because some financial market participants take positions independent of physical market volumes and regularly re-adjust their contracted positions over time.

Table 3.3 Volumes traded in over-the-counter markets and the Sydney Futures Exchange

	OTC (TWH)	OTC (% OF NEM DEMAND)	SFE (TWH)	SFE (% OF NEM DEMAND)	TOTAL (% OF NEM DEMAND)
2001–02	168	96	0	0	96
2002–03	235	131	7	4	135
2003–04	219	118	29	16	134
2004–05	199	106	24	13	118
2005–06	177	92	55	28	120
2006–07	337	174	243	124	298
2007–08	304	156	241	123	279
2008–09	208	105	301	153	258

NEM, National Electricity Market; OTC, over-the-counter; SFE, Sydney Futures Exchange; TWh, terawatt hours.

Note: NEM demand excludes Tasmania, for which derivative products were not available.

Sources: AEMO; AFMA; d-cyphaTrade.

Based on the available data, the volume of financial trading in the SFE in 2008–09 exceeded volumes in the OTC market for the first time. The share of derivative trading in OTC markets declined from 97 per cent in 2001–02 to just 41 per cent in 2008–09. As table 3.3 indicates, OTC trades in 2008–09 were equivalent to 105 per cent of NEM demand, compared with a record 174 per cent in 2006–07. Volumes on the SFE rose from near zero in 2001–02 to levels equivalent to over 150 per cent of NEM demand in 2008–09. Across the combined OTC and exchange markets, trading volumes in 2008–09 were almost 260 per cent of NEM demand, down from almost 300 per cent in 2006–07 but still well above volumes in the preceding years.

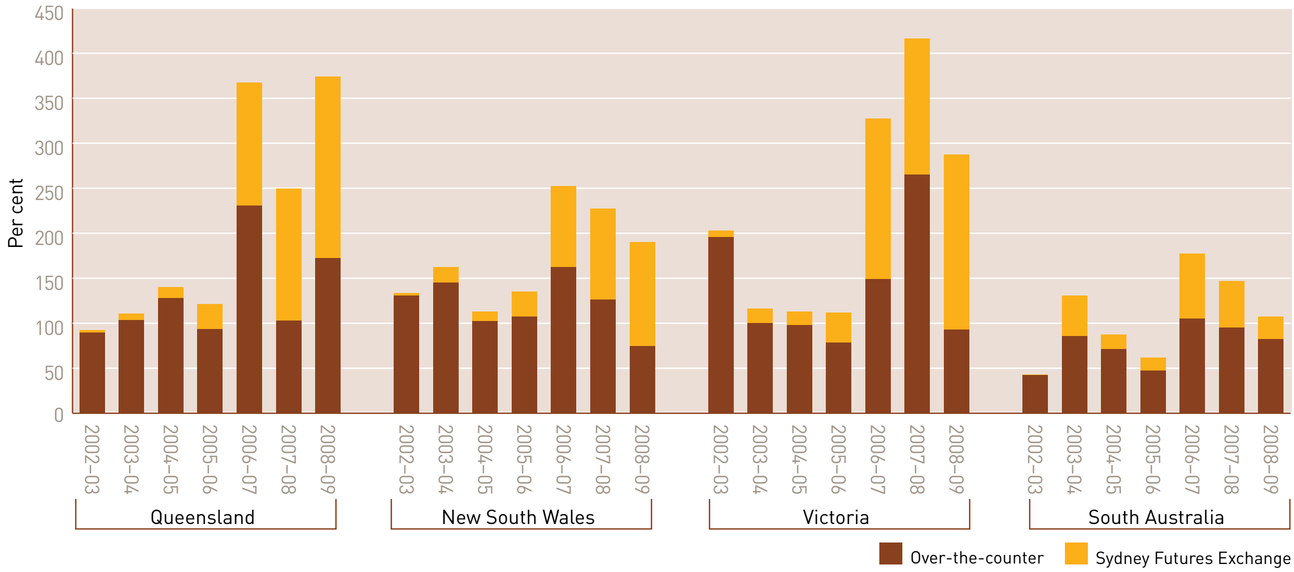
There are a number of reasons for the relatively strong growth in exchange traded volumes. Amendments to the Corporations Act and the introduction of international hedge accounting standards to strengthen disclosure obligations for electricity derivatives contracts might have raised confidence in exchange based trading. In addition, d-cyphaTrade, in conjunction with the SFE, redesigned the product offerings in 2002 to tailor them more closely to market requirements. These changes have encouraged greater depth in the market, including the entry of financial intermediaries.

The increase in trading volumes on the SFE has also been driven by some trading parties seeking to minimise mark-to-market OTC credit exposures. This issue became more acute in the difficult economic conditions in 2008–09, where a perception of increased financial risk for energy market participants might have accelerated the shift from OTC to SFE trading.

Figure 3.10 charts regional trading volumes in both the OTC and SFE sectors as a percentage of regional NEM demand. Trading volumes were generally equivalent to around 100–150 per cent of regional NEM demand in Queensland, New South Wales and Victoria from 2002–03 to 2005–06. Volumes rose sharply in 2006–07 to 370 per cent of NEM demand in Queensland, 330 per cent in Victoria, 250 per cent in New South Wales and 180 per cent in South Australia. In 2008–09 only Queensland experienced growth in trading volumes relative to regional NEM demand, reaching a record for the region of almost 375 per cent. Volumes in other regions were below levels for the past two years.

Figure 3.10

Regional trading volumes as a percentage of regional National Electricity Market demand



OTC, over-the-counter; SFE, Sydney Futures Exchange.

Sources: AEMO; AFMA; d-cyphaTrade.

The SFE trading volumes in 2008–09 exceeded OTC volumes in all regions except South Australia—the first time this has occurred in Victoria and New South Wales. Victoria's SFE trades accounted for over two thirds of regional trading volumes. In Queensland and New South Wales, SFE trade accounted for around 54 per cent and 61 per cent of trading volumes respectively. In South Australia, SFE trade fell from a high of 41 per cent in 2006–07 to 23 per cent in 2008–09.

A PricewaterhouseCoopers survey of market participants in 2006 raised possible reasons for poor liquidity in South Australia's financial markets. Reasons cited included the relatively small scale of the South Australian electricity market; perceptions of risk associated with network interconnection, generation capacity and extreme weather; and perceptions of high levels of vertical integration.[11]

3.5 Price transparency and bid–ask spread

While trading volumes and open interest indicate market depth, part of the cost to market participants of transacting is reflected in the bid–ask spread (the difference between the best buy and best sell prices) quoted by market makers and brokers. A liquid market is characterised by relatively low price spreads that allow parties to transact at a nominal cost.

d-cyphaTrade and other market data providers publish bid–ask spreads for the exchange traded market. In 2008–09 most spreads for base futures products were less than $3. Spreads are generally higher in the market for peak futures, which tends to be less liquid.

3.6 Number of market participants

Ownership consolidation, such as vertical integration across the generation and retailer sectors, can affect participation in financial markets. Vertical integration can reduce a company's activity in financial markets by increasing its internal capacity offset risk.

11 PricewaterhouseCoopers, *Independent survey of contract market liquidity in the National Electricity Market*, Sydney, 2006, p. 28.

The three largest private energy retailers—Origin Energy, AGL Energy and TRUenergy—are moving towards portfolios more balanced between generation and retail assets. In 2007 AGL Energy acquired the 1260 MW Torrens Island power station in South Australia from TRUenergy, in exchange for the Hallett power station (150 MW) and a cash sum. Origin Energy is quickly expanding its generation portfolio, commissioning the Uranquinty power station (650 MW) and expanding its Quarantine plant (130 MW) in 2008–09. It has also committed to a further 1250 MW of gas fired generation in Queensland and Victoria. All three businesses also have ownership interests in Australian wind farms. In addition, major generator International Power operates a retail business in Victoria and South Australia (trading as Simply Energy) and has achieved significant market penetration.

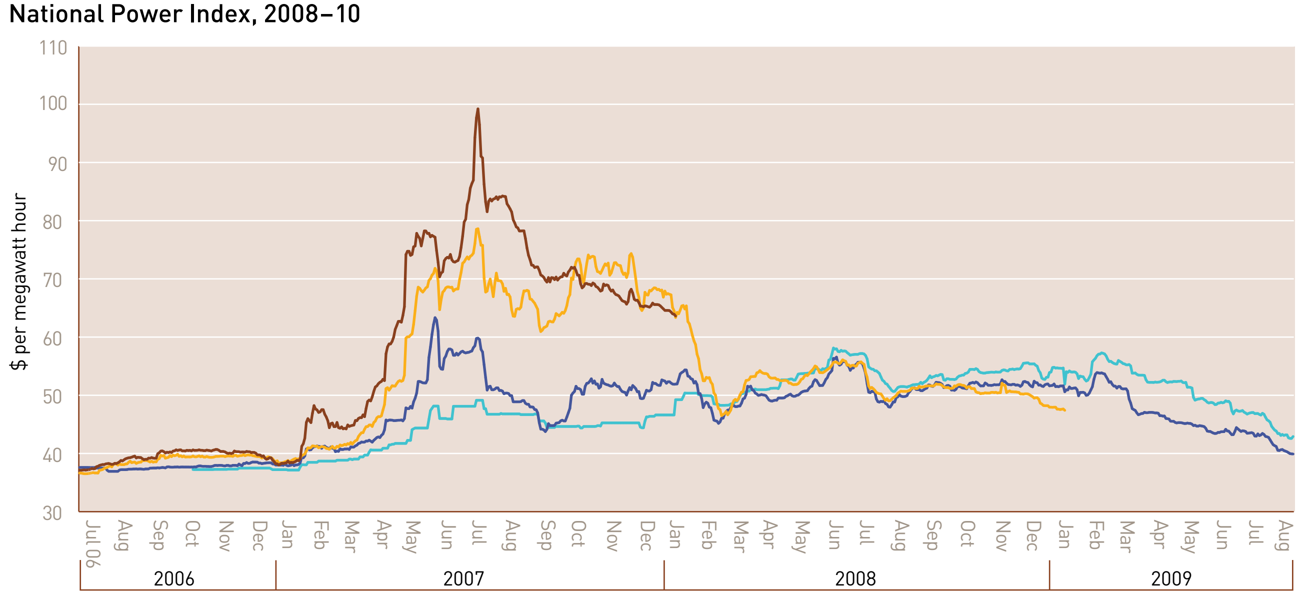
While integration might have reduced the number of generators and retailers in Australia's financial markets, new entry by financial intermediaries continues to add depth to the market.

3.7 Price outcomes

Base futures account for most SFE trading volumes and open interest positions. Accordingly, the following discussion of price outcomes focuses on base futures. Prices for peak futures tend to be higher than for base futures, but follow broadly similar trends.[12]

Figure 3.11 shows average price outcomes for electricity base futures, as reflected in the National Power Index (NPI). The index is published by d-cyphaTrade for each calendar year and represents a basket of the electricity base futures listed on the SFE for New South Wales, Victoria, Queensland and South Australia. It is calculated as the average daily settlement price of base futures contracts across the four regions for the four quarters of the relevant calendar year. The NPI data are available from June 2006 and are published daily. d-cyphaTrade also publishes a Eastern Power Index that excludes South Australian futures.

Figure 3.11
National Power Index, 2008–10



Source: d-cyphaTrade.

12 Base futures cover 0.00 to 24.00 hours, seven days per week. Peak futures cover 7.00 am to 10.00 pm Monday to Friday, excluding public holidays.

Figure 3.11 shows base futures prices were fairly flat throughout 2006, trading between $35 and $40 per MWh, before rising sharply in the first half of 2007. Prices for the 2007 calendar year basket peaked in June 2007 at close to $100 per MWh. This peak mirrored high prices in the physical electricity market, caused by tight supply–demand conditions (see section 2.5). Futures prices also rose sharply for the 2008 calendar year, but less so for later years (reflecting expectations that the tight supply–demand conditions at that time would be relatively short term).

A return to more benign conditions in the physical electricity market led to an easing of 2007 and 2008 base futures prices in the summer of 2007–08. Prices converged at around $50–55 per MWh over 2008. Prices fell further over the first half of 2009, to less than $45 per MWh for 2009 calendar year base futures. For the 2010 calendar year, base futures were trading at around a $5 premium over the 2009 product. But following the announcement in May 2009 of a delay in the introduction of the CPRS from 2010 to 2011, the premium for 2010 contracts fell from a high of around $6–7 per MWh to $2–3 per MWh at June 2009.

In general, contract markets often trade at a premium to the physical spot market for an underlying commodity. On average, base futures prices on the SFE traded at a fairly constant premium over NEM spot prices of around $2 per MWh over the past four years.[13]

3.7.1 Future forward prices

Figure 3.12 provides a snapshot in June 2009 of forward prices for quarterly base futures on the SFE for quarters up to two years from the trading date. These forward prices are often described as forward curves. The first four quarters of a forward curve are the prompt quarters. For comparative purposes, forward prices in June 2008 are also provided.

In June 2009 prices were generally down on the levels of 2008. This might have reflected lower demand projections for the coming year (particularly for summer) and the commissioning in 2008–09 of almost 2500 MW of new generation capacity. South Australia was the exception, with generally higher futures prices in 2009 than in 2008. This may indicate market concerns that high prices in South Australia's physical electricity market over the past two summers—as a result of high temperatures, interconnector constraints and opportunistic bidding by generators—may recur.

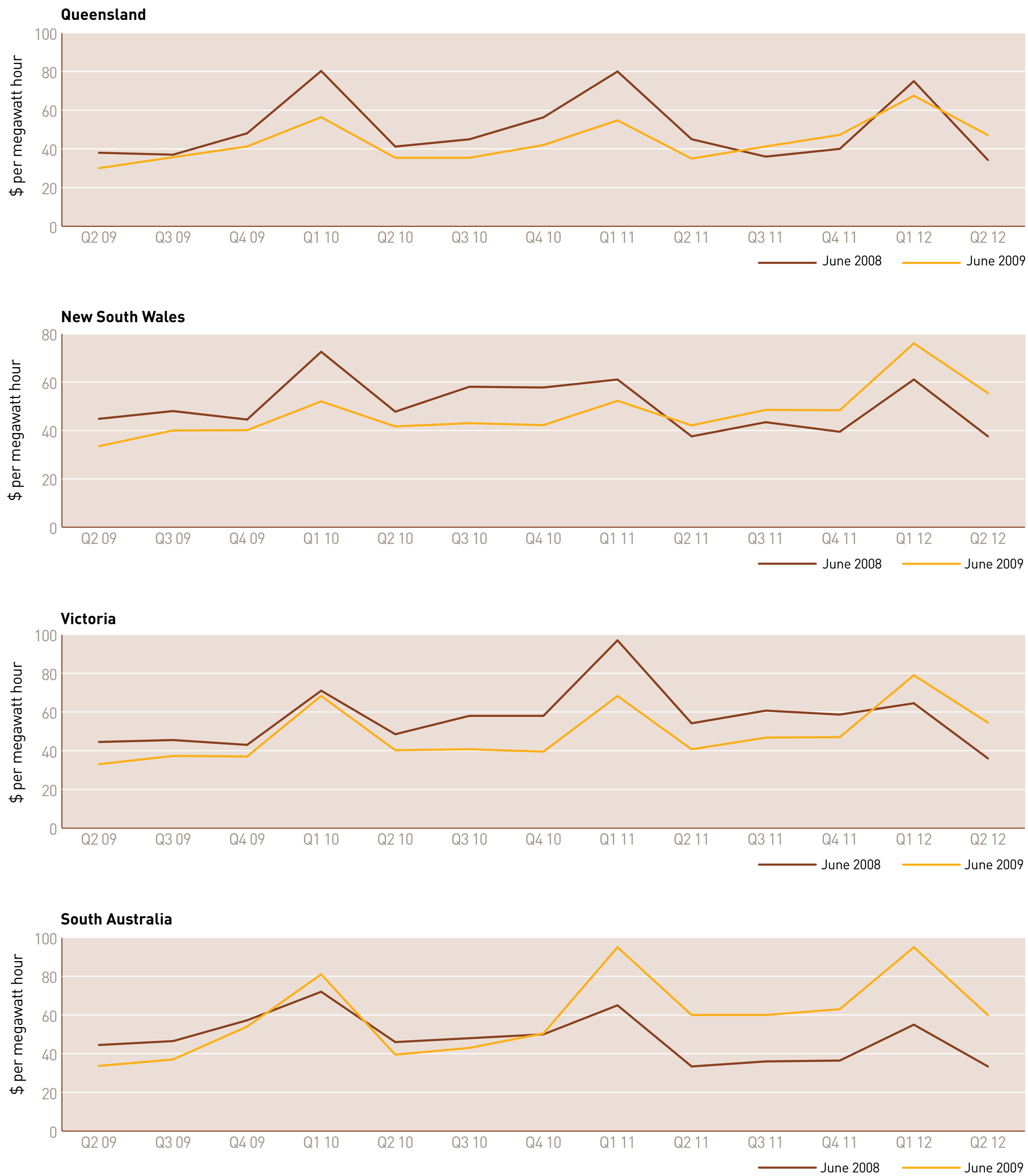
Figure 3.12 also illustrates that futures prices tend to be higher for the first quarter (Q1, January–March) than for other quarters. This reflects the tendency for NEM spot prices to peak in summer—when hot days lead to high demand for air conditioning, tightening the electricity supply–demand balance—and illustrates the links between derivative prices and underlying NEM wholesale prices.

The introduction of the CPRS is expected to put upward pressure on wholesale prices, as evident in rising forward prices from the third quarter of 2011 (relative to the same quarters in the previous year). For most regions, an initial price shift of around $5–6 per MWh was evident for the third and fourth quarters of 2011, rising to $10–14 in 2012. In Victoria, there is a larger increase in prices for the first quarter of 2012, perhaps reflecting concerns that the supply–demand balance in the electricity market may be tight at that time unless planned new capacity such as Origin Energy's 518 MW plant at Mortlake are operational. Poor liquidity in South Australian futures products makes it difficult to assess market expectations for that region.

While futures contracts typically relate to a specific quarter of a year, contracts are increasingly being traded as calendar year strips, comprising a 'bundle' of the four quarters of the year. This tendency is more pronounced for contracts with a starting date at least one year from the trade date. Figure 3.13 charts prices in June 2009 for calendar year futures strips to 2012. In June 2009 all regions had forward curves in strong contango—that is, prices are higher for contracts in the later years.

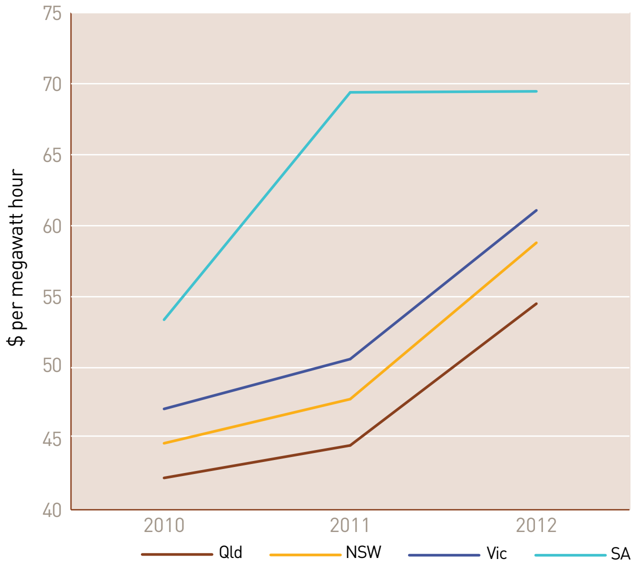
13 Based on a comparison of time weighted calendar year wholesale market spot prices to the average NPI value for each calendar year.

Figure 3.12
Base futures prices, June 2008 and 2009



Source: d-cyphaTrade.

Figure 3.13
Base calendar strip at June 2009



Source: d-cyphaTrade.

This is indicative of market expectations that price risk may be greater in the medium to longer term, and is consistent with an expectation that the CPRS may increase pool prices from 2011. The market may also be factoring in assessments of supply adequacy in some regions. South Australian prices are considerably above those for other regions, perhaps reflecting ongoing concerns about price risk in the wholesale market.

3.8 Price risk management—other mechanisms

Aside from financial contracts, other mechanisms can manage price risk in electricity wholesale markets. As noted, some retailers and generators have reduced their exposure to NEM spot prices through vertical integration. In addition:

> In New South Wales, the Electricity Tariff Equalisation Fund (ETEF) provides a buffer against prices spikes in the NEM for government owned retailers that are required to sell electricity to end users at regulated prices. When spot prices are higher than the energy component of regulated retail prices, ETEF pays retailers from the fund. Conversely, retailers pay into ETEF when spot prices are below the regulated tariff. The New South Wales Government has announced it will phase out ETEF over 2010–11.

> Auctions of settlement residues allow for some financial risk management in interregional trade, although the effectiveness of this instrument has been debated (see section 5.7).

4 BEYOND THE NATIONAL ELECTRICITY MARKET

Gillianne Tedder (Photolibrary.com)

Western Australia and the Northern Territory have electricity markets that are not interconnected with the National Electricity Market. Western Australia introduced a new wholesale electricity market in 2006. The Northern Territory has no wholesale market competition.

4 BEYOND THE NATIONAL ELECTRICITY MARKET

4.1 Western Australia's electricity system

Reflecting Western Australia's geography, industry and demographics, the state has several distinct electricity infrastructure systems (figure 4.1). The South West Interconnected System (SWIS) supplies 840 000 retail customers in the south west, including Perth. It has 5134 megawatts (MW) of installed generation capacity, 6000 kilometres of transmission lines and 85 000 kilometres of distribution lines. Western Australia introduced a wholesale electricity market in the SWIS in September 2006 (see section 4.5).

The North West Interconnected System (NWIS) operates in the north west of the state and centres on the industrial towns of Karratha and Port Hedland, and resource centres. It has a generation capacity of about 400 MW, mainly fuelled by natural gas. Given its small scale, the NWIS has no foreseeable plans to adopt a wholesale market in the manner of the SWIS.

In addition, 29 non-interconnected distribution systems operate around towns in rural and remote areas beyond the SWIS and NWIS networks.

4.2 Electricity reform in Western Australia

In 1993, when Australian governments decided to create a national electricity market, it was considered impractical for Western Australia to join. Geography dictated that the state's networks could not physically interconnect with the other jurisdictions.

Consistent with the eastern and southern states, Western Australia's electricity industry was historically dominated by a single, vertically integrated utility under government ownership. Western Australia retained this structure for almost a decade longer than other jurisdictions did. The lack of competition, combined with relatively high generation costs (due to relatively expensive coal sources and the remoteness of major gas fields), led to high wholesale electricity prices.

From 2003 the Western Australian Government launched a series of reforms. The central reform, undertaken in 2006, was the disaggregation of the state electricity utility into four separate entities:

- Verve Energy—generation
- Western Power—transmission and distribution networks
- Synergy—retail
- Horizon Power—integrated supply in regional areas.

The government also:

- established a wholesale electricity market in 2006 (see section 4.5)
- established an Electricity Networks Access Code in 2004 for access to transmission and distribution networks (see section 4.6)
- extended the retail contestability threshold in 2005 to all customers using more than 50 megawatt hours (MWh) per year (see section 4.7)

4.3 Western Australia's electricity market structure

Western Australia's electricity market retains a relatively concentrated ownership structure, with state owned utilities being prominent across the supply chain. In the SWIS—the principal electricity system—the state owned Western Power owns the bulk of transmission and distribution systems. Another state owned utility—Verve Energy—owns about two thirds of generation capacity. The balance is privately owned and mainly dedicated to resource projects.

The introduction of a wholesale market in 2006 led to new generator entry and greater ownership depth. Verve Energy's share of installed generation capacity will fall from around 77 per cent in 2007–08 to 60 per cent in 2010–11.[1] In particular, three new participants—NewGen Power, Griffin Power and Alcoa—have acquired (or will acquire) significant capacity. Table 4.1 illustrates the extent of new entry since 2006. Table 4.2 summarises recent investment activity.

Despite new entry, all but one of the new generation plants scheduled by 2010–11 has been contracted to the state owned retailer, Synergy.[2] The absence of full retail competition in Western Australia means Synergy supplies all retail customers in the SWIS (including small business and residential consumers) using up to 50 MWh of electricity per year. The Economic Regulation Authority (ERA) considers the absence of a clear timetable for full retail contestability may deter new entry in retail and generation.[3]

The Office of Energy commenced a review in 2008 of the costs and benefits of introducing full retail contestability, but at 1 July 2009 had not made any recommendations. The ERA has described the current arrangements in generation and retail as leading to a 'quasi bilateral monopoly market structure'.[4]

The Western Australian Government expects further new entry and the phasing out of vesting contracts to reduce the market share of state owned corporations over time.[5] In addition, the government:

- has placed a 3000 MW cap on Verve Energy's ability to invest in new generation plant, to allow independent generators to increase their market share over time
- restricted Synergy from generating electricity, and Verve Energy from retailing electricity, until at least 2013.

1 ERA (Western Australia), *Annual wholesale electricity market report for the Minister for Energy*, Perth, 2008, p. vii.

2 ERA (Western Australia), *Annual wholesale electricity market report for the Minister for Energy*, Perth, 2008, p. 45.

3 ERA (Western Australia), 'Energy market reform in WA—a progress report', Presentation by Lyndon Rowe to the WA Power & Gas 2009 Conference, Perth, 17 and 18 February 2009, p. 4.

4 ERA (Western Australia), 'Energy market reform in WA—a progress report', Presentation by Lyndon Rowe to the WA Power & Gas 2009 Conference, Perth, 17 and 18 February 2009, p. 4.

5 The vesting contracts relate to the wholesale supply of electricity by Verve Energy to Synergy in the SWIS. The arrangements were intended as a transitional measure to ensure Synergy could meet the sales obligations it inherited in 2006 from former integrated utility Western Power.

Figure 4.1

Electricity infrastructure map—Western Australia

Source: ERA (Western Australia).

Table 4.1 **Participants in Western Australia's wholesale electricity market**

PARTICIPANT	GENERATORS		CUSTOMERS	
	2006	2009	2006	2009
Alcoa	■	■	■	■
Alinta Sales Pty Ltd	■	■	■	■
Barrick (Kanowna) Limited			■	■
Bioenergy Limited		■		
Clear Energy Pty Ltd				■
Coolimba Power Pty Ltd		■		
EDWF Manager Pty Ltd	■	■		
Eneabba Gas Limited		■		
Enebba Energy Pty Ltd		■		
Energy Response Pty Ltd				■
Goldfields Power Pty Ltd	■	■		
Griffin Power Pty Ltd		■		■
Griffin Power 2 Pty Ltd		■		■
Karara Energy Pty Ltd				■
Landfill Gas and Power Pty Ltd	■	■	■	■
Mount Herron Engineering Pty Ltd	■	■		
Namarkkon Pty Ltd		■		
NewGen Neerabup Pty Ltd		■		
NewGen Power Kwinana Pty Ltd		■		
Newmont Power Pty Ltd			■	■
Perth Energy Pty Ltd	■	■	■	■
Premier Power Sales Pty Ltd			■	■
SkyFarming Pty Ltd		■		
South West Cogeneration Joint Venture		■		
Southern Cross Energy	■	■	■	■
Synergy			■	■
Transalta Energy (Australia)				■
Transfield Services Kemerton Pty Ltd		■		
Verve Energy	■	■	■	■
Walkaway Wind Power Pty Ltd		■		
Waste Gas Resources Pty Ltd	■	■		
Water Corporation			■	■
Worsley Alumina		■		

Source: ERA (Western Australia).

Table 4.2 **Investment in the South West Interconnected System from 2006**

PARTICIPANT	INVESTMENT
Alinta Sales	280 MW OCGT power station at Pinjarra (acquired by BBP August 2007) 380 MW OCGT power station at Wagerup (acquired by BBP August 2007)
Stanwell/Griffin	80 MW wind farm at Emu Downs opened October 2006
Griffin Energy	200 MW Bluewaters 1 coal fired plant commissioned in 2009 200 MW Bluewaters 2 coal fired plant under construction for end 2009 330 MW North Peak gas fired plant near Neerabup proposed for 2010-11
NewGen Power Kwinana	320 MW Kwinana combined cycle gas plant opened November 2008
Western Australian Biomass	40 MW boiler/steam turbine power station fired by biomass to begin operation in 2009-10
Eneabba Gas	168 MW Centauri 1 gas fired plant near Eneabba scheduled to begin operation in 2009
Western Energy	80 MW Kwinana combined cycle gas fired plant due 2010
Aviva	400 MW Coolimba coal fired plant near Eneabba due 2012
ATCO Power	86 MW Karratha gas fired plant under construction for 2010
Western Power	$3.5 billion on network improvements from 2008, including: > 330 kV transmission line from Pinjar to Moonyoonooka > 330 kV transmission line from Collie to Perth's eastern suburbs > new transmission capacity, including new substations at Wangara, Joondalup, Warwick and Thornlie > expansion of distribution network's capacity

BBP, Babcock & Brown Power; kV, kilovolt; OCGT, open cycle gas turbine.

Principal sources: IMO (Western Australia), Office of Energy (Western Australia).

In 2008 a possible merger between Verve Energy and Synergy was considered. The Western Australian Government decided in August 2009 not to proceed with the merger.[6]

In regional Western Australia, Horizon Power is a vertically integrated utility responsible for the generation (or its procurement), transmission, distribution and retailing of electricity to customers in the NWIS and in 29 smaller non-interconnected systems. Horizon Power buys power from a number of private generators in the Pilbara, including Hamersley Iron's 120 MW generation plant at Dampier, Robe River's 105 MW plant at Cape Lambert and Babcock & Brown Power's 175 MW plant at Port Hedland.

4.4 Electricity generation in Western Australia

Statewide, around 60 per cent of installed generation capacity is fuelled by natural gas and 35 per cent by coal (figure 4.2). Gas is used in base load cogeneration plants and peaking units. Generation from renewable sources has grown, with wind accounting for around 63 per cent, and hydro and biomass comprising most of the balance. Renewable sources fuelled about 3.8 per cent of statewide generation in 2007–08. In the SWIS, generation from renewables increased sevenfold between 2003 and 2008, and now supplies around 5 per cent of electricity demand.[7]

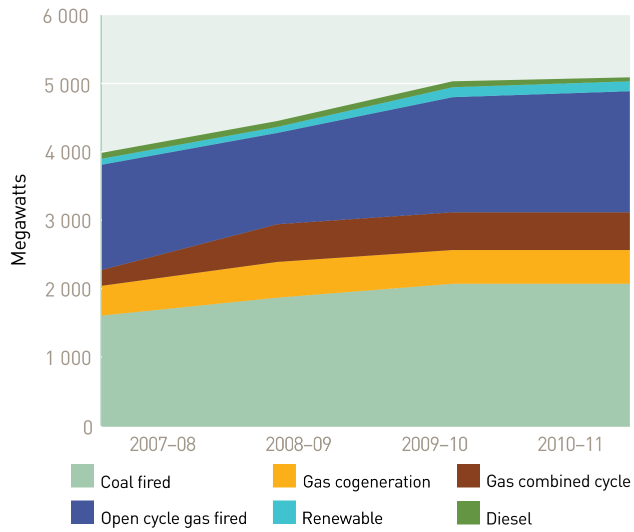
The Western Australian Government has set a target of 6 per cent of electricity to be sourced from renewable energy by 2010. The biomass plant scheduled for commissioning in December 2009 is expected to lift the share of renewable energy production above this target.

6 Peter Collier (Minister for Energy, Western Australia), 'State's energy future outlined', Media release, 26 August 2009.

7 Sustainable Energy Development Office (Western Australia), *Renewable energy*, fact sheet, Perth, 2008.

Figure 4.2

Installed generation capacity—Western Australia's south west



Note: Data are for the South West Interconnected System, covering Perth and other major centres in the south west of the state.

Source: IMO (Western Australia).

4.5 Western Australia's wholesale electricity market

In September 2006 Western Australia launched a wholesale electricity market in the SWIS. A combination of bilateral contracts, a day-ahead short term energy market (STEM) and a balancing market facilitate energy trading. The market was designed to suit Western Australian conditions and differs considerably from the National Electricity Market (NEM) (see chapter 2):

> The Independent Market Operator (IMO), a government entity established in 2004, is the rule development body and market operator.[8] It has no commercial interest in the market and no connection with any market participant.

> The physical system operator, System Management, is a ring-fenced entity within Western Power that is tasked with maintaining the safe, secure and reliable operation of the power system. It is responsible for the operation and control of generators, transmission and distribution networks, and large customer retailer supply management.

4.5.1 Market design

Figure 4.3 illustrates the key elements of Western Australia's wholesale market in the SWIS.

The following are the three main areas of difference between the market design for the SWIS and the NEM in eastern and southern Australia:

> gross pool versus net pool

> capacity market arrangements

> ancillary services.

Gross pool versus net pool

The NEM is a gross pool in which the sale of all wholesale electricity occurs in a spot market. NEM participants also enter formal hedge contracts to manage spot market risk. In contrast, energy in the SWIS is traded mainly through bilateral contracts outside the pool. These contracts may be entered into years, weeks or days before supply. Before the trading day, generators must inform the IMO of the quantity of energy to be sold under bilateral contracts, and to whom it will be sold, to enable the IMO to schedule that supply.

In the lead-up to dispatch, System Management issues instructions to ensure supply equals demand in real time. Dispatch, rather than being on a least cost basis, reflects mainly the contract positions of participants. Generators submit daily resource plans that inform the IMO of how their facilities will be used to meet their contract positions. They are obliged to follow these plans, unless dispatch instructions replace the plans. Verve Energy's facilities are scheduled around the resource plans of other generators. If it appears supply will not equal demand, the IMO will schedule Verve Energy generation first, then issue dispatch instructions to other market participants as necessary.

Beyond bilateral contracts, a day-ahead STEM and a balancing market are used to trade wholesale electricity (figure 4.3). The STEM supports bilateral trades by allowing market participants to trade around their contract positions a day before energy is delivered. If, for example, a generator does not have sufficient

8 Information on the market can be found on the IMO website (www.imowa.com.au).

capacity to meet its contracted position, then it can bid to purchase energy in the STEM. Participating generators must offer generation plant at short run marginal cost. Each morning, market participants may submit to the IMO bids to purchase energy and/or offers to supply energy.[9] The IMO then runs an auction, in which it takes a neutral position to determine a single price for each trading interval of the day.

A market participant's actual supply or consumption of electricity during a trading interval may deviate from its net contract position (the sum of its bilateral position and STEM trades), given unexpected deviations in demand and unplanned plant outages. The shortfall or surplus is traded on the balancing market. The IMO calculates balancing prices, which for Verve Energy plant are generally equal to the short run marginal cost of the last unit dispatched. Any independent power producer plant dispatched for balancing or ancillary service provision is 'paid as bid'.

Capacity market

The SWIS market includes both an energy market (the STEM) and a capacity market (figure 4.3). The capacity market is intended to provide incentives for investment in generation to meet peak demand. In particular, it is intended to provide sufficient revenue for investment without the market experiencing high and volatile energy prices. The IMO administers a reserve capacity mechanism to ensure there is adequate installed capacity to meet demand. It determines how much capacity is required to meet peak demand each year, and allocates the costs of obtaining the necessary capacity to buyers (mostly retailers).

Generators are assigned capacity credits, which entitle them to payments for offering their capacity to the market at all times. The IMO assigns credits to generators that intend to trade their capacity bilaterally. If insufficient reserves are obtained through this process, the IMO runs an auction to allocate the additional capacity credits.

The market made monthly payments of $10 625 per MW of capacity from market start to 1 October 2008. For the 12 months from 1 October 2008, generators received a monthly payment of $8152 per MW of capacity. This amount rose to $9038 per MW of capacity for the 12 months from 1 October 2009.[10] The payments are intended to cover the fixed costs of an open cycle peaking gas turbine and to partly cover the capital costs of base load units.

The NEM has no capacity market. Instead, generators are paid only for energy sent out, and a high price cap provides incentives to invest in generation and establish demand-side responses. The provision of capacity payments means spot energy prices in Western Australia are unlikely to peak as high as NEM prices to stimulate investment.

There are two energy price limits in the STEM: a maximum price for supply other than that from plant running on liquid fuel; and an alternative maximum STEM price (AMSP) based on supply from all facilities. The maximum price is based on the marginal cost of an open cycle gas turbine using natural gas as fuel. It is adjusted annually. For the year to 1 October 2008, the cap was $206 per MWh. For the year to 1 October 2009, the cap was $286 per MWh. In comparison, the NEM operates with a price cap of $10 000 per MWh. The AMSP is adjusted monthly based on movements in the Singapore Crude Oil price. It peaked in September 2008 at $779 per MWh.

9 To receive reserve capacity payments, generators must offer all registered capacity to the STEM.

10 Information on capacity credits can be found on the IMO website (www.imowa.com.au).

Figure 4.3

Western Australia's wholesale electricity market

ENERGY MARKET

BILATERAL CONTRACTS

- These contracts cover about 95% of electricity sold by volume.
- Generators and energy consumers contract directly.
- Quantities are submitted to the IMO between one and eight days before each trading day.
- The IMO has no knowledge of price.

SHORT TERM ENERGY MARKET (STEM)

- The STEM covers 0–4% of electricity sold by volume.
- This day-ahead short term market allows changes in market position.
- The IMO clears offers to sell against bids to buy.
- The IMO establishes a STEM price and quantity cleared for each half hour.
- The STEM is a transparent market.

BALANCING MARKET

- This market covers 2–6% of electricity sold by volume.
- It is a market for deviations of actual volumes from bilateral and STEM positions.
- The price is generally equal to the STEM price.
- The IMO calculates balancing prices and settles trades.

CAPACITY MARKET

- Generators are assigned capacity credits entitling them to payments for offering capacity into the market at all times.
- This market is intended to provide incentives for investment to meet peak demand.
- It is administered by the IMO.

Western Power

Source: IMO (Western Australia).

The IMO determines annual reserve capacity requirements and releases an annual statement of opportunities report covering 10 years. The ERA must approve the IMO's proposed maximum reserve capacity price and energy price caps in the short term market.

Figure 4.4 summarises the demand and capacity outlook for 2010–11 at 2008. The IMO has set a reserve capacity target for 2010–11 of 5146 MW. To meet this target, 226 MW of new generation and demand-side management capacity will be required beyond that already in place or under construction.[11]

Ancillary services

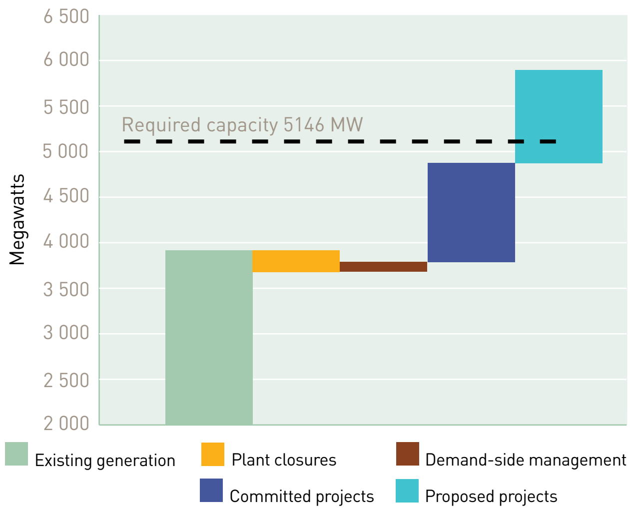
The NEM has eight frequency control ancillary services spot markets in which participants may bid to provide services. Network control ancillary services are procured through long term contracts. In contrast, the SWIS has no spot markets for ancillary services; rather, System Management determines ancillary services requirements and procures them from Verve Energy or other participants under contract arrangements.

11 IMO (Western Australia), *State of opportunities*, Perth, 2008, p. 4.


Western Power

Figure 4.4

Western Australia's demand and capacity outlook for 2010–11, at 2008



Source: IMO (Western Australia).

4.5.2 Market outcomes

While it is too early to assess the outcomes of the Western Australian energy market, developments can be observed. The number of market participants is increasing, with new retailers and generators entering the market. Table 4.2 shows there has been strong interest in investment in the energy market, including in renewable energy. There is evidence of more varied plant sizes, technologies and fuel types, as well as cost-efficient plant upgrades. The ERA stated, however, that resourcing constraints within Western Power are delaying some generation investment.[12]

Another outcome has been the introduction of more cost-reflective prices in the STEM, which reflect the cost of energy during system peaks and short term pressures such as fuel shortages and strong demand. There is less cost reflectivity in the retail market, however, where gazetted tariffs have applied for several years.[13]

Trading activity in the STEM and balancing market typically ranged from about 4 per cent to 6 per cent of total sales in the first year of the market's operation (2006–07). More recently, STEM trades have risen, largely between generators seeking access to lower cost plant. In 2008–09 the volume of energy traded in the STEM and balancing market ranged from about 6 per cent to 14 per cent of total sales (figure 4.5).

On most days, the number of market participants placing STEM bids fluctuates between four and seven. While Verve Energy accounts for a majority of capacity in the market, other participants have also been active. In contrast, the level of competition in the bilateral contract market is difficult to gauge because such contracts are confidential.

The ERA stated it is not aware of outcomes in the STEM that indicate market power is an issue. It has raised concerns, however, about:

- the appropriateness of the investment signals provided by the market
- the appropriateness of the timing of the reserve capacity mechanism and whether this can create barriers to investment for facilities with long lead times
- whether the timing of planned network outages has an impact on the effectiveness of the market
- whether there are barriers to the participation of consumers in demand-side management programs.[14]

Price outcomes

Price outcomes in the STEM and balancing markets provide transparent price signals on the cost of electricity. The mean peak STEM price from market start to 31 July 2008 was \$80.20 per MWh, while the mean off-peak price was \$38.10 per MWh.[15]

12 ERA (Western Australia), *Annual wholesale electricity market report for the Minister for Energy*, Perth, 2008, p. viii.

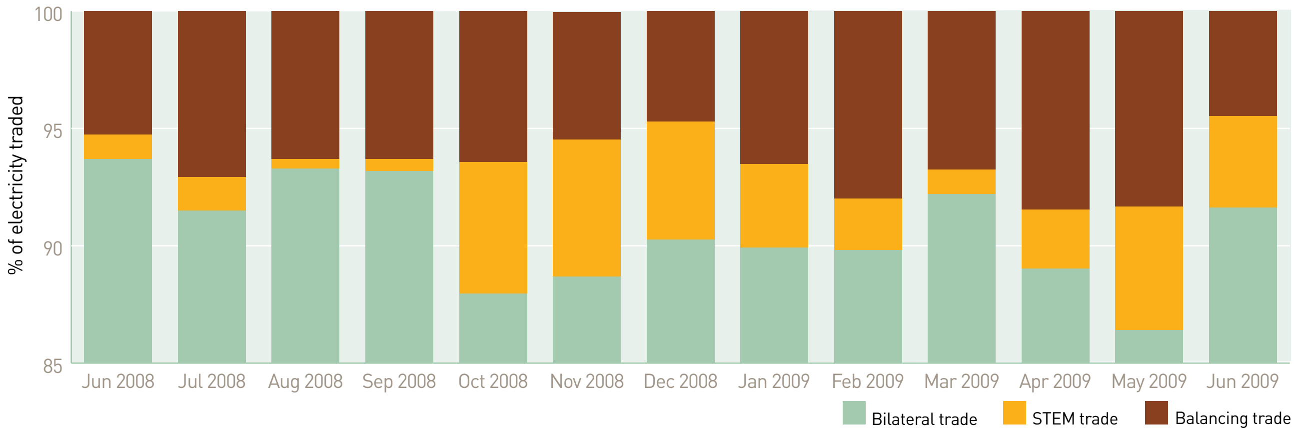
13 See section 4.7.

14 ERA (Western Australia), *Annual wholesale electricity market report for the Minister for Energy*, Perth, 2007, p. viii.

15 ERA (Western Australia), *Annual wholesale electricity market report for the Minister for Energy*, Perth, 2008, p. 10.

Figure 4.5

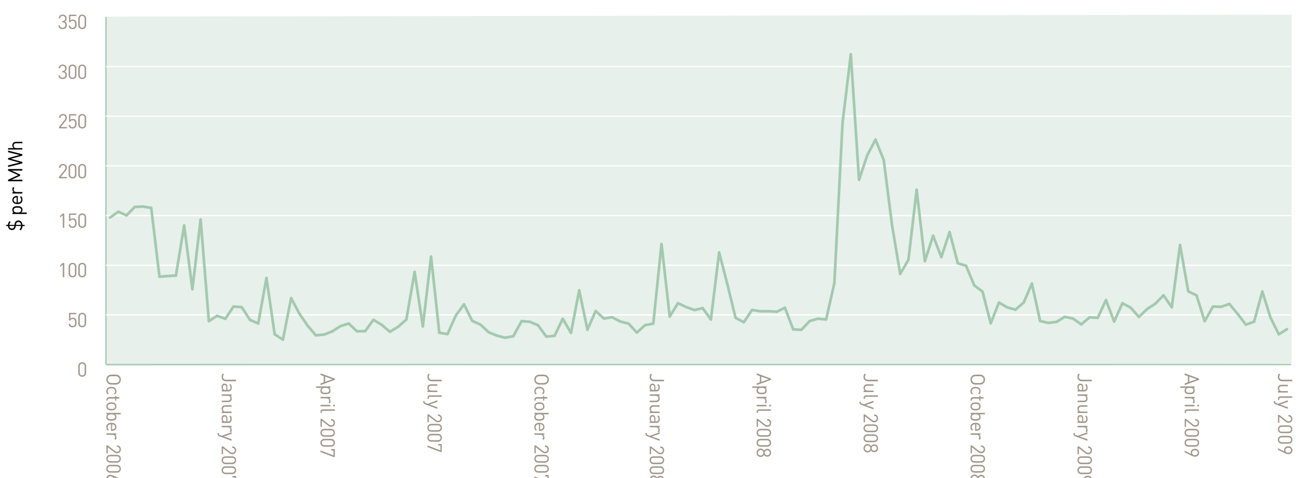
Composition of electricity trading in the Western Australian market



Source: IMO (Western Australia).

Figure 4.6

Weighted average weekly prices—Western Australia's short term energy market



Source: IMO (Western Australia).

Figure 4.6 shows the weighted average weekly STEM prices from market start to June 2009. The early high prices were due to fuel restrictions and low generator availability. Prices then followed a fairly regular seasonal pattern—with summer and winter peaks—until May 2008. In June 2008 gas shortages caused by an explosion at the Varanus Island plant led to soaring gas prices. Given natural gas fuels a majority of Western Australia's generation plant, this flowed through to record wholesale electricity prices. Average daily prices peaked on 26 June 2008 at $429 per MWh.[16] Prices eased in late 2008 as the gas constraints were addressed, but remained above historical seasonal levels in early 2009.

16 ERA (Western Australia), *Annual wholesale electricity market report for the Minister for Energy*, Perth, 2008, p. 11.

4.6 Network access in Western Australia

In 2004 Western Australia implemented the Electricity Networks Access Code for access to transmission and distribution network services. The code covers only Western Power's networks within the SWIS, but other networks may be covered in the future if they meet the access regime's coverage tests. In July 2006 the Australian Government certified the code as an effective access regime under the *Trade Practices Act 1974*.

The ERA administers the code, which prescribes commercial arrangements, including access charges that electricity generators and retailers must pay to use Western Power's networks. The regulatory framework sets out criteria for the ERA's acceptance or rejection of an access arrangement that the service provider proposes.

The ERA in 2007 approved Western Power's first access arrangement under the code, covering the three year period from 2006–07. In July 2009 it released a draft decision on Western Power's access arrangement for the three year period from 2009–10.

Chapters 5 and 6 of this report include some data on the Western Power networks, including performance outcomes.

4.7 Retail arrangements in Western Australia

In January 2005 Western Australia extended retail contestability to electricity customers using at least 50 MWh per year. In the SWIS, all customers using less than 50 MWh per year are served by Synergy, the state owned energy retailer. Horizon Power serves most customers outside the SWIS. In 2008 the state's Office of Energy commenced a review of the costs and benefits of introducing full retail contestability, but it had not released its findings as of 1 July 2009.

Regulated retail tariffs in the SWIS are set at levels that are well below costs. In January 2009 the Office of Energy recommended residential tariffs increase by 52 per cent in 2009–10 and a further 26 per cent in 2010–11, to reflect substantial increases in the cost of supplying electricity.[17] In February 2009 the Western Australian Government rejected these recommendations and announced domestic electricity charges would rise by 10 per cent on 1 April 2009, followed by a rise of 15 per cent in July 2009.[18] The ERA noted that retailers will not be able to compete with Synergy for those customers that have the option of remaining on below-cost regulated tariffs. It considers this outcome is likely to preserve a concentrated retail sector.[19]

Chapter 7 of this report further details Western Australia's electricity retail market.

4.8 The Northern Territory's electricity industry

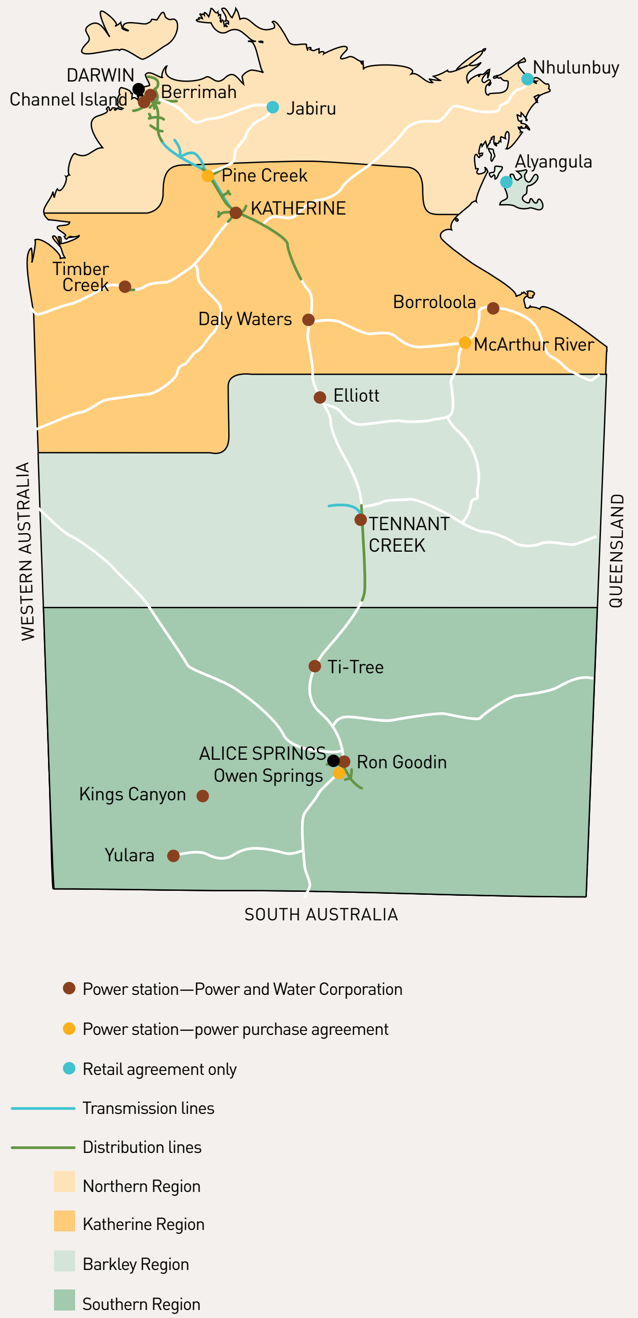
The Northern Territory's electricity industry is small, reflecting its population of around 220 000, of whom only around 82 500 are connected to a network. There are three relatively small regulated systems,[20] of which the largest is the Darwin–Katherine system, with a capacity of around 320 MW (figure 4.7). The total capacity of the Territory's regulated systems was 444 MW at 30 June 2008, after the commissioning of the first generator at the Weddell Power Station. In 2007–08 the Territory consumed around 1795 gigawatt hours of electricity.

The Territory uses gas fired plant to generate public electricity, sourcing gas from the Amadeus Basin in Central Australia. The Amadeus fields cannot sustain increasing demand, however, and many contracts for gas supply are due to end in 2009. In some cases, diesel has been used at considerable cost to meet gas supply shortfalls.

17 Office of Energy (Western Australia), Electricity Retail Market Review, *Final recommendations report—review of electricity tariff arrangements*, Perth, 2009, p. 2.
18 Peter Collier (Minister for Energy, Western Australia), 'State Government announces increases in tariff arrangements', Media release, 23 February 2009.
19 ERA (Western Australia), 'Energy market reform in WA—a progress report', Presentation by Lyndon Rowe to the WA Power & Gas 2009 Conference, Perth, 17 and 18 February 2009, p. 3.
20 The Darwin–Katherine, Alice Springs and Tennant Creek systems.

Figure 4.7

Northern Territory electricity system



Source: Power and Water Corporation.

A new source of gas supply from late 2009 will be the Blacktip Field in the Joseph Bonaparte Gulf. The gas will come onshore to a processing plant near Wadeye, then will be transported by the Bonaparte Gas Pipeline (which connects to the existing Amadeus Basin-to-Darwin Pipeline). Delays in the construction of the processing plant postponed the first supply of gas from the Blacktip Field, which was scheduled for 1 January 2009. Once the processing plant is complete, this arrangement is expected to meet the Territory's gas demand for the next 25 years.[21]

4.8.1 Market arrangements

Given the scale of the Northern Territory market, a wholesale electricity spot market was not considered feasible. Rather, the Territory uses a 'bilateral contracting' system whereby generators are responsible for dispatching the power that their customers require.

The industry is dominated by a government owned corporation, Power and Water, which owns the transmission and distribution networks. Power and Water is also the monopoly retail provider and generator. In addition, it is responsible for power system control. Six independent power producers in the resource and processing sector generate their own requirements and also generate electricity under contract with Power and Water.

From around 2000 the Northern Territory Government introduced measures to open the electricity market to competition:

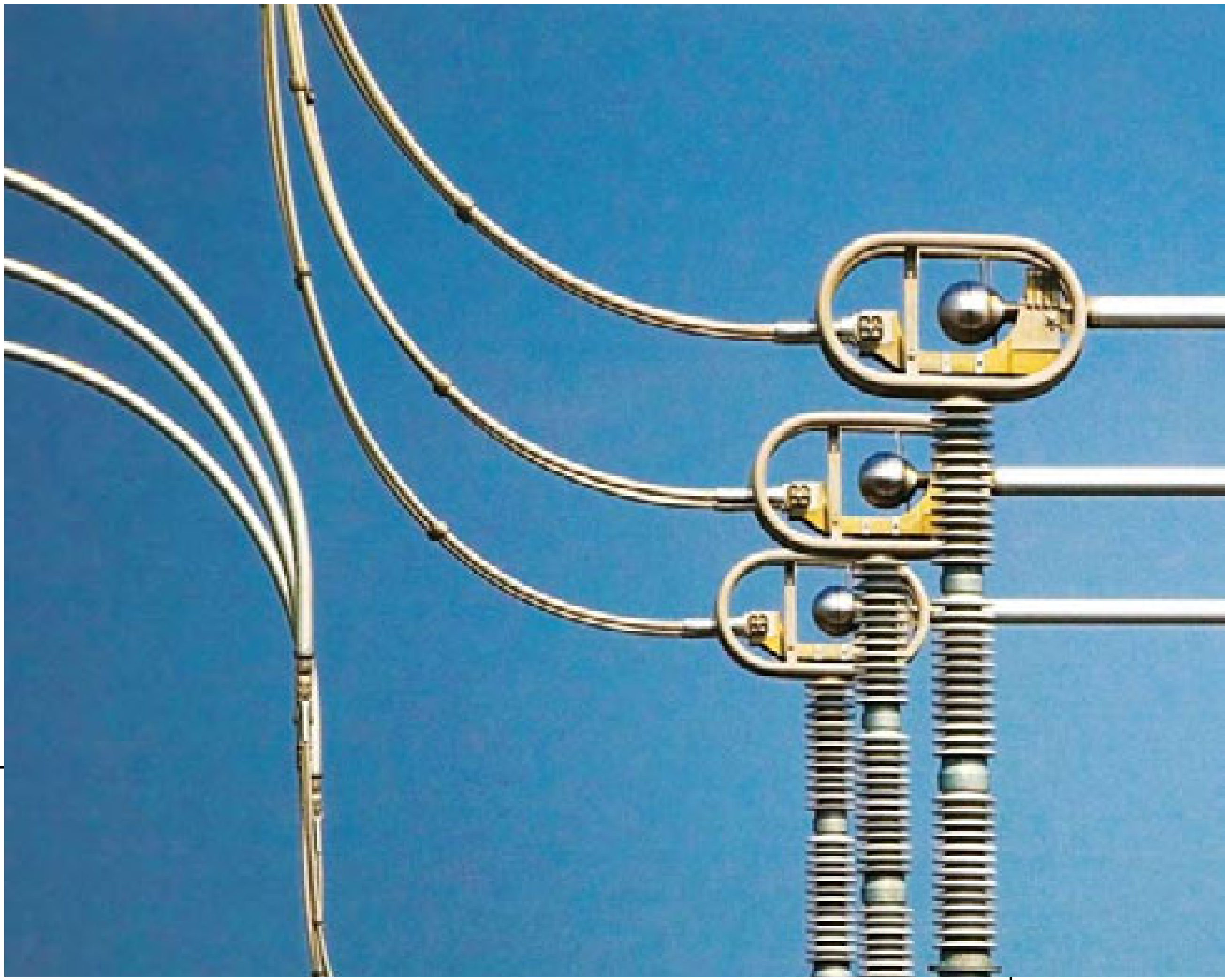
- It commenced a phased introduction of retail contestability, scheduled for completion by April 2005 but later rescheduled for April 2010 (see below).
- It corporatised the vertically integrated electricity supplier (Power and Water) and ring-fenced its generation, power system control, network and retail activities.
- It allowed new suppliers to enter the market.
- It established an independent regulator, the Utilities Commission, to regulate monopoly services and monitor the market.
- It introduced a regulated access regime for transmission and distribution services. In 2002 the Australian Government certified the regime as effective under the Trade Practices Act. In March 2009 the Utilities Commission made its third five year determination on network access arrangements (for 2009–10 to 2013–14).

There has been one new entrant in generation and retail since the reforms: NT Power, which acquired some market share. It withdrew from the market in September 2002, however, citing its inability to source ongoing gas supplies for electricity generation. In light of this withdrawal, the Northern Territory Government suspended the contestability timetable in January 2003, effectively halting contestability at the 750 MW per year threshold until prospects for competition re-emerge. A single subsequent applicant was not granted an electricity retail licence due to the applicant's 'inability to meet reasonably foreseeable obligations for the sale of electricity'.[22] The introduction of full retail contestability is scheduled for April 2010.

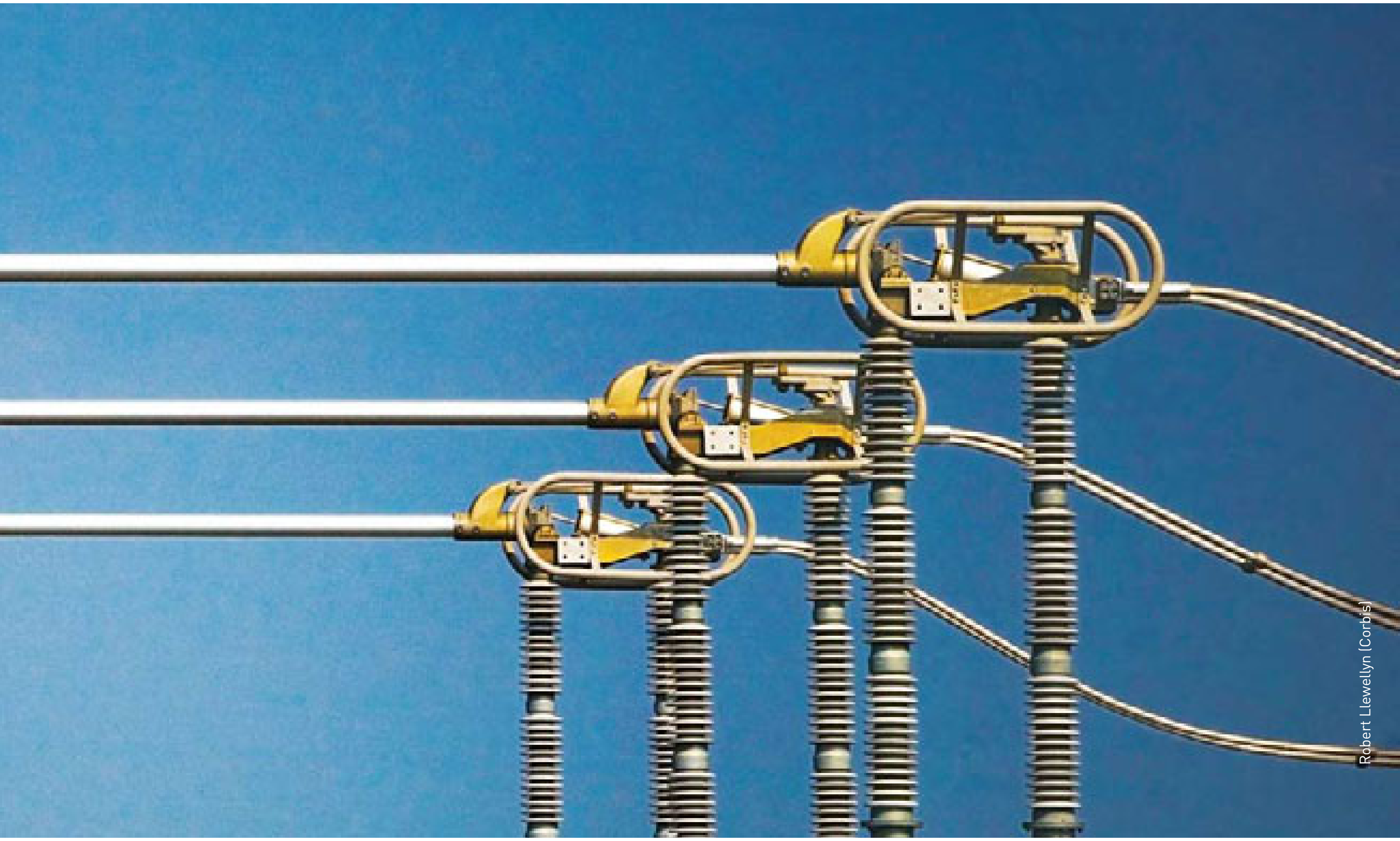
When Power and Water reverted to a retail monopoly, the government approved prices oversight by the Utilities Commission of Power and Water's generation business for as long as the business is not subject to a tangible threat of competition. The government regulates tariffs for non-contestable customers via electricity pricing orders. The Utilities Commission regulates service standards, including standards for reliability and customer service.

21 Power and Water Corporation, *Annual report 2008*, Darwin, 2008, p. 18.

22 Department of Business, Economic and Regional Development (Northern Territory Government), *The NT electricity, water and gas supply sector,* fact sheet, Darwin, 2005.



5 ELECTRICITY TRANSMISSION


Robert Llewellyn (Corbis)

Electricity generators are usually located close to fuel sources such as natural gas pipelines, coal mines and hydroelectric water reservoirs. Most electricity customers, however, are located a long distance from these generators in cities, towns and regional communities. The electricity supply chain, therefore, requires networks to transport power from generators to customers. The networks also enhance the reliability of electricity supply by allowing a diverse range of generators to supply electricity to end markets. In effect, the networks provide a mix of capacity that can be drawn on to help manage the risk of a power system failure.

5 ELECTRICITY TRANSMISSION

This chapter considers:

> the role of the electricity transmission network sector
> the structure of the sector, including industry participants and ownership changes over time
> the economic regulation of the transmission network sector by the Australian Energy Regulator
> revenues and rates of return in the transmission network sector
> new investment in transmission networks
> the operating and maintenance costs of running transmission networks
> quality of service, including transmission reliability and the market impacts of congestion.

Some of the matters canvassed in this chapter are addressed in more detail in the Australian Energy Regulator's annual report on the transmission sector.[1]

5.1 Role of electricity transmission networks

Transmission networks transport electricity from generators to distribution networks, which in turn transport electricity to customers. In a few cases, large businesses such as aluminium smelters are directly connected to the transmission network. A transmission network consists of towers and the wires that run between them, underground cables, transformers, switching equipment, reactive power devices, and monitoring and telecommunications equipment.

1 AER, *Transmission network service providers: electricity performance report for 2007–08*, Melbourne, 2009.

Electricity must be converted to high voltages for efficient transport over long distances. This minimises the loss of electrical energy that naturally occurs.[2] In Australia, transmission networks consist of equipment that transmits electricity at or above 220 kilovolts (kV), along with assets that operate at 66–220 kV that are parallel to, and provide support to, the higher voltage transmission network.

The high voltage transmission network strengthens the performance of the electricity industry in three ways:

> First, it gives customers access to large, efficient generators that may be located hundreds of kilometres away. Without transmission infrastructure, customers would have to rely on generators in their local area, which may be more expensive than remote generators.
> Second, allowing many generators to compete in the electricity market helps reduce the risk of market power.
> Third, allowing electricity to move instantaneously over long distances reduces the amount of spare generation capacity that must be provided at each town or city to ensure a reliable electrical supply. This reduces inefficient investment in generation.

5.2 Australia's electricity transmission networks

In Australia, there are transmission networks in each state and territory, with cross-border interconnectors that link some networks. The National Electricity Market (NEM) in eastern and southern Australia provides a fully interconnected transmission network from Queensland through to New South Wales, the Australian Capital Territory (ACT), Victoria, South Australia and Tasmania (figure 5.1). The transmission networks in Western Australia and the Northern Territory do not interconnect with the NEM or each other (see chapter 4).

The NEM transmission network is unique in the developed world in terms of its long distances, low density and long, thin structure. It reflects the often long distances between demand centres and fuel sources for generation. The 290 kilometre link between Victoria and Tasmania, for example, is one of the longest submarine power cable in the world. By contrast, transmission networks in the United States and many European countries tend to be meshed and of a higher density. These differences result in transmission charges being a more significant contributor to end prices in Australia than they are in many other countries —for example, transmission charges comprise about 10 per cent of retail prices in the NEM[3] compared with 4 per cent in the United Kingdom.[4]

Electricity can be transported over alternating current (AC) or direct current (DC) networks. Most of Australia's transmission network is AC, whereby the power flow over individual elements of the network cannot be directly controlled. Instead, electrical power (which is injected at one point and withdrawn at another) flows over all possible paths between the two points. As a result, decisions on how much electricity is produced or consumed at one point on the network can affect power flows in other parts of the network. Australia also has three DC networks, of which all are cross-border interconnectors.

5.2.1 Ownership

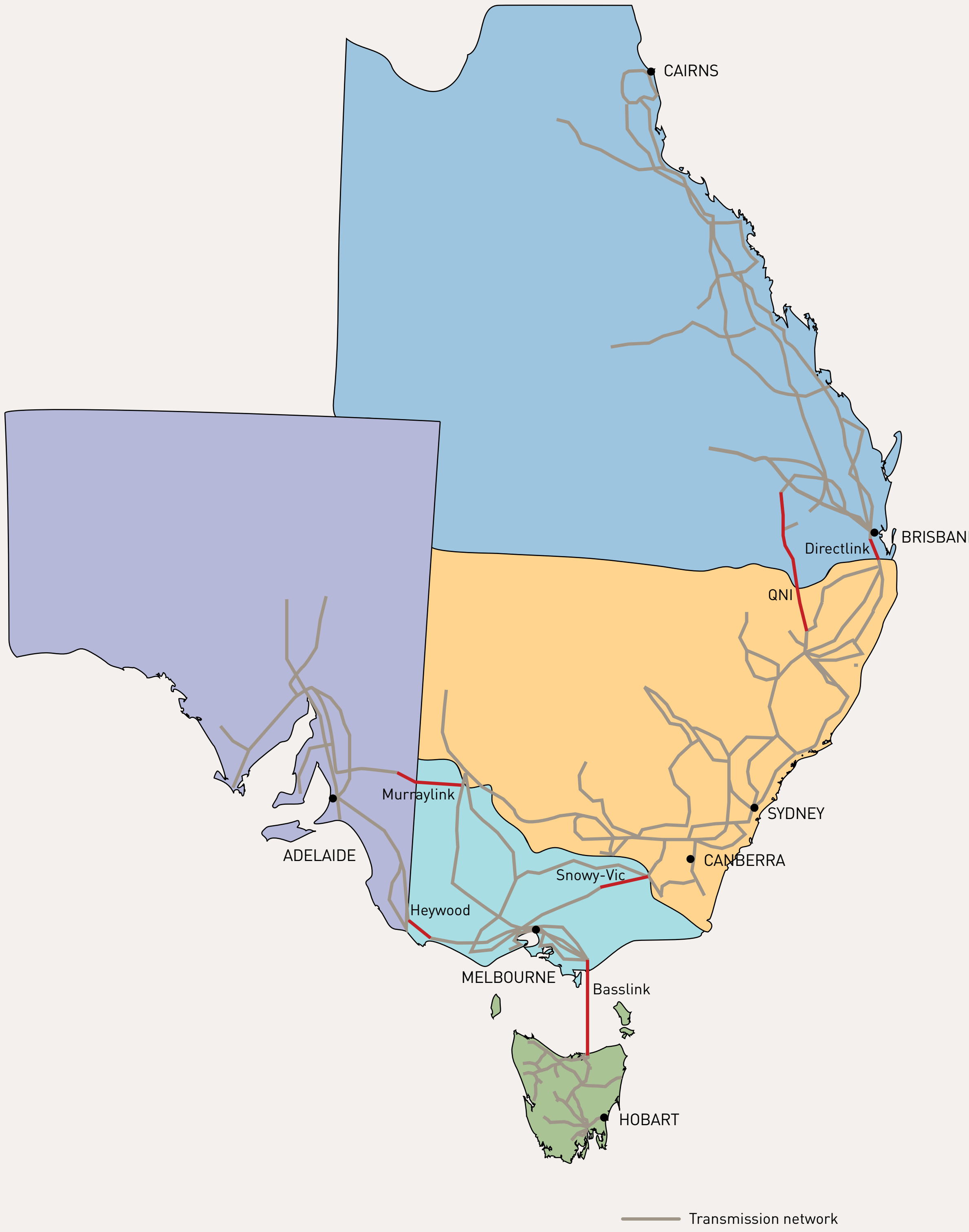
Table 5.1 lists Australia's transmission networks and their current ownership arrangements. Historically, government utilities ran the entire electricity supply chain in all states and territories. In the 1990s governments began to separate the generation, transmission, distribution and retail segments into stand-alone businesses. Generation and retail were opened up to competition, but this approach was not appropriate for the transmission and distribution networks, which became regulated monopolies.

2 While transportation of electricity over long distances is efficient at high voltages, there are risks, such as flashovers. A flashover is a brief (seconds or less) instance of conduction between an energised object and the ground (or another energised object). The conduction consists of a momentary flow of electricity between the objects, and is usually accompanied by a show of light and possibly a cracking or loud exploding noise. High towers, insulation and wide spacing between the conductors help to manage this risk.

3 The contribution of transmission to final retail prices varies across jurisdictions, customer types and locations.

4 Ofgem, *Factsheet 66*, London, January 2008 (available at www.ofgem.gov.uk).

Figure 5.1
Transmission networks in the National Electricity Market



QNI, Queensland – New South Wales Interconnector.

Table 5.1 Electricity transmission networks in Australia

NETWORK	LOCATION	LINE LENGTH (KM)	ELECTRICITY TRANSMITTED (GWh), 2007–08	MAXIMUM DEMAND (MW), 2007–08	ASSET BASE (2008 $ MILLION)[1]	INVESTMENT—CURRENT PERIOD (2008 $ MILLION)[2]	CURRENT REGULATORY PERIOD	OWNER
NEM REGION NETWORKS								
Powerlink	Qld	12 671	48 576	8 082	3 922	2 528	1 July 2007 – 30 June 2012	Queensland Government
TransGrid	NSW	12 486	76 359	12 954	4 064	2 405	1 July 2009 – 30 June 2014	New South Wales Government
EnergyAustralia[3]	NSW	885	32 007	5 683	1 013	1 182	1 July 2009 – 30 June 2014	New South Wales Government
SP AusNet	Vic	6 553	51 927	9 850	2 232	990[4]	1 Apr 2008 – 30 Mar 2014	Publicly listed company (Singapore Power International 51%)
ElectraNet	SA	5 620	13 734	3 172	1 284	650	1 July 2008 – 30 June 2013	Powerlink (Queensland Government), YTL Power Investment, Hastings Utilities Trust
Transend	Tas	3 650	11 298	2 332	936	606	1 July 2009 – 30 June 2014	Tasmanian Government
NEM total		41 865	233 901	42 073	13 451	8 292		
INTERCONNECTORS[5]								
Directlink	Qld–NSW	63		180	130		1 July 2005 – 30 June 2015	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Murraylink	Vic–SA	180		220	119		1 Oct 2003 – 30 June 2013	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Basslink	Vic–Tas	375			845[6]		Unregulated	Publicly listed CitySpring Infrastructure Trust (Temesek Holdings (Singapore) 28%)
NON-NEM REGION NETWORKS								
Western Power	WA	6 792	14 500	3 420	2135[7]	1528[7]	1 July 2009 – 30 June 2012[8]	Western Australian Government
Power and Water	NT	730					1 July 2009 – 30 June 2014	Northern Territory Government

1. The regulated asset bases are as set at the beginning of the current regulatory period for each network, converted to June 2008 dollars.
2. Investment data are forecast capital expenditure over the current regulatory period, converted to June 2008 dollars.
3. EnergyAustralia's transmission assets, at 1 July 2009, are treated as distribution assets for the purpose of economic regulation. Future performance of the network will be assessed under the framework applicable to distribution network service providers.
4. SP AusNet's investment data include forecast augmentation investment by AEMO (formerly VENCorp).
5. Not all interconnectors are listed. The unlisted interconnectors, which form part of the state based networks, are Heywood (Victoria – South Australia), QNI (Queensland – New South Wales), Snowy – New South Wales and Snowy–Victoria.
6. Given Basslink is not regulated, there is no regulated asset base. The asset value listed is the estimated construction cost.
7. Data from the ERA's draft decision on proposed revisions to Western Power's access arrangement for the period 2009–10 to 2011–12.
8. At July 2009 Western Power's access arrangement for the period 2009–10 to 2011–12 was not finalised.

Principal sources: AER, *Transmission network service providers: electricity performance report for 2007–08*, Melbourne, 2008, and previous years; AER/ACCC revenue cap decisions; ERA (Western Australia), *Draft decision on proposed revisions to the access arrangement for the South West Interconnected Network*, Perth, July 2009; company websites and media releases.

Figure 5.2
Electricity transmission network ownership

		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
QLD	Powerlink	Queensland Government															
NSW	TransGrid	New South Wales Government															
	Energy Australia	New South Wales Government															
VIC	SP AusNet	Powernet Victoria			GPU Powernet			SPI PowerNet (Singapore Power)					SP AusNet (51% Singapore Power)				
SA	ElectraNet	South Australian Government						Powerlink (Qld Government), YTL Power			Powerlink (Queensland Government), YTL Power, Hastings						
TAS	Transend	Tasmanian Government															
INTERCONNECTORS	Directlink							Hydro-Quebec Group, NorthPower						APA Group		APA, Marubeni, Osaka Gas	
	Murraylink									Hydro-Quebec Group, SNC-Lavalin				APA Group		APA, Marubeni, Osaka Gas	
	BassLink													NGT	CitySpring Infrastructure Trust		
WA	Powerlink	Western Australian Government															

NGT, National Grid Transco.

Note: Some corporate names have been abbreviated or shortened.

Figure 5.2 illustrates network ownership changes since 1994. Victoria and South Australia privatised their transmission networks, but other jurisdictions retained government ownership:

- Singapore Power International acquired Victoria's state transmission network in 2000 following the network's original sale to GPU Powernet in 1997. Singapore Power International floated SP AusNet in 2005, but retained a 51 per cent stake.
- South Australia sold the state transmission network (ElectraNet) in 2000 to a consortium of interests led by Powerlink, which the Queensland Government owns. YTL Power Investments, part of a Malaysian conglomerate, is a minority owner. Hastings Fund Management acquired a stake in ElectraNet in 2003.

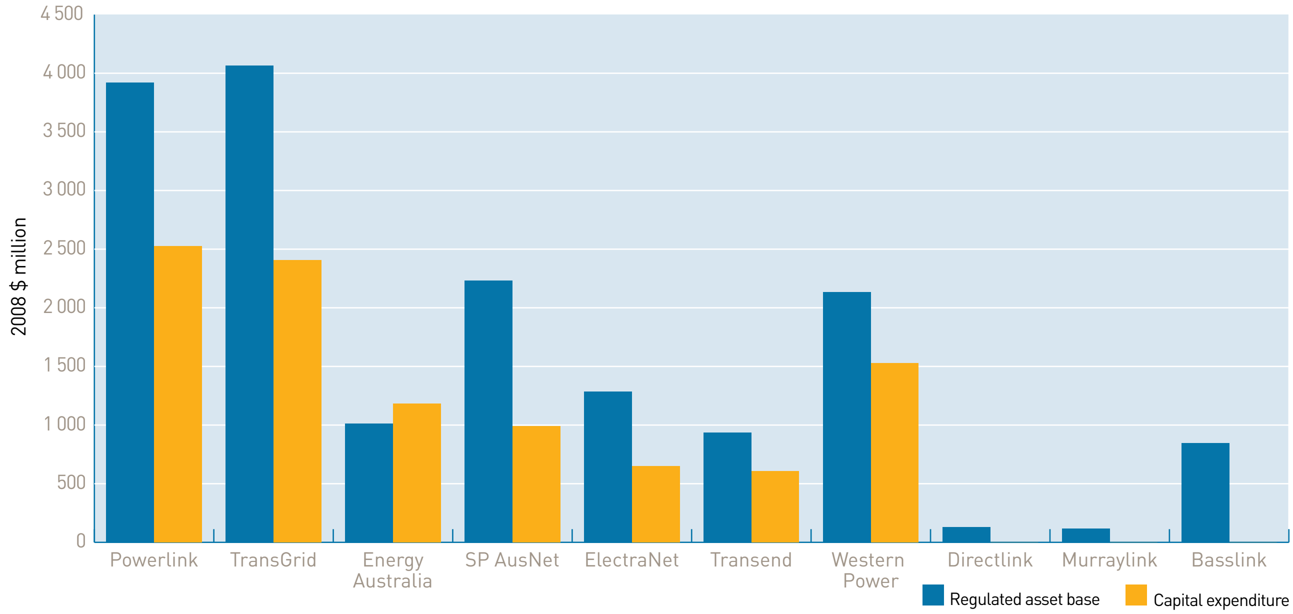
Victoria has a unique transmission network structure in which asset ownership is separated from planning and investment decision making. SP AusNet owns the state's transmission assets, but the Australian Energy Market Operator (AEMO, formerly VENCorp) plans and directs network augmentation. AEMO also buys bulk network services from SP AusNet for sale to customers.

Private investors have constructed three interconnectors —Murraylink, Directlink and Basslink—since the commencement of the NEM. All have since changed ownership. As of December 2008 Energy Infrastructure Investments has owned Murraylink and Directlink. The APA Group has a 20 per cent stake in the business and manages, maintains and operates the assets. A trust with links to Singapore Power International acquired Basslink in 2007.

5.2.2 Interconnection

Aside from the Snowy Mountains Hydro-Electric Scheme, which has supplied electricity to New South Wales and Victoria since 1959, transmission lines that cross state and territory boundaries are relatively new. In 1990, more than 30 years after the inception of the Snowy scheme, the Heywood interconnector between Victoria and South Australia commenced operation.

Figure 5.3
Electricity transmission network assets and investment



Notes:

Regulated asset bases are as at the beginning of the current regulatory period. The regulated asset base value for Basslink is the estimated construction cost.

Investment data are forecast capital expenditure for the current regulatory period (typically, five years). See table 5.1 for the timing of current regulatory periods.

EnergyAustralia's transmission assets, at 1 July 2009, are treated as distribution assets for the purpose of economic regulation.

SP AusNet includes augmentation investment by AEMO (formerly VENCorp).

Data for Western Power are from the ERA's draft decision on proposed revisions to Western Power's access arrangement for the period 2009–10 to 2011–12.

All values are converted to June 2008 dollars.

Sources: AER/ACCC revenue cap decisions; ERA (Western Australia), *Draft decision on proposed revisions to the access arrangement for the South West Interconnected Network*, Perth, July 2009.

The construction of new interconnectors gathered pace with the commencement of the NEM in 1998. Two interconnectors between Queensland and New South Wales (Directlink[5] and the Queensland – New South Wales Interconnector) commenced operation in 2000, followed by a second interconnector between Victoria and South Australia (Murraylink) in 2002. Murraylink is the world's longest underground power cable. The construction of a submarine transmission cable (Basslink) from Victoria to Tasmania in 2006 completed the interconnection of all transmission networks in eastern and southern Australia. Figure 5.1 shows the interconnectors in the NEM.

5.2.3 Scale of the networks

Figure 5.3 compares asset values and capital expenditure in the current regulatory period for the transmission networks. It reflects asset values as measured by the regulated asset base (RAB) for each network.

The RAB is the asset valuation that regulators use, in conjunction with rates of return, to set returns on capital to infrastructure owners. In general, it is set by estimating the replacement cost of an asset at the time it was first regulated, plus subsequent new investment, less depreciation. More generally, it indicates relative scale.

5 Directlink is also known as the Terranora interconnector.

Powerlink (Queensland) and TransGrid (New South Wales) have significantly higher RABs than those of other networks. Many factors can affect the size of the RAB, including the basis of original valuation, network investment, the age of a network, geographic scale, the distances required to transport electricity from generators to demand centres, population dispersion and forecast demand profiles. The combined RAB of all transmission networks is around $15.6 billion. This amount will continue to rise over time, with investment in the current regulatory periods forecast at almost $10 billion (see section 5.4).

5.3 Economic regulation of electricity transmission services

Electricity transmission networks are capital intensive and incur declining marginal costs as output increases. This gives rise to a natural monopoly industry structure. In Australia, the networks are regulated to manage the risk of monopoly pricing.[6] The Australian Competition and Consumer Commission (ACCC) was the industry regulator of transmission networks in the NEM until this role transferred to the Australian Energy Regulator (AER) in 2005. The Economic Regulation Authority and Utilities Commission are the regulators for the Western Australian and Northern Territory networks respectively.

5.3.1 Regulatory process

Chapter 6A of the National Electricity Rules (Electricity Rules) sets out the timelines and processes for the regulation of transmission businesses in the NEM. Regulated transmission businesses must periodically apply for the AER to assess their revenue (typically, every five years). These applications, or revenue proposals, must be consistent with the submission guidelines that the AER developed under the Electricity Rules.

The regulatory process usually commences with a transmission business submitting a revenue proposal to the AER. Once a proposal is submitted, the determination process takes 13 months, including time to consult with stakeholders. The transmission business must also submit a proposed pricing methodology and negotiating framework for approval by the AER. The pricing methodology is a formula or process for a business to allocate its revenue allowance and determine the structure of prices it may charge for its prescribed services. The negotiating framework details guidelines for the provision of services to third parties.

Within six months of a revenue proposal being lodged, the AER must release a draft determination. As part of the determination, the AER must decide whether a service target performance incentive scheme (service standards scheme) and/or efficiency benefit sharing scheme will apply to the transmission business. It must also approve or reject the pricing methodology and negotiating criteria.[7]

Once a draft determination is published, the transmission business may submit a revised revenue proposal within 30 business days. The AER must also hold a conference to allow stakeholders to comment on the draft determination. After the conference, stakeholders have a further 45 business days to make written submissions. The AER's final decision, which accounts for any revised proposal and stakeholder comments, is released at least two months before the new regulatory period begins.

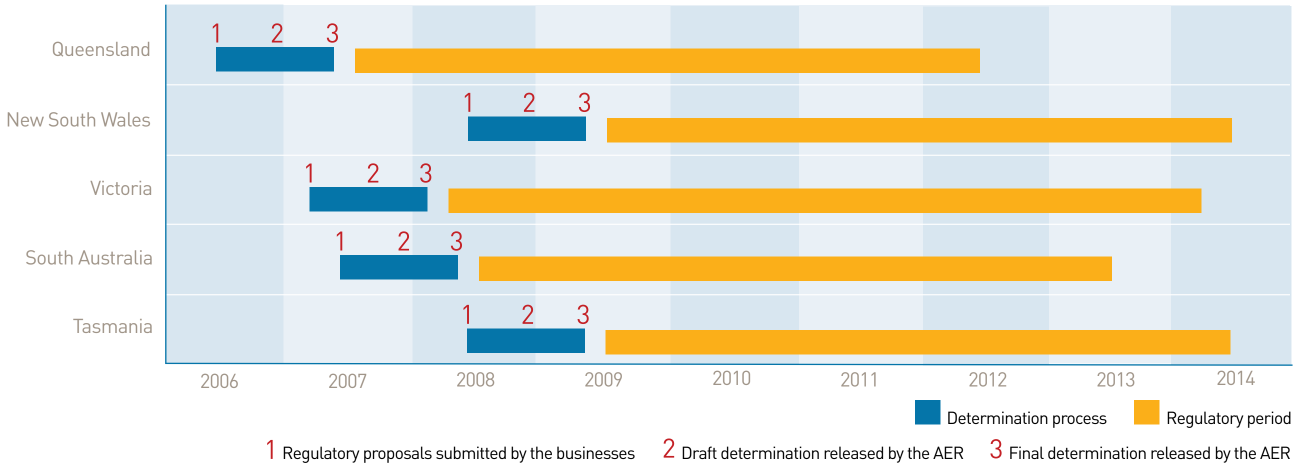
Figure 5.4 shows the regulatory timelines for each transmission network. The most recent determinations were for the New South Wales and Tasmanian networks (box 5.1)

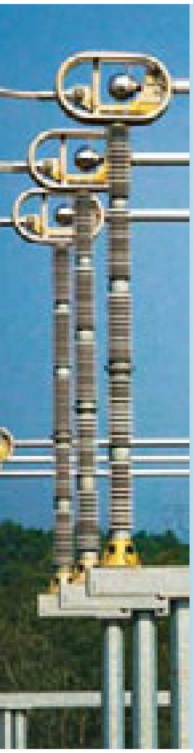
6 The Murraylink, Directlink and Basslink interconnectors were constructed as unregulated infrastructure that aimed to earn revenue through arbitrage. That is, they profited by purchasing electricity in low price NEM regions and selling it into higher price regions. Murraylink and Directlink converted to regulated networks in 2003 and 2006 respectively. Basslink is the only unregulated transmission network in the NEM.

7 If the AER does not accept the pricing method and negotiating framework proposed by the transmission business, it must detail how those documents can be changed to make them compliant with the Electricity Rules.

Figure 5.4

Determination process for electricity transmission networks





Box 5.1 New South Wales and Tasmanian transmission determinations

In April 2009 the AER released its revenue determination for TransGrid and EnergyAustralia[8] (the transmission service providers in New South Wales) and Transend (the provider in Tasmania). These determinations provide for $3.6 billion of capital expenditure for the New South Wales networks and $0.6 billion for the Tasmanian network between 2009–10 and 2013–14.

The determinations provide for a significant increase in investment—140 per cent higher than for the previous five years (in real terms)—and will allow the networks to comply with more stringent network performance, reliability and security requirements, replace aging assets and meet growing peak demand. Projects include constructing a 500 kV network around the Newcastle–Sydney–Wollongong area to meet future load growth, reinforcing the inner Sydney transmission system and constructing a Waddamana–Lindisfarne transmission line in Tasmania.

The AER also approved significant increases in operating and maintenance expenditure allowances.

The overall revenue allowance for the regulatory period is $3.6 billion for TransGrid and around $0.9 billion for EnergyAustralia and Transend. The decisions reflect revised economic forecasts (factoring in the effect of the global financial crisis) of weaker demand growth.

These revenue allowances will increase annual nominal transmission charges by about 4.8 per cent for TransGrid and 6 per cent for Transend.

Sources: AER, *TransGrid transmission determination 2009–10 to 2013–14, final decision*, Melbourne, April 2009; AER, *Transend transmission determination 2009–10 to 2013–14, final decision*, Melbourne, April 2009; AER, *New South Wales distribution determination 2009–10 to 2013–14, final decision*, Melbourne, April 2009.

8 EnergyAustralia's revenue allowance was set under the framework for distribution network businesses. See chapter 6 for more details of this process.

5.3.2 Regulatory approach

The AER's regulatory approach, as set out in the Electricity Rules, is to determine a revenue cap for each transmission business, setting the maximum revenue that a network can earn during a regulatory period (typically, five years). Unlike the distribution sector, all transmission businesses must be subject to a revenue cap (as opposed to other control mechanisms—for example, a price cap). In setting the revenue cap, the AER applies a building block model to determine the revenue that a transmission business needs to cover its efficient costs while providing for a commercial return to the business. The component building blocks cover:

- operating and maintenance expenditure
- capital expenditure
- asset depreciation costs
- taxation liabilities
- a commercial return on capital.

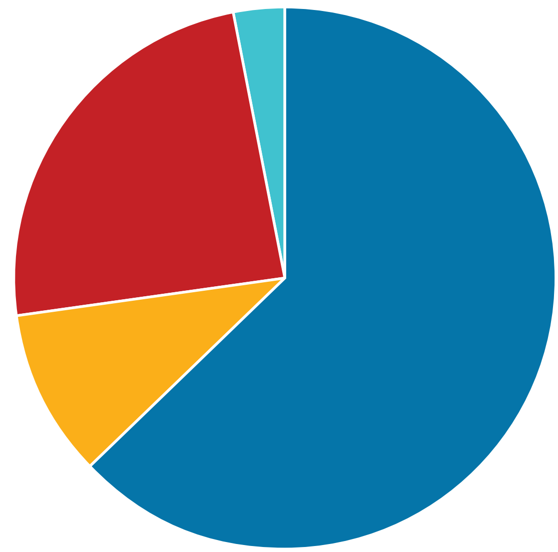
To illustrate, figure 5.5 shows the components of the revenue cap for TransGrid (New South Wales) for the period 2009–10 to 2013–14. For most networks, over 60 per cent of the revenue cap consists of returns on capital.

The AER has developed incentive schemes as part of the regulatory process:

- An *efficiency benefit sharing scheme* provides incentives for transmission businesses to achieve efficient operating and maintenance expenditure in running their networks. The scheme shares efficiency gains between a business and its customers (through lower prices). The scheme applies to all transmission businesses except EnergyAustralia, which is subject to an equivalent distribution business scheme.[9]
- A *service target performance incentive scheme* encourages businesses to maintain or improve network service performance. It acts as a counterbalance to the efficiency benefit sharing scheme so businesses do not reduce costs at the expense of service quality.

  The scheme focuses on network availability and reliability (the frequency and duration of network outages). It also includes a component based on the market impact of transmission congestion (see section 5.7.2). If service performance is above target, the business earns rewards; if performance falls below target, a business may be penalised. The service standards scheme applies to all transmission businesses (although only TransGrid is subject to the congestion component).[10]

Figure 5.5
Composition of TransGrid revenue cap, 2009–10 to 2013–14



Source: AER, *TransGrid transmission determination 2009–10 to 2013–14, final decision*, Melbourne, April 2009.

As part of its role as economic regulator of transmission networks, the AER has developed guidelines to assist stakeholders and to provide regulatory certainty to transmission businesses developing revenue proposals.

9 From 1 July 2009 EnergyAustralia has been subject to the incentive schemes applicable to distribution businesses. For more details on these schemes, see chapter 6.

10 The market impact of transmission congestion component of the scheme will apply to other transmission businesses from the beginning of their next regulatory period. On 30 April 2009, however, Grid Australia submitted a Rule change proposal that would allow a transmission business to elect to be covered by the scheme from an earlier date.

These guidelines include:

- transmission guidelines, which set out the process that businesses must follow in structuring and submitting their revenue proposals for assessment by the AER
- a decision on the parameters of the weighted average cost of capital (WACC) model, which determines the return on capital that a regulated network may recover.[11] The WACC model sets an efficient benchmark for elements including equity raising and debt costs faced by a business when seeking finance. The WACC model applies to all network businesses that submit regulatory proposals after 1 May 2009.
- cost allocation and pricing methodology guidelines, which set out the general principles for allocating costs to, and charges for, services provided by the business
- a post-tax revenue model, which determines the annual revenue requirement needed in each year of the regulatory period to cover a network's cost estimates (or building blocks)
- a roll-forward model, which determines a network's opening RAB, accounting for capital expenditure, asset disposal and depreciation over the previous regulatory period. The model also establishes annual RAB forecasts for the coming regulatory period.

The AER has also provided guidance on other aspects of the regulatory framework, including:

- guidelines on the operation of the regulatory test, which is an analysis tool used by network businesses to assess the efficiency of planned investment (see section 5.8.2)
- a statement of approach detailing the priorities and objectives of annual performance reports on transmission businesses
- ring-fencing guidelines, which set out how transmission businesses that own or operate other network businesses (for example, distribution businesses) are to maintain and separate their accounts.

5.4 Electricity transmission investment

New investment in transmission infrastructure is needed to maintain or improve network performance over time. Investment covers network augmentations (expansions) to meet rising demand and the replacement of ageing assets. Some investment is driven by technological innovations that can improve network performance.

The regulatory process aims to create incentives for efficient investment. At the start of a regulatory period, the AER approves an investment (capital expenditure) forecast for each network. It can also approve contingent projects—large investment projects that are foreseen at the time of the revenue determination, but that involve significant uncertainty about timing and/or costs.

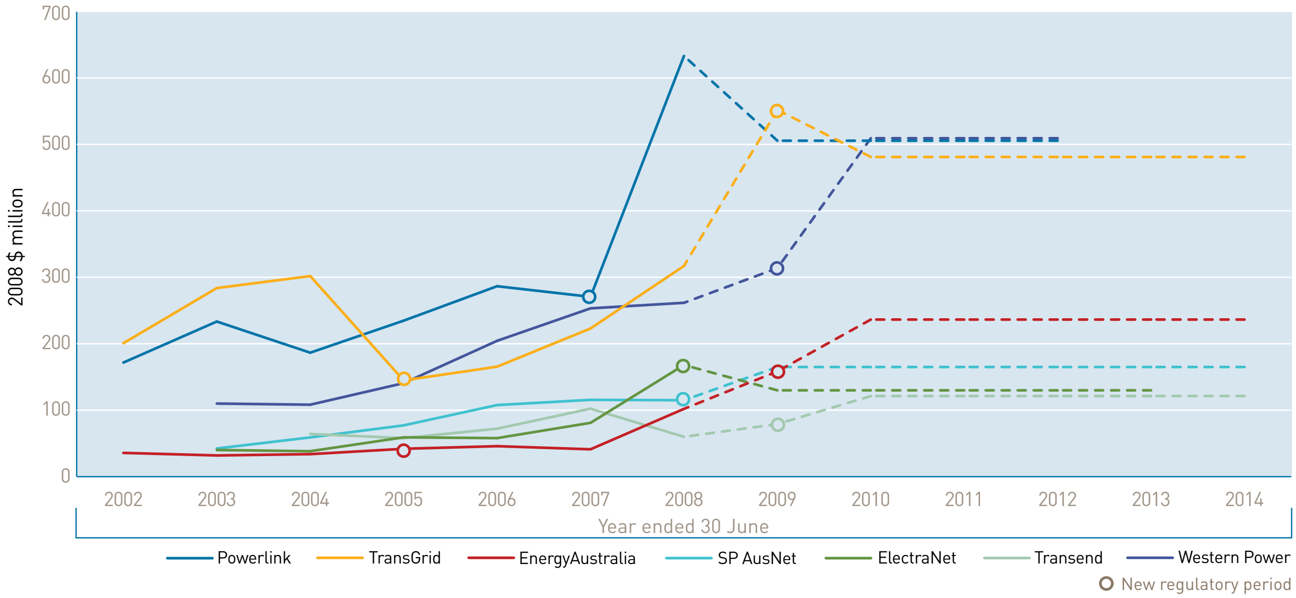
While the regulatory process approves a pool of funds for capital expenditure, individual projects must undergo a regulatory test of economic efficiency. Under the test, a network business must determine that a proposed augmentation passes a cost–benefit analysis, or provides a least cost solution for meeting network reliability standards.[12] The AER is developing a regulatory investment test for transmission (RIT-T) to replace the current regulatory test. The new test will be published by 1 July 2010 (see section 5.8.2).

In determinations since 2005 the AER has allowed network businesses discretion over how and when to spend their investment allowances, without the risk of future review. To encourage efficient spending, network businesses retain a share of any savings (including the depreciation that would have accrued) against their investment allowance. A service standards incentive scheme ensures cost savings are not achieved at the expense of network performance (see section 5.3.2).

11 AER, *Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, final decision*, Melbourne, May 2009.

12 The test comprises a reliability limb (a least cost test for reliability projects) and a market benefits limb (a cost–benefit test for all other projects). See AER, *Regulatory test for network augmentation, version 3*, Melbourne, November 2007.

Figure 5.6
Electricity transmission investment by network



Notes:

Actual data (unbroken lines) are used where available; forecast data (broken lines) are used for other years.

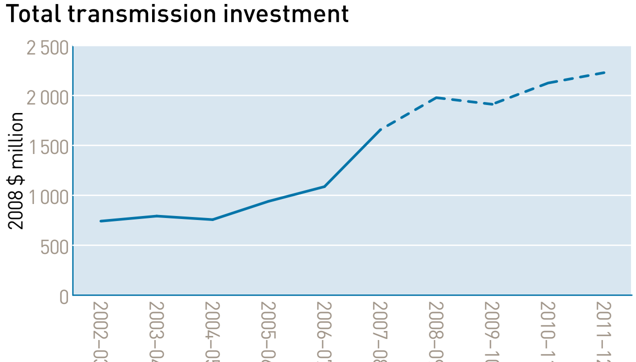
Forecast capital investment is as approved by the regulator through revenue cap determinations (averaged over the regulatory period), except for Western Power where data are from the ERA's draft decision on proposed revisions to Western Power's access arrangement for the period 2009–10 to 2011–12.

For SP AusNet, actual expenditure is replacement expenditure only; forecast expenditure includes network augmentation by AEMO (formerly VENCorp).

All values are converted to June 2008 dollars.

Sources: AER/ACCC annual regulatory reports and revenue cap decisions; ERA performance reports and access arrangement decisions.

Figure 5.7
Total transmission investment



Notes:

Actual data (unbroken lines) are used where available; forecast data (broken lines) are used for other years.

Excludes private interconnectors.

All values are converted to June 2008 dollars.

Sources: AER/ACCC annual regulatory reports and revenue cap decisions; ERA performance reports and access arrangement decisions.

There has been significant investment in transmission infrastructure in the NEM since the shift to national regulation (figures 5.6 and 5.7).[13] Investment levels have been highest for TransGrid and Powerlink. The other networks typically have relatively lower investment levels, reflecting the scale of the networks and differences in investment drivers such as infrastructure age and demand projections.

Care must be taken in interpreting year-to-year changes in investment data. Timing differences between the commissioning of some projects and their completion creates volatility. In addition, transmission investment can be 'lumpy' given the one-off nature of very large capital programs. More generally, because regulated revenues are typically set for five year periods, the network businesses have flexibility to manage and reprioritise their capital expenditure during this time.

13 Figure 5.6 includes Western Power for comparative purposes.

Transmission investment in the major NEM networks totalled around $1.4 billion in 2007–08, equal to around 10 per cent of the combined RABs. Investment was forecast to rise to over $1.6 billion in 2008–9. Investment over the 10 years to 2011–12 (including the Basslink interconnector) is forecast at around $12.4 billion. In Western Australia, investment in 2007–08 reached around $260 million. The Economic Regulation Authority's draft decision for Western Power provides an investment allowance of around $1.5 billion for the three year period starting 1 July 2009.

Recent AER revenue cap decisions project significantly higher investment into the next decade. Forecasts indicate that a step-change rise in investment levels is taking place across the NEM. This reflects substantial real investment in new infrastructure as well as rising resource costs in the energy construction sector.

The Transend, TransGrid and EnergyAustralia revenue determinations in 2009 took account of the changing economic environment. Various input costs (including labour and materials) have recorded slowing growth trends, given the economic downturn. While labour and material costs are still forecast to rise over the regulatory period, the rate of increase is expected to be lower than previously forecast. This expectation contrasts with the revenue determinations for SP AusNet and ElectraNet in 2008, for which input costs were forecast to grow rapidly over the regulatory period.

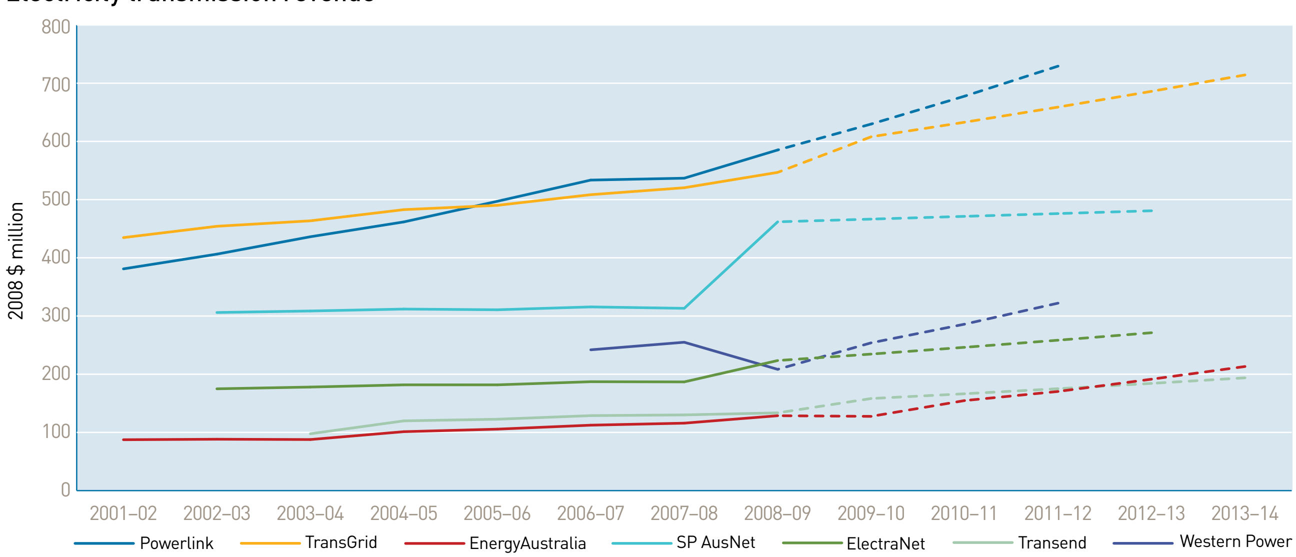
5.5 Financial performance

The AER publishes an annual performance report on the electricity transmission network sector.[14] In addition, new regulatory determinations include both historical performance data for the preceding regulatory period and forecasts of future outcomes.

5.5.1 Revenues

Figure 5.8 charts revenue outcomes for the major transmission businesses, as well as forecast revenues provided through the regulatory process. The year

Figure 5.8
Electricity transmission revenue



Notes:

Actual data (unbroken lines) are used where available; forecast data (broken lines) are used for other years.

All values are converted to June 2008 dollars.

Sources: AER/ACCC annual regulatory reports and revenue cap decisions; ERA performance reports and access arrangement decisions.

14 AER, *Transmission network service providers: electricity performance report for 2007–08*, Melbourne, 2009.

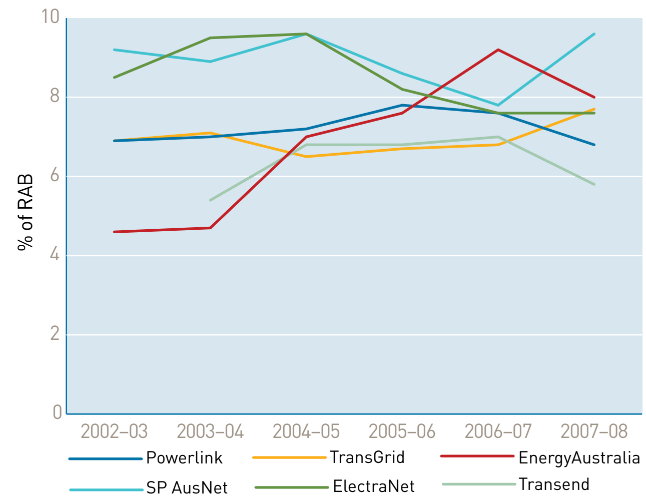
in which the data commence varies across networks, reflecting the staged transfer to national regulation. Different outcomes across the networks reflect differences in scale and market conditions. The revenues of all networks, however, are increasing to meet rising demand. The combined revenue of the NEM's transmission businesses was forecast to exceed $2 billion in 2008–09, representing a real increase of about 30 per cent over five years. Revenue for Western Power was forecast at over $200 million in 2008–09.

Some networks experienced a significant rise in revenues in their first revenue determination under national regulation—for example, in 2003–04 the ACCC allowed revenues for Transend (Tasmania) that were 28 per cent higher than those provided in its previous regulatory period. In addition, the start of a new regulatory period sometimes provides a sharp increase in revenues, reflecting a step-change in capital expenditure—for example, SP AusNet's forecast revenue for 2008–09 (the first year of the current regulatory period) represented a 40 per cent real increase over the previous year's.

5.5.2 Return on assets

The AER's annual regulatory report contains a range of profitability and efficiency indicators for transmission businesses in the NEM.[15] Of these, the return on assets is a widely used indicator of performance. The return on assets is based on operating profits (net profit before interest and taxation) as a percentage of the RAB.[16] Figure 5.9 shows the return on assets for transmission businesses over the six years to 2007–08. In this period, government owned network businesses typically achieved annual returns on assets of 5–8 per cent. The privately owned networks in Victoria and South Australia (SP AusNet and ElectraNet respectively) yielded returns of 7–10 per cent. Outcomes diverged in 2007–08, following convergence over the previous two years.

Figure 5.9
Return on assets for electricity transmission businesses



Sources: AER/ACCC annual performance reports for transmission network service providers.

A variety of factors can affect performance in this area, including differences in the demand and cost environments faced by each business, the rate of return allowed by the regulator, and demand and cost outcomes that differ from those forecast in the regulatory process.

5.5.3 Operating and maintenance expenditure

In setting a revenue cap, the AER allows for efficient operating and maintenance costs. In 2007–08 transmission businesses spent about $420 million on operating and maintenance costs, which was about $50 million below regulatory forecasts. Overall, real expenditure allowances are rising over time in line with rising demand and costs. Three of the six NEM networks, however, incurred lower costs in 2007–08 than in the previous year (figure 5.10). Spending is highest for TransGrid (New South Wales) and Powerlink (Queensland), partly reflecting the scale of those networks. Several factors affect the cost structures

15 AER, *Transmission network service providers: electricity performance report for 2007–08*, Melbourne, 2009, and previous years.
16 The RAB is recalculated annually (with new investment rolled in) for the purposes of this measure.

of transmission companies, including the varying load profiles, load densities, asset age, network designs, local regulatory requirements, topography and climate.

The regulatory framework provides incentives for network businesses to reduce their spending through efficient operating practices. The AER sets expenditure targets and allows a business to retain any underspend in the current regulatory period (and to retain some savings into the next period). The AER also applies a service standards incentive scheme to ensure cost savings are not achieved at the expense of network performance (see section 5.6).

The AER's 2007–08 regulatory report[17] compares target and actual levels of operating and maintenance expenditure. A trend of negative variances between these data sets may suggest a positive response to efficiency incentives. It may be, however, that delays in undertaking some projects deferred the need to operate and maintain those assets. More generally, care must be taken in interpreting year-to-year changes in operating expenditure. The network businesses have some flexibility in managing their expenditure over the regulatory period, so timing considerations may affect the data.

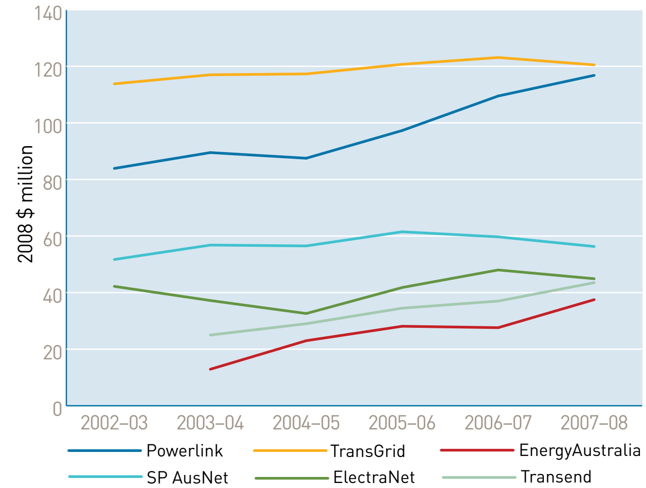
SP AusNet (Victoria) and ElectraNet (South Australia) have spent below their forecast targets since the incentive schemes began in 2002–03 (figure 5.11). TransGrid has underspent every year since 2004–05.

The other networks have tended to spend above target, with large overspends by Transend and EnergyAustralia in 2007–08.

Cost savings should not be achieved at the expense of service quality. AER data indicate that all major networks in eastern and southern Australia have performed satisfactorily against target levels of service quality (see section 5.6).

Figure 5.10

Operating and maintenance expenditure for electricity transmission businesses

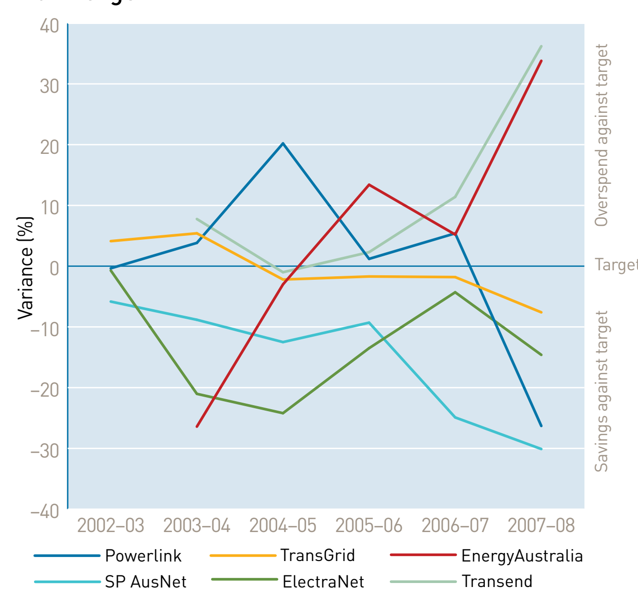


Note: All values are converted to June 2008 dollars.

Sources: AER/ACCC annual performance reports for transmission network service providers.

Figure 5.11

Operating and maintenance expenditure—variances from target



Sources: AER/ACCC annual performance reports for transmission network service providers.

17 AER, *Transmission network service providers: electricity performance report for 2007–08*, Melbourne, 2009.

5.6 Service reliability of electricity transmission networks

Reliability refers to the continuity of electricity supply to customers. Many factors can interrupt the flow of electricity on a transmission network. Interruptions may be planned (for example, due to the scheduled maintenance of equipment) or unplanned (for example, due to equipment failure, bushfires, lightning strikes or the impact of hot weather raising air-conditioning loads above the capability of a network). A serious network failure might require the power system operator to disconnect some customers (known as load shedding).

As in other segments of the power system, there is a trade-off between the price and reliability of transmission services. While the jurisdictions apply different reliability standards, all transmission networks are designed to deliver high rates of reliability. The networks are engineered and operated with sufficient capacity to act as a buffer against planned and unplanned interruptions in the power system. More generally, they enhance the reliability of the power supply as a whole by allowing a diversity of generators to supply electricity to end markets. In effect, the networks provide a mix of capacity that can be drawn on to help manage the risk of a power system failure.

Regulatory and planning frameworks aim to ensure, in the longer term, efficient investment in transmission infrastructure to avoid potential reliability issues. In regulating the networks, the AER approves capital and operating expenditure allowances that network businesses can spend at their discretion. To encourage efficient investment, the AER uses incentive schemes that permit network businesses to retain the returns on any underspend against their allowances. As a counterbalance, a service quality incentive scheme rewards network businesses for maintaining or improving service quality. In combination, capital and operating expenditure allowances and incentive schemes encourage transmission businesses to maintain network reliability over time.

Investment decisions are also guided by planning requirements set by state governments, in conjunction with standards set by AEMO. The state governments vary considerably in their approaches to planning, and in the standards they apply. The Australian Energy Market Commission (AEMC) completed a review of national reliability standards in 2008, to develop a nationally consistent framework (see section 5.8.2).

5.6.1 Transmission reliability data

The Energy Supply Association of Australia (ESAA) and the AER report on the reliability of Australia's transmission networks.

Energy Supply Association of Australia data

The ESAA collects survey data from transmission businesses on reliability, based on system minutes of unsupplied energy to customers. The data are normalised in relation to maximum regional demand to allow comparability.[18]

The data indicate the NEM jurisdictions have generally achieved high rates of transmission reliability (figure 5.12). In 2007–08 total unsupplied energy in all jurisdictions was lower than in the previous year. Unsupplied energy across New South Wales, Victoria and South Australia totalled only 2.1 minutes. New South Wales and Victoria generally experience the least minutes off supply, while Western Australia and Tasmania historically experience the most minutes off supply.

Australian Energy Regulator data

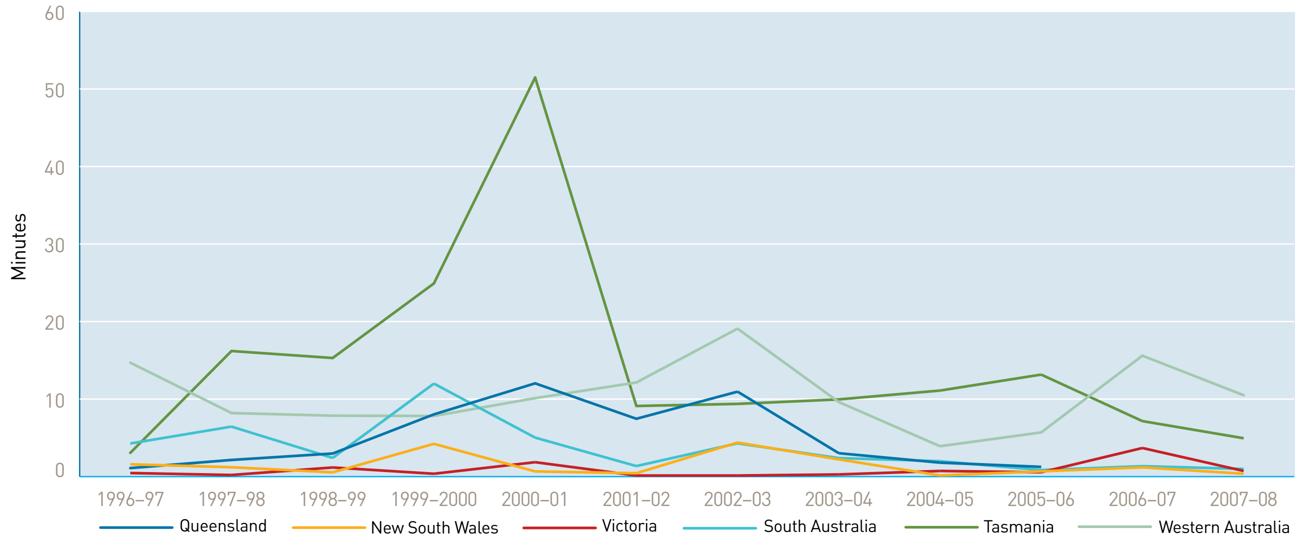
The AER has developed incentive schemes to encourage efficient transmission service quality. The schemes provide financial bonuses (and penalties) to network businesses that meet (or fail to meet) performance targets, which include reliability targets. Specifically, the targets relate to:

> transmission circuit availability
> the average duration of transmission outages
> the frequency of 'off supply' events.

18 System minutes unsupplied are calculated as megawatt hours of unsupplied energy divided by maximum regional demand.

Figure 5.12

Electricity transmission outages—system minutes unsupplied



Note: Data not available for Queensland in 2006–07 and 2007–08.

Source: ESAA, *Electricity gas Australia 2009*, Melbourne, August 2009.

Table 5.2 S-factor values

TRANSMISSION BUSINESSES	2004	2005	2006	2007	2008	
Powerlink (Qld)				0.82		0.53
TransGrid (NSW)	0.93	0.70	0.63	−0.12		0.31
EnergyAustralia (NSW)	1.00	0.67	0.39	−0.14		0.72
SP AusNet (Vic)	0.22	0.09	−0.17	0.06	0.15	0.82
ElectraNet (SA)	0.63	0.71	0.59	0.28	0.29	−0.40
Transend (Tas)	0.55	0.19	0.06	0.56		0.85
Directlink (Qld—NSW)			−0.54	−0.62		−1.00
Murraylink (Vic—SA)			0.21	−0.32		0.69

Notes:

SP AusNet reported separately for the first quarter of 2008 and the remainder of the year.

ElectraNet reported separately for the first and second halves of 2008.

In 2008 SP AusNet transitioned to a new regulatory control period with the financial incentive capped at +1 per cent. Its financial incentive in previous regulatory control periods was capped at +0.5 per cent of its maximum allowable revenue.

Source: AER, *Transmission network service providers: electricity performance report for 2007–08*, Melbourne, August 2009.

Rather than impose a common benchmark target for all transmission networks, the AER sets separate standards that reflect the circumstances of each network based on its past performance. Under the scheme, the over- or underperformance of a network against its targets results in a gain (or loss) of up to 1 per cent of its regulated revenue. A further bonus of up to 2 per cent is available through the transmission congestion component of the scheme (see section 5.7.2).

The revenue at risk may be increased to a maximum of 5 per cent in future regulatory decisions.

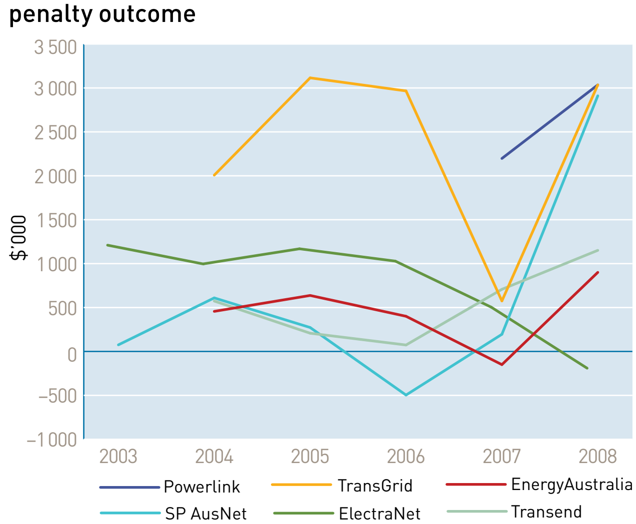
The results are standardised for each network to derive an 's-factor' that can range between −1 and +1. An s-factor of −1 represents the maximum penalty, while +1 represents the maximum bonus. Zero represents a revenue neutral outcome. Table 5.2 sets out the s-factors for each network for the past five years.

The major networks in eastern and southern Australia have generally outperformed their s-factor targets. The only businesses to receive a financial penalty in 2008 were ElectraNet (South Australia), for the second half of the year, and Directlink. Transend received the highest financial reward for 2008 service (0.85 per cent of revenue).

Table 5.3 shows the transmission businesses' performance against their individual targets. While caution must be taken in drawing conclusions from short data series, the major networks appear to have generally performed well against their targets.

Figure 5.13 illustrates the net financial reward or penalty from the scheme for each major network. While the scheme encourages network businesses to improve their performance over time, the financial outcomes relate to individual targets for each network and are not a comprehensive indicator of service quality.

Figure 5.13
Service performance incentive scheme—reward/ penalty outcome



Note: In 2008 SP AusNet transitioned to a new regulatory control period with the financial incentive capped at +1 per cent. Its financial incentive in previous regulatory control periods was capped at +0.5 per cent of its maximum allowable revenue.

Sources: AER, *Transmission network service providers: electricity performance report for 2007–08*, Melbourne, August 2009, and previous years.

5.7 Electricity transmission congestion

Transmission networks do not have unlimited capacity to carry electricity from one location to another. Rather, there are physical limits on the amount of power that can flow over any one part or region of the network. These physical limits arise from the need to prevent damage to the network and ensure stability in the face of small disturbances.

A transmission line can become congested or constrained due to events and conditions on a particular day. Some congestion is caused by factors within the control of a service provider—for example, its scheduling of outages, its maintenance and operating procedures, its standards for network capability (such as thermal, voltage and stability limits), changes in its network monitoring procedures and its decisions on equipment upgrades. Factors beyond the control of the service provider include extreme weather—for example, hot weather can result in high air-conditioning loads that push a network towards its pre-determined limits. To protect system security, AEMO may invoke network constraints. Similarly, line maintenance may limit available capacity. The potential for network congestion is magnified if these events occur simultaneously.

If a major transmission outage occurs in combination with other generation or demand events, it can cause the load shedding of some customers. This is rare in the NEM, however. Rather, the main impact of congestion is on the cost of electricity. In particular, transmission congestion increases the total cost of electricity by displacing low cost generation with more expensive generation. If, for example, a particular transmission line is congested, it can prevent a low cost generator that uses the line from being dispatched to satisfy demand; instead, generators that do not require the constrained line will be used. If higher cost generators are used, then the cost of producing electricity ultimately increases.

Table 5.3 Electricity transmission businesses' performance against targets

POWERLINK (QLD)	TARGET	2004	2005	2006	2007	2008	
Transmission line availability—critical elements (%)	99.07				99.44		98.99
Transmission circuit availability—non-critical elements (%)	98.40				98.70		98.51
Transmission circuit availability—peak hours (%)	98.16				98.60		98.48
Frequency of lost supply events greater than 0.2 system minutes	5				1		2
Frequency of lost supply events greater than 1 system minute	1				0		0
Average outage duration (minutes)	1033				612		1046
TRANSGRID (NSW)	**TARGET**	**2004**	**2005**	**2006**	**2007**	**2008**	
Transmission line availability (%)	99.50	99.72	99.57	99.57	99.38		98.54
Transformer availability (%)	99.00	99.30	98.90	98.84	97.46		98.53
Reactive plant availability (%)	98.50	99.47	99.64	98.92	99.23		99.01
Frequency of lost supply events greater than 0.05 system minutes	5	0	1	2	4		2
Frequency of lost supply events greater than 0.40 system minutes	1	0	0	0	1		0
Average outage duration (minutes)	1500	937	717	812	788		869
ENERGYAUSTRALIA (NSW)	**TARGET**	**2004**	**2005**	**2006**	**2007**	**2008**	
Transmission feeder availability (%)	96.96	98.57	98.30	97.74	96.62		98.41
SP AUSNET (VIC)	**TARGET**	**2004**	**2005**	**2006**	**2007**	**2008**	
Total circuit availability (%)	98.73	99.27	99.34	99.25	99.11	99.44	99.12
Peak critical circuit availability (%)	99.39	99.97	99.94	99.88	99.75	99.49	99.80
Peak non-critical circuit availability (%)	99.40	99.57	99.86	99.79	99.86	99.94	99.93
Intermediate critical circuit availability (%)	98.67	99.80	99.75	99.54	99.32		99.42
Intermediate non-critical circuit availability (%)	98.73	99.39	98.21	98.97	95.78		99.53
Frequency of lost supply events greater than 0.05 system minutes	5	2	5				1
Frequency of lost supply events greater than 0.3 system minutes	1	0	2				1
Average outage duration—lines (minutes)	382	164	452	1856	96	172	226
Average outage duration—transformers (minutes)	412	292	398	431	326	656	263
ELECTRANET (SA)	**TARGET**	**2004**	**2005**	**2006**	**2007**	**2008**	
Transmission line availability (%)	99.25	99.38	99.57	99.42	99.38	99.39	
Total transmission circuit availability (%)	99.47						99.05
Peak critical circuit availability (%)	99.24						97.26
Frequency of lost supply events greater than 0.05 system minutes	4						3
Frequency of lost supply events greater than 0.2 system minutes	2	7	0	4	1	0	1
Frequency of lost supply events greater than 1 system minute	2	0	0	0	0	0	
Average outage duration (minutes)	78	49	114	88	270	203	195
TRANSEND (TAS)	**TARGET**	**2004**	**2005**	**2006**	**2007**	**2008**	
Transmission line availability (%)	99.10–99.20	99.34	98.67	99.21	98.99		99.40
Transformer circuit availability (%)	99–99.10	99.31	99.20	98.80	99.55		99.06
Frequency of lost supply events greater than 0.1 system minutes	13–16	18	13	16	10		6
Frequency of lost supply events greater than 2 system minutes	2–3	0	0	1	0		0

Met target   Below target

Notes:

Performance targets vary across years. The listed target is for 2008. Performance in previous years is measured against the targets for the relevant year.

SP AusNet reported separately for the first quarter of 2008 and the remainder of the year.

ElectraNet reported separately for the first and second halves of 2008.

Sources: AER, *Transmission network service providers: electricity performance report for 2007–08*, Melbourne, August 2009, and previous years.

Table 5.4 Market impact of electricity transmission constraints—Australian Energy Regulator measures

MEASURE	DEFINITION	EXAMPLE
Total cost of constraints (TCC)	The total increase in the cost of producing electricity due to transmission congestion (includes outages and network design limits) > Measures the total savings if all constraints were eliminated.	Hot weather in New South Wales causes a surge in demand for electricity, raising the price. The line between Victoria and the Snowy region reaches capacity, preventing the flow of lower cost electricity into New South Wales to meet the demand. Higher cost generators in New South Wales must be used instead. > TCC measures the increase in the cost of electricity caused by the blocked transmission line.
Outage cost of constraints (OCC)	The total increase in the cost of producing electricity due to outages on transmission networks > Looks at only congestion caused by network outages. > Outages may be planned (e.g. scheduled maintenance) or unplanned (e.g. equipment failure). > Excludes other causes, such as network design limits.	Maintenance on a transmission line prevents the dispatch of a coal fired generator that requires the use of the line. A higher cost gas fired peaking generator (that uses a different transmission line) has to be dispatched instead. > OCC measures the increase in the cost of electricity caused by line maintenance.
Marginal cost of constraints (MCC)	The saving in the cost of producing electricity if the capacity on a congested transmission line is increased by 1 megawatt, added over a year > Identifies which constraints have a significant impact on prices. > Does not measure the actual impact.	See above TCC example. > MCC measures the saving in the cost of producing electricity in New South Wales if one additional megawatt of capacity was available on the congested line. At any time several lines may be congested. The MCC identifies each network element while the TCC and OCC measure the impact of all congestion (and do not discriminate between individual elements).

Congestion can also create opportunities for the exercise of market power. If a network constraint prevents low cost generators from moving electricity to customers, then there is less competition in the market. Subsequently, the remaining generators can adjust their bidding to capitalise on their position, which is likely to result in increased electricity prices.

Not all constraints have the same market impact. Most do not force more expensive generation to be dispatched —for example, congestion that 'constrains off'[19] a coal fired plant and requires the dispatch of another coal fired plant may have little net impact. But the costs may be substantial if cheap coal fired generation needs to be replaced by a high cost peaking plant such as a gas fired generator.

With the assistance of the National Electricity Market Management Company (NEMMCO, now AEMO), the AER completed a project in 2006 to measure the impact of transmission congestion in the NEM. The AER measures the cost of transmission congestion by comparing dispatch costs with and without congestion. It has developed three measures of the impact of congestion on the cost of electricity (table 5.4). Two measures (the total cost of constraints, TCC, and the outage cost of constraints, OCC) focus on the overall impact of constraints on electricity costs, while the third measure (the marginal cost of constraints, MCC) identifies which constraints have the greatest impact.[20]

19 Under the Electricity Rules, 'constrained off' means 'in respect of a generating unit, the state where, due to a constraint on a network, the output of that generating unit is limited below the level to which it would otherwise have been dispatched by AEMO on the basis of its dispatch offer'.

20 A more detailed discussion appears in: AER, *Indicators of the market impact of transmission congestion—decision*, Melbourne, 9 June 2006; AER, annual congestion reports for 2003–04, 2004–05, 2005–06 and 2006–07, Melbourne.

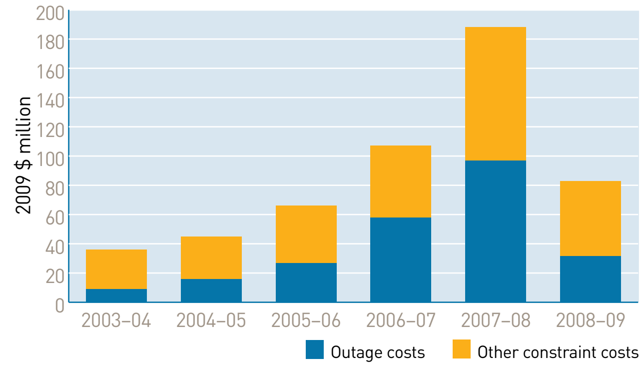
The measures estimate the impact of congestion on generation costs rather than spot prices. In particular, the measures reflect how congestion raises the cost of producing electricity, accounting for the costs of individual generators. If generators' bidding reflects their true cost position, then the measures will be an accurate measure of the economic cost of congestion. The measures reflect, therefore, the negative efficiency effects of congestion and make an appropriate basis for developing incentives to mitigate this cost. If, however, market power allows a generator to bid above its true cost structure, then the measures will reflect a mix of economic costs and monopoly rents. An example of the impact of congestion on the wholesale market is provided in box 5.2.

The AER assesses the impact of major constraints in its weekly market reports. It published four annual congestion reports for the 2003–04 to 2006–07 financial years. These reports assisted in the development of the market impact parameter in the service target performance incentive scheme. This new parameter applied for the first time to TransGrid from July 2009 (see section 5.3.2).

The annual cost of congestion rose from $36 million in 2003–04 to $189 million in 2007–08 but fell to $83 million in 2008–09 (figure 5.14). Typically, most congestion costs accumulate on just a handful of days. Around two thirds of the total cost for 2007–08 accrued on 26 days, with 57 per cent of the costs attributable to network outages. In 2008–09 around two thirds of the total cost accrued on 13 days, with 42 per cent of the costs attributable to network outages.

The data indicate that the cost of network congestion has generally risen over the past six years. In 2008–09 the impact of congestion and particularly network outages was, however, considerably less than for the previous two years. The costs are relatively modest given the scale of the market. Recent regulatory decisions have provided for increased transmission investment that may help to address capacity issues and reduce congestion costs over time.

Figure 5.14
Costs of transmission congestion



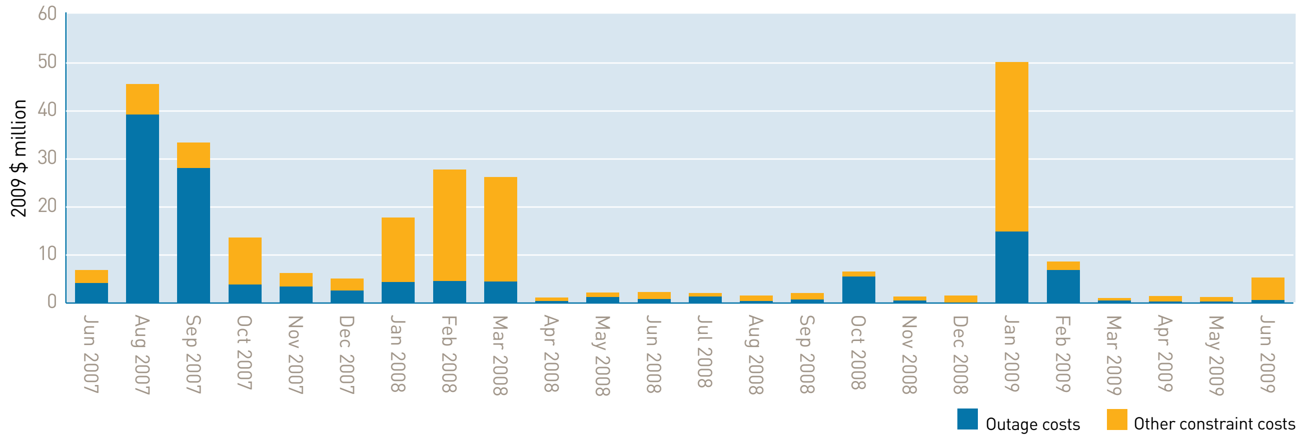
Source: AER.

Figure 5.15 shows congestion on a monthly basis from July 2007 to June 2009. The bulk of congestion costs occurred during the months of August and September 2007 (a result of maintenance outages in Queensland) and over the two summer periods (mainly due to extreme demand in Victoria and South Australia).

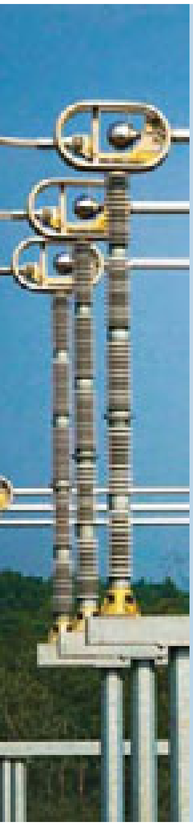
There were significant congestion costs in January and February 2009. Costs totalled $45 million—more than half the total for the financial year—on the last four days of January. In part this was due to a number of unplanned outages on days of high demand—for example, on 29 January the Basslink interconnector and some transmission infrastructure in the Latrobe Valley were out of service.

There were outage costs of $6 million on 7 and 8 February when Victorian bushfires caused significant network outages including on the Victorian to New South Wales interconnector.

Figure 5.15
Monthly costs of transmission congestion for 2007–08 and 2008–09



Source: AER.



Box 5.2 Case study—transmission outages in Victoria

An example of the effects of transmission constraints on energy market outcomes occurred on Wednesday 23 July 2008, when outages of network equipment between Hazelwood Terminal Station and Loy Yang Power Station in Victoria coincided with high winter demand.

For several hours from around 6 pm that evening, two of the three Hazelwood to Loy Yang 500 kV lines were out of service: the first to investigate an equipment alarm triggered early that morning, and the other following an unplanned outage due to the incorrect action of protection equipment. Only one line was left connecting Loy Yang A and B power stations and Tasmania to the rest of the market. This reduced electricity production from Loy Yang by around 1000 megawatts and prevented any flows into Victoria across BassLink.

Due to the risk of losing the remaining Hazelwood to Loy Yang line, the requirement for frequency control ancillary services to cover this contingency increased significantly—the 6 second requirement increased from 212 MW to 1076 MW, the 60 second requirement from 212 MW to 1538 MW and the 5 minute requirement from 406 MW to 1731 MW. The prices for those services rose to the price cap. The cost of ancillary services that evening totalled around $118 million—compared with less than $60 million for the rest of 2008–09. At the same time, generators reduced energy output to provide these services. This reduced the dispatch of low priced energy generation by more than 1 gigawatt.

As a result of the reduced availability of low priced generation, combined with record winter demand, the spot price for each of the mainland regions exceeded $8000 per megawatt hour for the 6.30 pm trading interval. The total cost of congestion for this event was $1.6 million, with outage cost accounting for $1.2 million.

5.7.1 Geography of transmission congestion

Around 1200 network constraints affected the market at least once in 2007–08 and 2008–09. At any one time, between 550 and 650 constraints were typically in place. Congestion may be significant in a particular area for only a few days a year, but this is sometimes sufficient to have a significant impact on congestion costs.

Figure 5.16 shows the locations of significant congestion over the past six years. Locations of congestion may change from year to year due to conditions such as drought, weather events and unscheduled line outages. In 2007–08 and 2008–09, there was congestion in northern Tasmania; in Victoria's Latrobe Valley around Hazelwood; in South Australia (mainly in the south east and around Mintaro); and Queensland. Congestion between central Queensland and the load centre in Brisbane has affected the market every year. There was also congestion in northern and central Queensland and on the Middle Ridge to Tangkam transmission line.

There was also congestion on interconnectors between regions, including on the Heywood interconnector (Victoria to South Australia), across QNI (Queensland to New South Wales) and across the Snowy interconnector (Victoria to New South Wales).

5.7.2 Measures to reduce congestion costs

The AER recognises the significance of congestion costs and has responded to the issue by:

> developing measures of the market impact of transmission constraints and publishing data against these measures (as outlined)
> implementing an incentive scheme to reduce transmission constraints
> providing for rising transmission investment in regulatory decisions.

Other responses include the AEMC congestion management review, which aimed to enhance mechanisms to manage congestion in the NEM. The review considered options such as congestion pricing, changes to regional pricing structures and deeper connection charges (see section 5.8.4). In addition, the Ministerial Council on Energy (MCE) has implemented national transmission planning arrangements which are expected to reduce congestion through enhanced whole-of-NEM network planning (see section 5.8.1).

Further, the AEMC congestion management review recommended that AEMO develop a Congestion Information Resource to provide cost-effective information to participants, to enable them to understand patterns of network congestion and project market outcomes. The review recommended that the resource provide the most recent information on network outages and other planned network events. This would provide participants with a better understanding of how potential changes in system conditions are likely to affect their market risks, allowing for more informed decision making. The AEMC published its decision on changes to the Electricity Rules in August 2009. AEMO is required to publish an interim by March 2010, guidelines by September 2010 and its first final resource by September 2011.

Congestion management incentive scheme

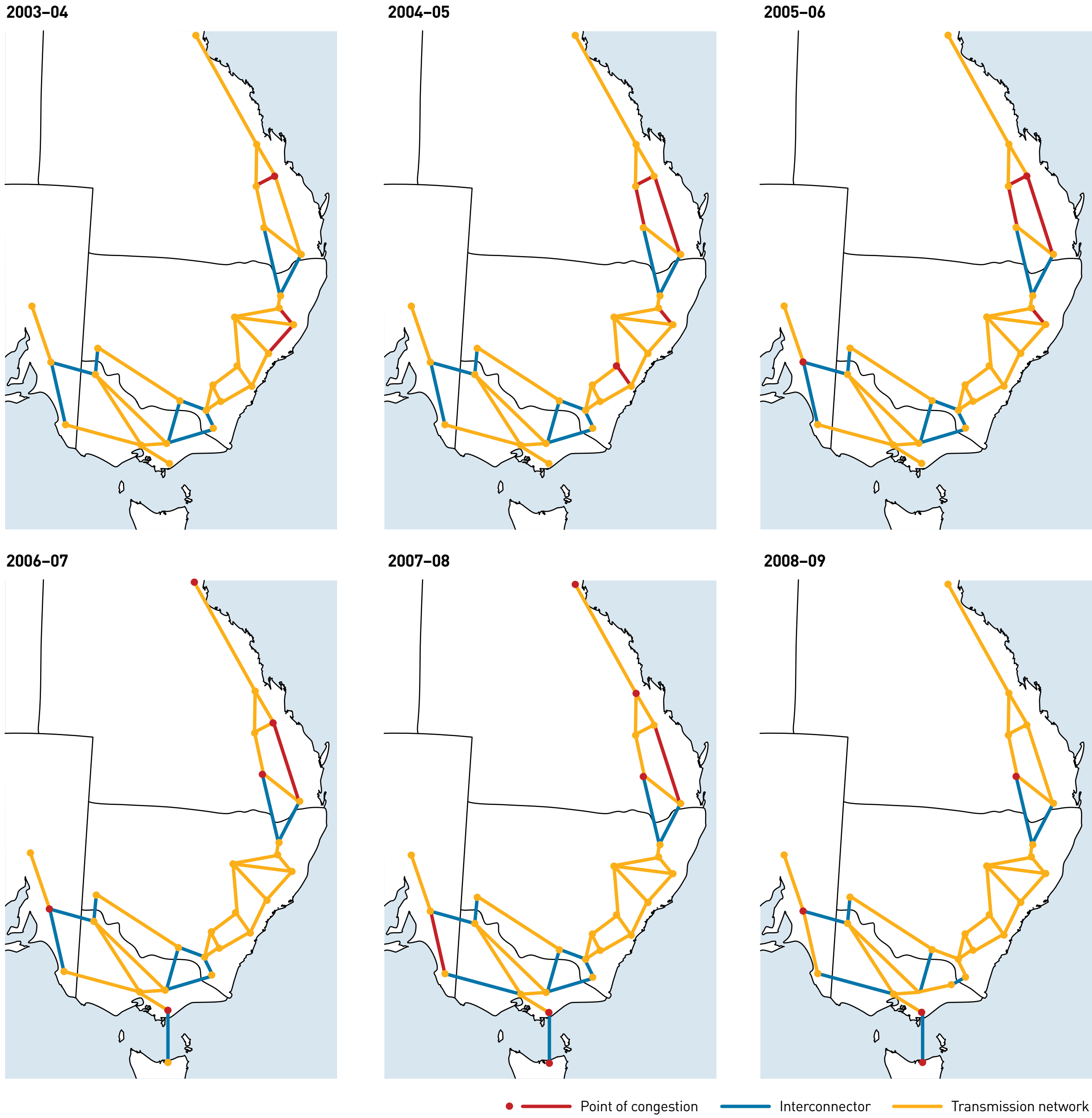
The AER introduced a new incentive mechanism in 2008 to reduce the effects of transmission congestion. The mechanism forms part of the service performance incentive scheme and is designed to encourage network owners to account for the impact of their behaviour on the market.[21] The mechanism operates as a bonus-only scheme. It aims to reward network owners for improving operating practices in areas such as outage timing, outage notification, live line work and equipment monitoring. In some cases, these improvements may be more cost-efficient measures to reduce congestion than solutions that require investment in infrastructure.

The mechanism permits a transmission business to earn an annual bonus of up to 2 per cent of its revenue if it can eliminate all outage events with a market impact of over $10 per megawatt hour.[22]

21 AER, *Electricity transmission network service providers: service target performance incentive scheme*, Melbourne, March 2008.

22 The level of performance improvement required to receive the full 2 per cent bonus is probably an unrealistic aim. It may be difficult to determine a realistic level of performance, however, until the scheme has been in place for a period of time.

Figure 5.16
Congestion within regions of the National Electricity Market



Source: AER.

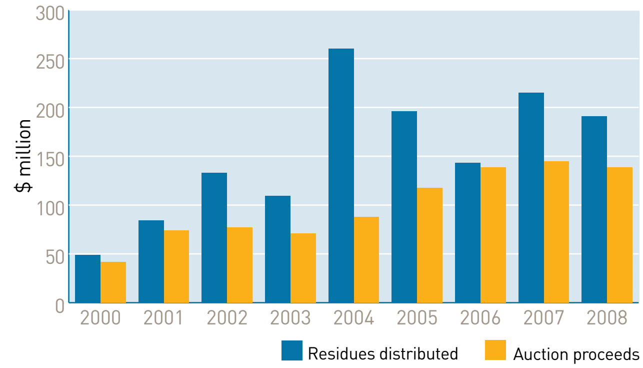
5.7.3 Settlement residue auctions

Congestion in transmission interconnectors can cause wholesale electricity prices to differ across the regions of the NEM (see section 2.4). In particular, prices may spike in a region that is constrained in its ability to import electricity. To the extent that trade remains possible, electricity will flow from lower to higher price regions. Consistent with the regional design of the NEM, the exporting generators are paid at their local regional spot price, while importing retailers must pay the higher spot price in their region. The difference between the price paid in the importing region and the price received in the generating region, multiplied by the amount of flow, is called a settlement residue. Figure 2.8 (chapter 2) charts the annual accumulation of settlement residues in each region of the NEM.

Price separation creates risks for the parties that contract across regions. AEMO offers a risk management instrument by holding quarterly auctions to sell the rights to future residues up to one year in advance.[23] Retailers, generators and other market participants may bid for a share of the residues—for example, a Queensland generator, trading in New South Wales, may bid for residues between those regions if it expects New South Wales prices to settle above Queensland prices. New South Wales is a significant importer of electricity, so it can be vulnerable to price separation and often accrues high settlement residue balances.

Figure 5.17 charts the amount of settlement residues that accrued each year against the proceeds of residue auctions from 2000 to 2008. The total value of residues represents the net difference between the prices paid by retailers and the prices received by generators across the NEM. It approximates, therefore, the risk faced by market participants from interregional trade. The figure illustrates that the residues are frequently auctioned for less than their ultimate value. On average, the actual residues have been around 55 per cent higher than the auction proceeds.

Figure 5.17
Interregional hedging—auction proceeds and settlement residues



Source: AEMO.

Market participants tend to discount the value of settlement residues because they are not a firm hedging instrument. In particular, a reduction in the capability of an interconnector—for example, due to an outage—reduces the cover that the hedge provides. This makes it difficult for parties to assess the amount of hedging for which they are bidding at the residue auctions. The auction units are, therefore, a less reliable risk management tool than some other financial risk instruments, such as those traded in over-the-counter and futures markets (see chapter 3).

5.8 Policy developments in electricity transmission

Recent policy activity in the transmission sector has focused on network planning and operation and the approach to economic regulation. This section summarises policy developments in these areas. Appendix A describes the institutional bodies and organisations with responsibility for developing and implementing energy policy.

23 In September 2009 AEMO began consultation on a proposal to extend auctions from one to three years.


Mark Wilson

5.8.1 Australian Energy Market Operator and the National Transmission Planner

In July 2009 AEMO began operating as a single, industry funded national energy market operator for both electricity and gas. It merges the roles of the national electricity market operator (previously undertaken by NEMMCO) with the gas market operators in New South Wales, the ACT, Queensland, Victoria and South Australia. It also assumes the state based electricity planning functions of VENcorp (in Victoria) and the Electricity Industry Supply Planning Council (in South Australia).

AEMO also undertakes new functions, including:

- the planning and coordination of development of the national transmission network
- the preparation of a gas statement of opportunities (see chapter 8).

The National Transmission Planner (NTP) role aims to strengthen transmission planning arrangements in the NEM. In particular, it will attempt to move the planning focus away from priorities within individual jurisdictions, onto the national grid as a whole.

An annual national transmission network development plan will outline the efficient development of the power system. It will provide a long term strategic outlook (minimum 20 years), focusing on national transmission flow paths. It will not replace local planning and will not be binding on transmission businesses or the AER. Rather, the plan will complement shorter term investment planning by transmission businesses.

5.8.2 Regulatory test for investment

The regulatory test is an analysis tool that network businesses use to assess the efficiency of planned investment. It identifies the most effective network augmentation or non-network option for meeting an identified investment need.

In July 2009 the AEMC completed a rule change to replace the regulatory test with the Regulatory Investment Test for Transmission (RIT-T).[24] The new test removes the distinction between reliability driven projects and those driven by the delivery of market benefits. All projects will now be assessed through a single consultation and assessment framework, which aims to identify investments that promote efficiency and, where applicable, meet reliability standards.

The revised assessment process is more comprehensive than the previous process set out in the Electricity Rules, and applies to a wider range of investment projects. It involves greater prescription in the Electricity Rules of the market benefits and costs that the analysis can consider, and a new market benefit category covering an asset's option value. The AER will develop and publish the RIT-T and associated guidelines by July 2010.

5.8.3 Climate change (review of energy market frameworks)

The AEMC has reviewed the likely impacts of climate change policies—particularly the carbon pollution reduction scheme and expanded renewable energy target —on energy market frameworks. It released the final report in October 2009.

The AEMC identified the connection process for new generators as a weakness in the Electricity Rules.[25] The current process is unlikely to cope with a large increase in connection applications that may result from the introduction of climate change policies—particularly for new investment in renewable generation that may be clustered in certain geographic locations and remote from customers and the transmission network. In particular:

- the current bilateral negotiation framework is unlikely to lead to the development of appropriately by sized connection assets to cater for expected future demand for network access

24 AEMC, National Electricity Amendment (Regulatory Investment Test for Transmission) Rule 2009 No. 15, Sydney

25 AEMC, *Review of energy market frameworks in light of climate change policies, final report*, Sydney, October 2009.

- confidentiality provisions limit the opportunity to coordinate multiple connection applications, leading to delays and additional costs in the connection process.

To take advantage of economies of scale in network assets, the AEMC has recommended a new framework for developing network extensions for remote generation. The framework will coordinate connection applications, with the extension assets sized to allow for expected growth in demand for network access. Customers will bear the risk of oversized connection assets.

In May 2009 the AEMC published a draft rule determination to amend the confidentiality provisions for network connection applications. The change is designed to allow for greater coordination of connection applications.

The AEMC also considered that climate change policies may result in higher levels of network congestion within and across regions. It suggested stronger signals for generator entry location and generator exit could help resolve this issue. The signals could be provided through a combination of generator transmission charges (revenue neutral within each region) and constraint pricing at points in the network experiencing ongoing congestion.

The AEMC also proposed a model for interregional transmission charging. Under current arrangements, customers in an importing region of the NEM do not pay transmission businesses in the exporting region the costs incurred to serve their load. The AEMC supports the introduction of a load export charge that would treat the transmission business of the importing region as a customer of the transmission business of the exporting region. All charges to the network would ultimately be recovered from the network's customers.

5.8.4 Congestion management

While the reliability of transmission networks in the NEM is consistently high, network congestion sometimes impedes the dispatch of the most cost-efficient generation to satisfy demand. The AEMC finalised a congestion management review in 2008 that considered the scope for enhanced market based solutions to manage trading risks.[26]

Following the review, the MCE initiated a rule change to implement the main recommendations. These included:

- formalising in the Electricity Rules AEMO's current process for determining which generators to dispatch in the market
- amending the Electricity Rules to reduce financial uncertainty for holders of settlement residue units, including new arrangements to manage and fund negative settlement residues
- publishing a congestion information resource by AEMO to consolidate and enhance information on network congestion.

In 2008 the AER launched a scheme that provides incentives for network businesses to better manage factors within their control that can lead to transmission congestion—for example, the scheduling of outages (see section 5.7.2).[27]

5.8.5 Jurisdictional reliability standards

The Energy Reform Implementation Group reported in 2007 that the current transmission reliability standards set by the jurisdictions need greater clarity and transparency. In particular, it formed a view that clause 5.1 of the Electricity Rules and the majority of jurisdictional reliability obligations require significant interpretation.[28]

26 AEMC, *Congestion management review, final report*, Sydney, June 2008

27 AER, *Service target performance incentive scheme version 2*, Melbourne, March 2008.

28 ERIG, *Energy reform—the way forward for Australia*, Report to the Council of Australian Governments, Canberra, January 2007.

In response, the AEMC Reliability Panel undertook a review of jurisdictional transmission reliability standards. In August 2008 the AEMC released a final report endorsing the findings of the panel and setting out its preferred option for a nationally consistent framework.[29] Key features of the framework include:

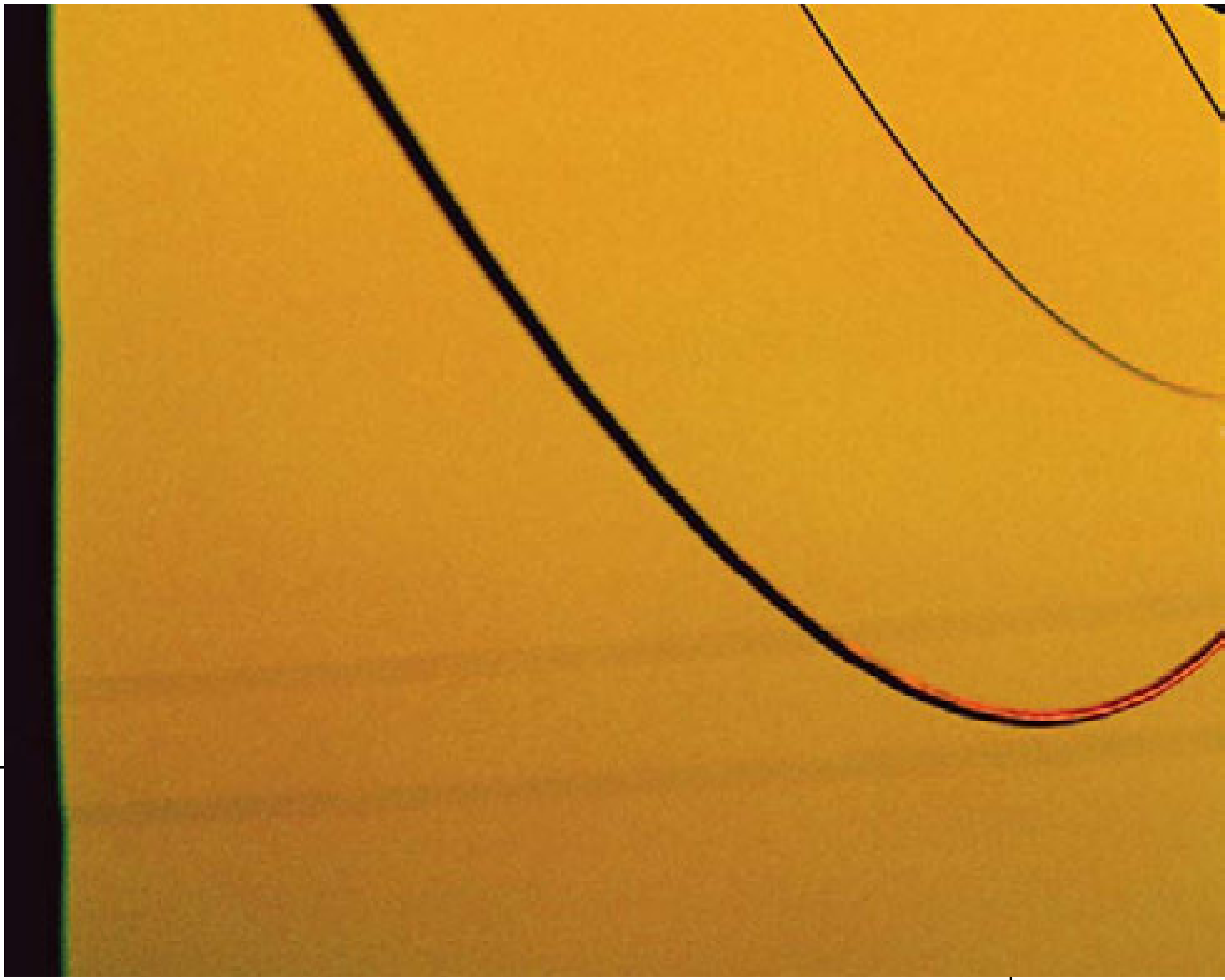
> economically derived and deterministically expressed standards set on a jurisdictional basis by independent jurisdictional authorities
> the introduction of a national reference standard to compare reliability standards across jurisdictions
> a clear and transparent standard setting process.

5.8.6 Jurisdictional technical standards

In April 2009 the AEMC Reliability Panel completed an initial review of jurisdictional transmission technical standards.[30] The final report set out guiding principles on which to base a detailed review of the technical standards in the NEM, and it suggested minor changes to allow more efficient compliance.

The panel recommended deferring a detailed review until sufficient new connections have taken place under the current technical standards to better assess their effectiveness.

29 AEMC, *Towards a nationally consistent framework for transmission reliability standards, final report*, Sydney, September 2008.
30 AEMC Reliability Panel, *Technical standards review, final report*, Sydney, April 2009.



6 ELECTRICITY DISTRIBUTION


Jay Dickman (Corbis)

Most electricity customers are located a long distance from generators. The electricity supply chain thus requires networks to transport power from generators to customers. Chapter 5 provides a survey of high voltage transmission networks that move electricity over long distances. This chapter focuses on the lower voltage distribution networks that move electricity from points along the transmission line to customers in cities, towns and regional communities.

6 ELECTRICITY DISTRIBUTION

This chapter considers:

> the role of the electricity distribution network sector
> the structure of the sector, including industry participants and ownership changes over time
> the economic regulation of the distribution network sector
> financial outcomes, including revenues and returns on assets
> new investment in distribution networks
> quality of service, including reliability and customer service performance.

There are a number of ways to present and analyse data on Australia's electricity distribution networks. This chapter mostly adopts a convenient classification of the networks based on jurisdiction and ownership criteria. Other possible ways to analyse the data include by feeder—for example, a rural—urban classification. Section 6.6 includes analysis based on a feeder classification.

While this chapter includes data that might enable performance comparisons across networks, such comparative analysis should note that geographic, environmental and other differences can affect relative performance.

6.1 Role of distribution networks

Distribution networks move electricity from transmission networks to residential and business customers.[1] A distribution network consists of the poles, underground channels and wires that carry electricity, as well as substations, transformers, switching equipment, and monitoring and signalling equipment. While electricity moves along transmission networks at high voltages to minimise energy losses, it must be stepped down to lower voltages in a distribution network for safe use by customers. Most customers in Australia require delivery at around 230–240 volts.

Distribution networks criss-cross urban and regional areas to provide electricity to every customer. This requires substantial investment in infrastructure. The total length of distribution infrastructure is around 750 000 kilometres in the National Electricity Market (NEM) and around 100 000 kilometres in Western Australia and the Northern Territory—17 times longer than transmission infrastructure.

In Australia, electricity distributors provide the infrastructure to transport electricity to household and business customers, but they do not sell electricity. Instead, retailers bundle electricity generation with transmission and distribution services, and sell them as a package (see chapter 7). In some jurisdictions, there is common ownership of distributors and retailers, which are ring-fenced (operationally separated) from one another.

The contribution of distribution costs to final retail prices varies across jurisdictions, customer types and locations. The Queensland Competition Authority (QCA) reported in 2009 that distribution services account for about 36.5 per cent of a typical residential electricity bill.[2] The Essential Services Commission (ESC) of Victoria reported in 2004 that distribution can account for 30–50 per cent of retail prices, depending on customer type, energy consumption, location and other factors.[3]

6.2 Australia's distribution networks

Australia has 16 major electricity distribution networks, of which 13 are located in the NEM. Table 6.1 provides summary details. Queensland, New South Wales, Victoria and Western Australia have multiple networks, of which each is a monopoly provider in a designated area. In the other jurisdictions, there is one major network. There are also small regional networks with separate ownership in some jurisdictions. Figure 6.1 illustrates the distribution network areas for Queensland, New South Wales, the Australian Capital Territory (ACT) and Victoria. Figure 4.1 in chapter 4 illustrates the network areas for Western Australia.

6.2.1 Ownership

Table 6.1 sets out ownership arrangements for Australian distribution networks. At June 2009:

- Victoria and South Australia's networks are privately owned or leased, and the ACT network has joint government and private ownership
- New South Wales, Queensland, Tasmania and the non-NEM jurisdictions of Western Australia and the Northern Territory have retained government ownership of the electricity distribution sector.

1 There are exceptions. Some large businesses (such as aluminium smelters), for example, can bypass the distribution network and source electricity directly from the transmission network. Conversely, embedded generators have no physical connection with the transmission network and dispatch electricity directly into a distribution network.

2 QCA (Queensland), *Final decision—benchmark retail cost index for electricity: 2009–10*, Brisbane, June 2009, p. 54.

3 ESC (Victoria), *Electricity distribution price review 2006–10, issues paper*, Melbourne, December 2004, p. 5.

Table 6.1 Electricity distribution networks

NETWORK	LOCATION	CUSTOMER NUMBERS	LINE LENGTH (KM)	ENERGY DELIVERED (GWH), 2007–08	MAXIMUM DEMAND (MW), 2007–08	DISTRIBUTION LOSSES (%), 2007–08
NEM REGIONS						
QUEENSLAND						
ENERGEX	Brisbane, Gold Coast, Sunshine Coast and surrounds	1 270 734	51 349	20 879	4 142	5.7
Ergon Energy	Country and regional Queensland	766 453	146 339	13 813	2 313	6.5
NEW SOUTH WALES AND THE ACT						
EnergyAustralia	Inner, northern and eastern metropolitan Sydney and surrounds	1 580 933	49 556	30 624	5 683	4.3
Integral Energy	Southern and western metropolitan Sydney and surrounds	853 322	33 299	17 586	3 317	4.1
Country Energy	Country and regional NSW; southern regional Queensland	780 222	205 133	11 973	2 329	7.0
ActewAGL	All of the ACT	158 455	4 696	2 799	599	4.5
VICTORIA						
Powercor	Western Victoria	668 680	82 459	10 299	2 066	6.6
SP AusNet	Eastern Victoria	592 263	46 039	7 500	1 596	6.0
United Energy	South eastern metropolitan Melbourne	619 666	12 858	7 891	1 735	3.9
CitiPower	Inner metropolitan Melbourne	297 568	6 485	6 079	1 338	4.1
Jemena	Western metropolitan Melbourne	299 662	5 775	4 378	867	5.5
SOUTH AUSTRALIA						
ETSA Utilities	All of South Australia	786 800	85 833	11 380	2 847	5.5
TASMANIA						
Aurora Energy	All of Tasmania	265 524	24 641	4 487	1 073	1.1
NEM TOTALS						
NON-NEM REGIONS						
WESTERN AUSTRALIA						
Western Power	South western Western Australia	973 516	85 182	14 500	3 420	
Horizon Power	North western Western Australia	37 508	7 747			
NORTHERN TERRITORY						
Power and Water	All of the Northern Territory	74 097	7 311			7.0[5]

	ASSET BASE (2008 $ MILLION)[1]	INVESTMENT—CURRENT PERIOD (2008 $ MILLION)[2]	CURRENT REGULATORY PERIOD	OWNER
	4 778	3 077	1 July 2005 – 30 June 2010	Qld Government
	4 656	3 147	1 July 2005 – 30 June 2010	Qld Government
	7 184	6 535	1 July 2009 – 30 June 2014	NSW Government
	3 633	2 679	1 July 2009 – 30 June 2014	NSW Government
	4 252	3 767	1 July 2009 – 30 June 2014	NSW Government
	589	271	1 July 2009 – 30 June 2014	ACTEW Corporation (ACT Government) 50%; Jemena (Singapore Power International (Australia)) 50%
	1 849	905	1 Jan 2006 – 31 Dec 2010	Cheung Kong Infrastructure/ Hongkong Electric Holdings 51%; Spark Infrastructure 49%
	1 486	714	1 Jan 2006 – 31 Dec 2010	SP AusNet (listed company; Singapore Power International 51%)
	1 387	550	1 Jan 2006 – 31 Dec 2010	Jemena (Singapore Power International (Australia)) 34%; DUET Group 66%
	1 126	520	1 Jan 2006 – 31 Dec 2010	Cheung Kong Infrastructure/ Hongkong Electric Holdings 51%; Spark Infrastructure 49%
	657	239	1 Jan 2006 – 31 Dec 2010	Jemena (Singapore Power International (Australia))
	2 771	846	1 July 2005 – 30 June 2010	Cheung Kong Infrastructure/ Hongkong Electric Holdings 51%; Spark Infrastructure 49%
	1 072	566	1 Jan 2008 – 20 June 2013	Tas Government
	2 574[3]	1 392[3]	1 July 2009 – 30 June 2012[4]	WA Government
				WA Government
	500[5]		1 July 2009 – 30 June 2014	NT Government

1. Asset valuation is the opening regulated asset base for the current regulatory period, converted to June 2008 dollars.
2. Investment data are forecast capital expenditure over the current regulatory period, converted to June 2008 dollars.
3. Data from the ERA's draft decision on proposed revisions to Western Power's access arrangement for the period 2009–10 to 2011–12.
4. At July 2009 Western Power's access arrangement for the period 2009–10 to 2011–12 was not finalised. Network prices for 2009–10, therefore, have been established under the previous access arrangement.
5. Includes transmission network assets.

Principal sources: Regulatory determinations and performance reports published by the AER (NSW and the ACT), the QCA (Qld), IPART (NSW), the ESC (Vic), ESCOSA (SA), the ERA (WA), OTTER (Tas), the ICRC (ACT) and the Utilities Commission (NT).

Figure 6.1

Electricity distribution network areas—Queensland, New South Wales, the ACT and Victoria

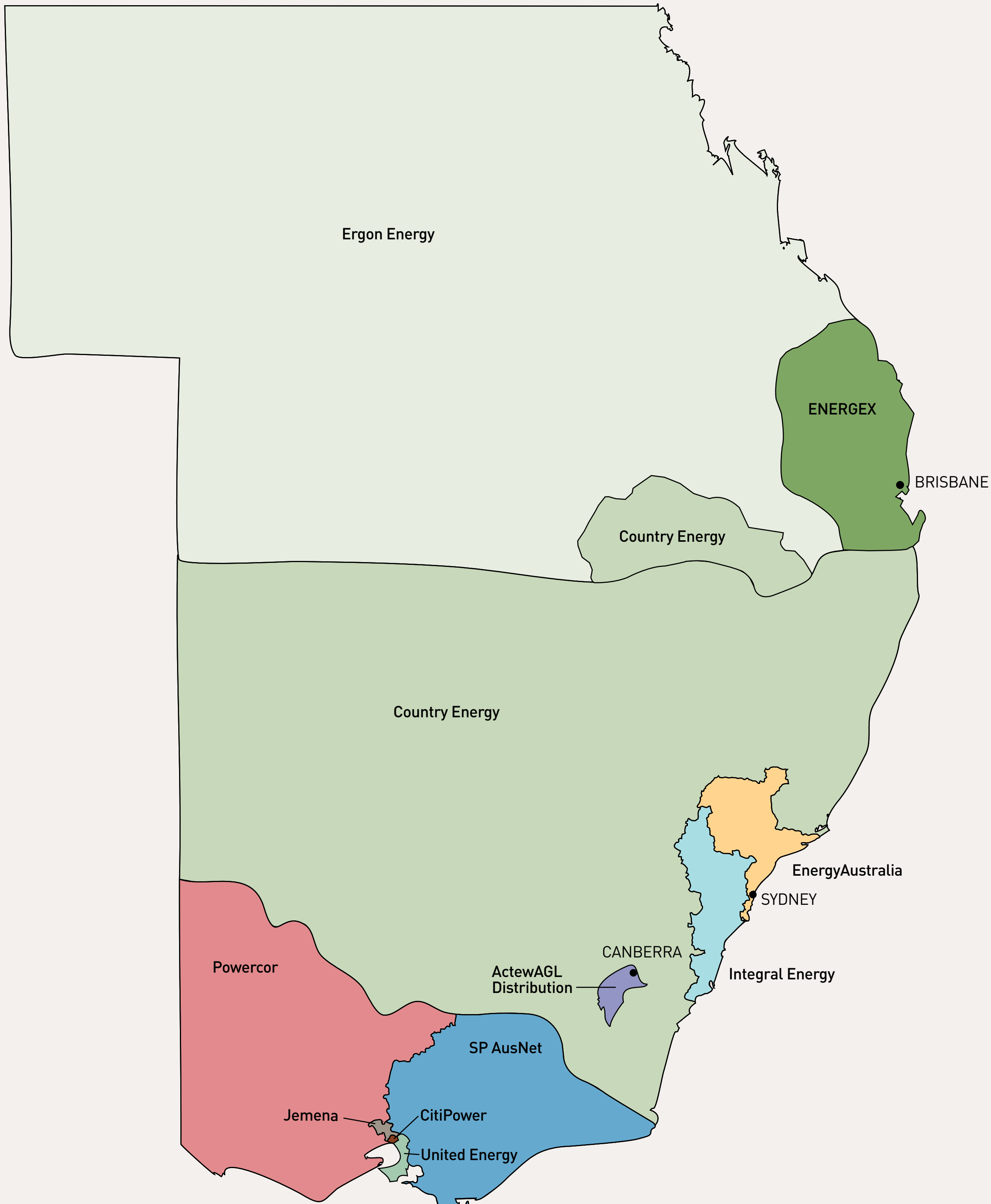
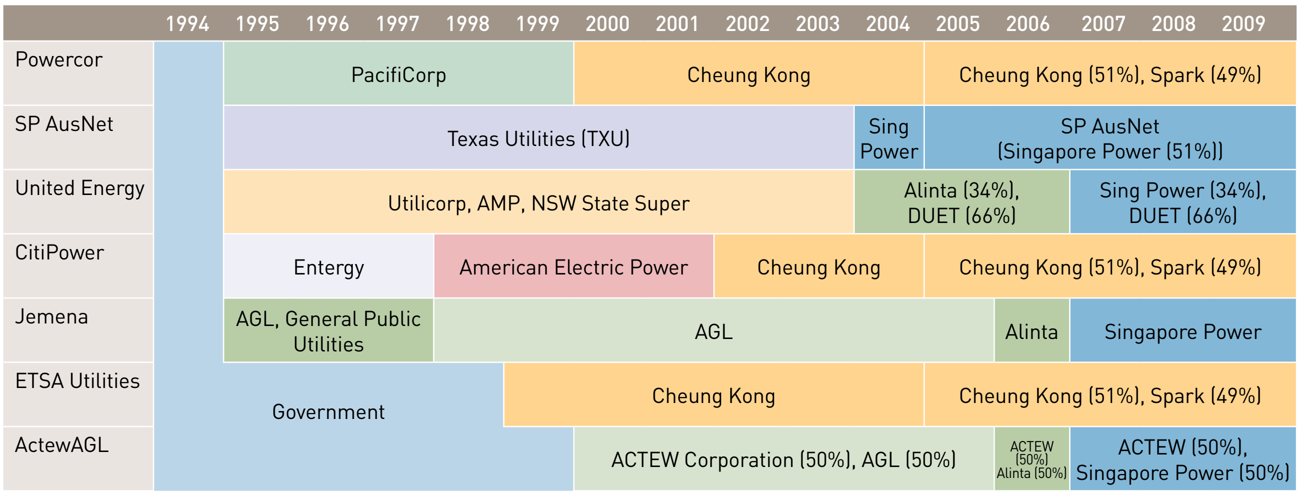


Figure 6.2

Electricity distribution networks—private ownership



Note: Some corporate names have been abbreviated or shortened.

Victoria's five distribution networks—Powercor, SP AusNet, United Energy, CitiPower and Jemena—are privately owned. The South Australian network (ETSA Utilities) is leased to private interests. Figure 6.2 tracks ownership changes since privatisation. At June 2009 there are two principal network owners:

> Cheung Kong Infrastructure and Hongkong Electric Holdings have a 51 per cent stake in two Victorian networks (Powercor and CitiPower) and a 200-year lease of the South Australian distribution network (ETSA Utilities). The remaining 49 per cent in each network is held by Spark Infrastructure, a publicly listed infrastructure fund in which Cheung Kong Infrastructure has a direct interest.

> Singapore Power International owns a 51 per cent stake in SP AusNet, which owns Victoria's SP AusNet network. Singapore Power International acquired a second Victorian network (Jemena) and part ownership of a third network (United Energy) from Alinta in 2007. It also owns a 50 per cent share in the ACT distribution network (ActewAGL).

DUET Group has a majority interest in Victoria's United Energy network.[4] The minority owner, Singapore Power International, operates the network.

6.2.2 Cross-ownership

In some jurisdictions, there are ownership links between electricity distribution and other segments of the energy sector. In New South Wales, Tasmania and the ACT, common ownership occurs in electricity distribution and retailing, with ring-fencing arrangements for operational separation.[5] Queensland privatised much of its energy retail sector in 2006–07, but Ergon Energy continues to jointly provide distribution and retail services. In Western Australia, Western Power owns both electricity transmission and distribution assets. Horizon Power in Western Australia and Power and Water in the Northern Territory are vertically integrated electricity businesses.

The private electricity distributors also provide other energy network services. The most significant is Singapore Power International, which owns electricity transmission and distribution networks, and gas transmission and distribution pipelines. Cheung Kong Infrastructure has an interest in gas distribution pipelines through its 19 per cent stake in Envestra.

4 DUET Group comprises a number of trusts, for which Macquarie Bank and AMP Capital Holdings jointly own the responsible entities.

5 In the ACT, ACTEW Corporation has a 50 per cent share in ActewAGL Retail and ActewAGL Distribution. AGL Energy and Singapore Power International respectively own the remaining shares.


Mark Wilson

6.3 Economic regulation of distribution services

Electricity distribution networks are capital intensive and incur declining marginal costs as output increases, thus realising economies of scale. This gives rise to a natural monopoly structure. In the NEM, the networks are regulated under the National Electricity Law (Electricity Law) and the National Electricity Rules (Electricity Rules) to manage the risk of monopoly pricing and ensure the reliability, safety and security of the power system.

On 1 January 2008 the Australian Energy Regulator (AER) acquired responsibility for the economic regulation of electricity distribution—previously the responsibility of state and territory regulators. The regulation of distribution networks in Western Australia and the Northern Territory remains under state and territory jurisdiction. Jurisdictional regulators continue to administer determinations made before 1 January 2008, except in Victoria, where the AER undertakes this role.[6] The AER is working with jurisdictional regulators and network businesses to maintain regulatory certainty in the transition period.

6.3.1 Regulatory process

Chapter 6 of the Electricity Rules sets out the timelines and processes for the economic regulation of distribution businesses. Distribution network businesses must periodically apply to the AER to determine their total revenue requirements for periods of at least five years. The regulatory process is lengthy to allow time for stakeholder consultation and the engagement of specialist consultants.

The process begins when the AER publishes a draft framework and approach paper for a network 24 months before the start of the next regulatory period. The paper is finalised in consultation with stakeholders six months after the draft paper is published. The AER first applied this process to the South Australian and Queensland networks in 2008.[7]

The framework and approach process acknowledges differences in the regulation of each network. This partly reflects historical differences in regulatory approach across the jurisdictions. In the transition to national regulation, it is important to clarify these differences upfront and indicate how the AER will approach each determination. The process also enhances transparency and certainty by giving stakeholders an opportunity to understand and comment on the regulatory approach.

The framework and approach process clarifies high level regulatory mechanisms and aims to assist network businesses to prepare their proposals. While the process sets out the AER's thinking at the time, there is scope for the AER to modify its position on some mechanisms. In summary, of the positions developed through the framework and approach process:

- the control mechanism for setting a network's revenues or prices remains binding
- the classification of services remains binding unless the AER considers there are good reasons to change it
- all other positions are not binding.

Once the framework and approach process is completed, the network business must submit a regulatory proposal and a negotiation framework. This must occur at least 13 months before the end of the current regulatory period. The AER then assesses the proposal, typically with help from specialist consultants, and releases a draft determination for further consultation. It must release a final determination two months before the beginning of the upcoming regulatory period.

6 This administration of determinations after they have been made involves assessing pass-through applications, approving prices, and assessing and reporting performance. State and territory regulators can elect to transfer the administration of current determinations to the AER. In Victoria, several of these functions have been transferred, and the AER will administer the Electricity Distribution Price Determination applicable until 31 December 2010. In other states and territories, jurisdictional regulators will continue to administer current determinations.

7 The New South Wales and ACT distribution determinations were developed under transitional Electricity Rules, which did not provide for a framework and approach process.

Box 6.1 New South Wales and ACT distribution determinations

In April 2009 the AER released its first determinations for the distribution sector—for the New South Wales and ACT networks. The determinations provide for, in real terms, $13 billion of capital expenditure across the three New South Wales networks and $270 million for the ACT network over the period 2009–10 to 2013–14. The allowances are around 70 per cent higher than capital expenditure for the preceding five years.

The justification for higher investment varied across the networks but included:

- network augmentations to meet rising peak demand across the networks and significant load growth in regions including the north coast, the Sydney central business district and western Sydney
- the need to meet enhanced licensing conditions for network security and reliability
- the replacement of ageing and obsolete assets.

The AER also approved significantly higher allowances for operating and maintenance expenditure—over $6.5 billion for the regulatory period across the four businesses. This reflects assessments of prudent expenditure requirements for the networks.

The overall revenue allowance across the four businesses is almost $19 billion, around 60 per cent higher than for the previous regulatory period (in real terms). While this is a considerable increase, the allowances are lower than those sought by the businesses and those foreshadowed in the AER's draft report. This decision reflects revised economic forecasts (factoring in the effect of the global financial crisis) of easing demand growth.

The determinations will result in an increase in average residential electricity bills of up to $1.50 per week in 2009–10.

The New South Wales distribution businesses lodged appeals with the Australian Competition Tribunal over aspects of the decisions. The appeals may result in amendments to the determinations.

Figure 6.3
Determination processes for electricity distribution networks

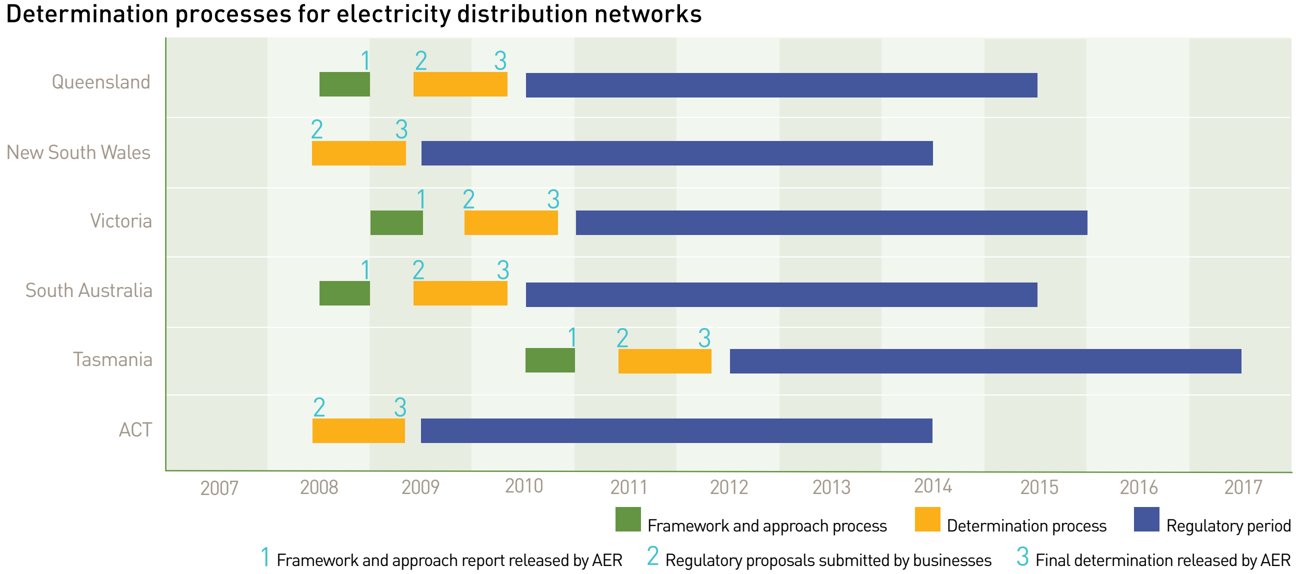


Figure 6.3 shows the regulatory timelines for each network. The AER completed its first electricity distribution reviews, for businesses in New South Wales and the ACT, in April 2009 (box 6.1). It has started work on determinations for the Queensland and South Australian networks, following the submission of regulatory proposals to the AER in June 2009. This process will determine each business's annual revenue requirements for the five year period from 1 July 2010.

For the Victorian networks, the next determinations are due to take effect on 1 January 2011. The AER has completed the framework and approach process and will complete the formal review process in late 2010.

6.3.2 Regulatory approach

The AER's regulatory approach involves setting a ceiling on the revenues or prices that a distribution business can earn or charge during a period, typically five years. The Electricity Rules require the use of incentives to optimise performance, but allow the regulator to choose the form of incentive. Regulatory frameworks currently used in Australia include revenue yield models (which control the average revenue per unit sold, based on volumes or revenue drivers) and weighted average price caps (which allow flexibility in individual tariffs within an overall ceiling).[8] Table 6.2 illustrates the range of available approaches.

Table 6.2 Control mechanisms available to electricity distribution businesses

FORM OF REGULATION	HOW IT WORKS	REGULATORY POSITION AT 1 JULY 2009	
		REGULATOR	DISTRIBUTION BUSINESSES
Price cap or tariff basket	Sets a ceiling on distribution tariffs/prices. For a weighted average price cap, the business is free to adjust its individual tariffs as long as the weighted average remains within the ceiling.	Essential Services Commission (Vic), administered by the AER	Powercor SP AusNet United Energy CitiPower Jemena
	There is no cap on the total revenue that a distribution business may earn. Revenues can vary depending on tariff structures and the volume of electricity sales.	AER	EnergyAustralia Integral Energy Country Energy
Revenue cap	Sets the maximum revenue that a business may earn during a regulatory period. It effectively caps total earnings. This mirrors the approach used to regulate transmission networks. The distribution business may set individual tariffs such that total revenues do not exceed the cap.	Queensland Competition Authority	ENERGEX Ergon Energy
		Office of the Tasmanian Economic Regulator	Aurora Energy
		Economic Regulation Authority (WA)	Western Power
Maximum average revenue cap	Sets a ceiling on average revenues during a regulatory period. Total prescribed distribution service revenues are capped each year at the average revenue allowance for a year multiplied by actual energy sales. Tariffs must be set to comply with this constraint.	AER	ActewAGL
Revenue yield control	Links the amount of revenue that a business may earn to the volume of electricity sold. Total revenues are not capped and may vary in proportion to the volume of electricity sales. The business is free to determine individual tariffs—subject to tariff principles and side constraints—such that total revenues do not exceed the average.	Essential Services Commission of South Australia	ETSA Utilities
Schedule of fixed prices	Sets a list or schedule of prices for each individual service provided by the distribution business.		

8 Some mechanisms are reflected only in past determinations by jurisdictional regulators.

As noted in table 6.2, the regulatory approach varies across networks. The AER's April 2009 determinations applied a weighted average price cap (which places a ceiling on the prices of distribution services during a regulatory period) to the New South Wales networks, and an average revenue cap (which sets a ceiling on revenue yields that may be recovered during a regulatory period) to the ACT network.

Recent AER framework and approach papers determined that the South Australian and Victorian networks will be subject to a weighted average price cap. The Queensland networks will be subject to a revenue cap. The AER has consulted with the relevant business to settle on these approaches.

In applying any of the forms of regulation in table 6.2, the AER must forecast the revenue requirement of a business over the regulatory period. To do this, it uses a building block model that factors in:

- investment forecasts (capital expenditure)
- the operating expenditure allowances that a benchmark distribution business would require if operating efficiently
- asset depreciation costs
- a commercial return on capital
- taxation liabilities.

In setting these elements, the AER has regard to demand projections, price stability, the potential for efficiency gains in cost and capital expenditure management, service standards and other factors. While jurisdictional regulators have taken varying approaches to specific building block components, the AER has developed a consistent method for all future revenue determinations.

Since assuming responsibility for the economic regulation of distribution networks, the AER has published models and guidelines to assist stakeholders. These include:

- a post-tax revenue model, which takes the cost estimates (or building blocks) for a network and determines the annual revenue requirement needed in each year of the regulatory period
- a roll-forward model, which determines a network's opening regulated asset base (RAB), taking account of capital expenditure, asset disposal and depreciation over the previous regulatory period. The model also establishes annual RAB forecasts for the coming regulatory period.
- a decision on the parameters of the weighted average cost of capital (WACC) model, which determines the return on capital that a regulated network may recover.[9] The WACC model sets an efficient benchmark for elements including equity raising and debt costs faced by a business when raising finance. The WACC model applies to all distribution businesses that submit regulatory proposals after 1 May 2009.
- cost allocation guidelines, which outline the cost allocation method for a network and the basis on which the AER will assess that method
- an issues paper on annual regulatory reporting requirements, with a view to publishing a regulatory information order in 2009. The order will set out guidance and protocols for the annual collection and submission of information to the AER for comparative analysis.

The AER has also developed incentive schemes to apply to distribution businesses:

- A *national efficiency benefit sharing scheme* provides incentives for distribution businesses to achieve efficient operating and maintenance expenditure in running their networks. The scheme shares efficiency gains between the business and customers (through lower prices). The AER indicated in its framework and approach papers that it will apply the scheme to businesses in Queensland, South Australia and Victoria from the next regulatory control period (see also section 6.5.3).

9 AER, *Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, final decision*, Melbourne, May 2009.

- A *national incentive scheme on service target performance* provides incentives for businesses to maintain or improve service performance across the network. It acts as a counterbalance to the efficiency benefit sharing scheme so businesses do not reduce costs at the expense of service quality. The scheme focuses on supply reliability (the frequency and duration of network outages) and customer service. If service performance falls below target, a business is penalised; if performance is above target, the business earns rewards. The scheme also includes a guaranteed service level (GSL) component, under which payments are made directly to customers when service performance falls below threshold levels. The service standards scheme applies as a paper trial in New South Wales and the ACT in the current regulatory period (that is, targets will be set but no financial penalties or rewards will apply). The AER indicated in its framework and approach papers that it will apply the service performance scheme to the Queensland, South Australian and Victorian networks in the next regulatory period (see also section 6.6.2).
- *Jurisdictional demand management incentive schemes* provide incentives for network businesses to implement efficient non-network approaches to manage demand. The schemes offer allowances for projects or initiatives that reduce network demand. In some jurisdictions, the schemes allow businesses to recover revenue that has been forgone due to successful demand reduction initiatives. No business is compelled to take up the scheme, with the allowance provided on a 'use it or lose it' basis. The AER has developed individual demand management schemes for New South Wales and the ACT, South Australia and Queensland, and Victoria (see also section 6.8.1).

6.4 Distribution investment

New investment in distribution infrastructure is needed to maintain and, where appropriate, improve network performance over time. Investment covers network augmentations to meet rising demand and expand into new regional centres and towns. It also covers upgrades to improve the quality of existing networks by replacing ageing assets. Some investment is driven by regulatory requirements on matters such as network reliability.

Figure 6.4 shows the opening RABs and forecast regulated investment over the current regulatory period for the major networks.[10] The combined opening RABs of distribution networks are around $39 billion, more than double the valuation for transmission infrastructure. Investment over the current regulatory cycle for the networks is forecast at around $25 billion.[11]

Many factors can affect the value of RABs and investment, including the basis of original valuation, historical network investment, the age of a network, geographic scale, the distances required to transport electricity from transmission connection points to demand centres, population dispersion and forecast demand profiles.

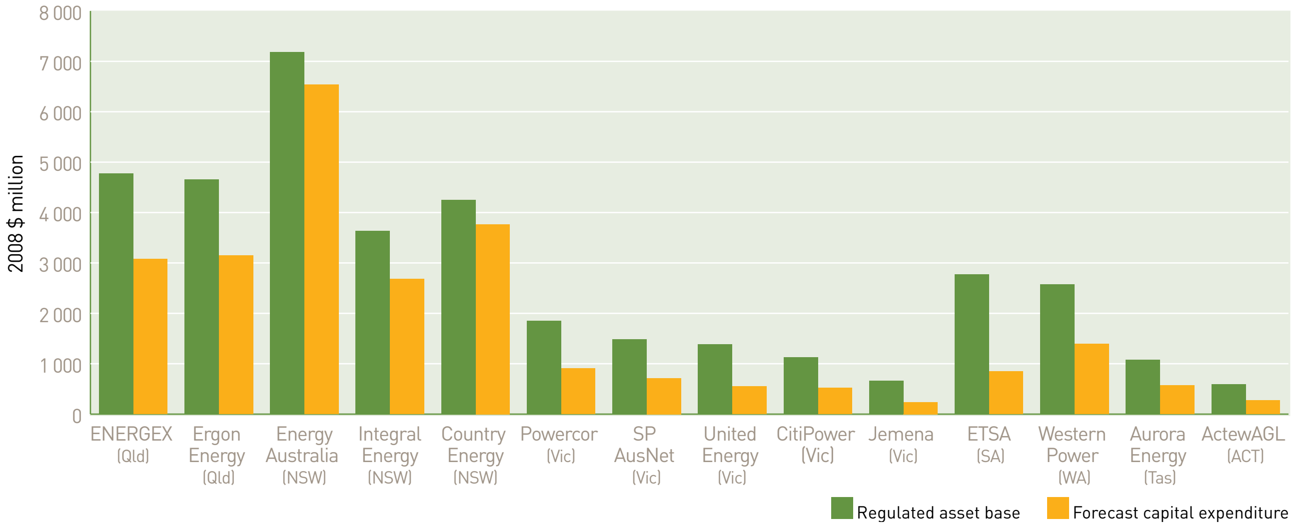
Figure 6.5 charts annual investment in regulated assets in each network, using actual data where available and forecast data for other years. The forecast data relate to proposed investment that the regulator has approved as efficient at the beginning of the regulatory period. The forecast data are smoothed over the regulatory period to remove the significant volatility often evident in the annual forecast data. The charts depict real data in June 2008 dollars.

10 Regulated investment in most networks does not include capital contributions. Although this expenditure forms part of the overall investment in a network, the distribution business does not incur the development costs and, accordingly, does not receive a return on those assets. At the end of the regulatory period, the RAB is adjusted to reflect new regulated investment that has occurred.

11 Investment estimates are for the current (typically five year) regulatory periods. The RAB and investment values are in June 2008 dollars.

Figure 6.4

Electricity distribution network assets and investment—current regulatory period



Notes:

The regulated asset base is the opening asset valuation for the current regulatory period. Forecast capital expenditure is for the current regulatory period.

The regulatory period is 4.5 years for Aurora Energy (Tas), three years for Western Power (WA) and five years for other networks.

Data for Western Power are from the ERA's draft decision on proposed revisions to Western Power's access arrangement for the period 2009–10 to 2011–12.

All values are converted to June 2008 dollars.

Sources: Regulatory determinations published by the AER (NSW and ACT), the ESC (Vic), the QCA (Qld), ESCOSA (SA), OTTER (Tas) and the ERA (WA).

In summary, investment in the NEM jurisdictions was forecast at over $4.1 billion in 2008–09, increasing to almost $4.8 billion in 2009–10. In Western Australia, $380 million of investment was forecast in 2008–09, with the Economic Regulation Authority proposing investment by Western Power of $450 million in 2009–10. Investment has risen steadily during the current decade in most networks. This has generally been accompanied by stable reliability outcomes.[12]

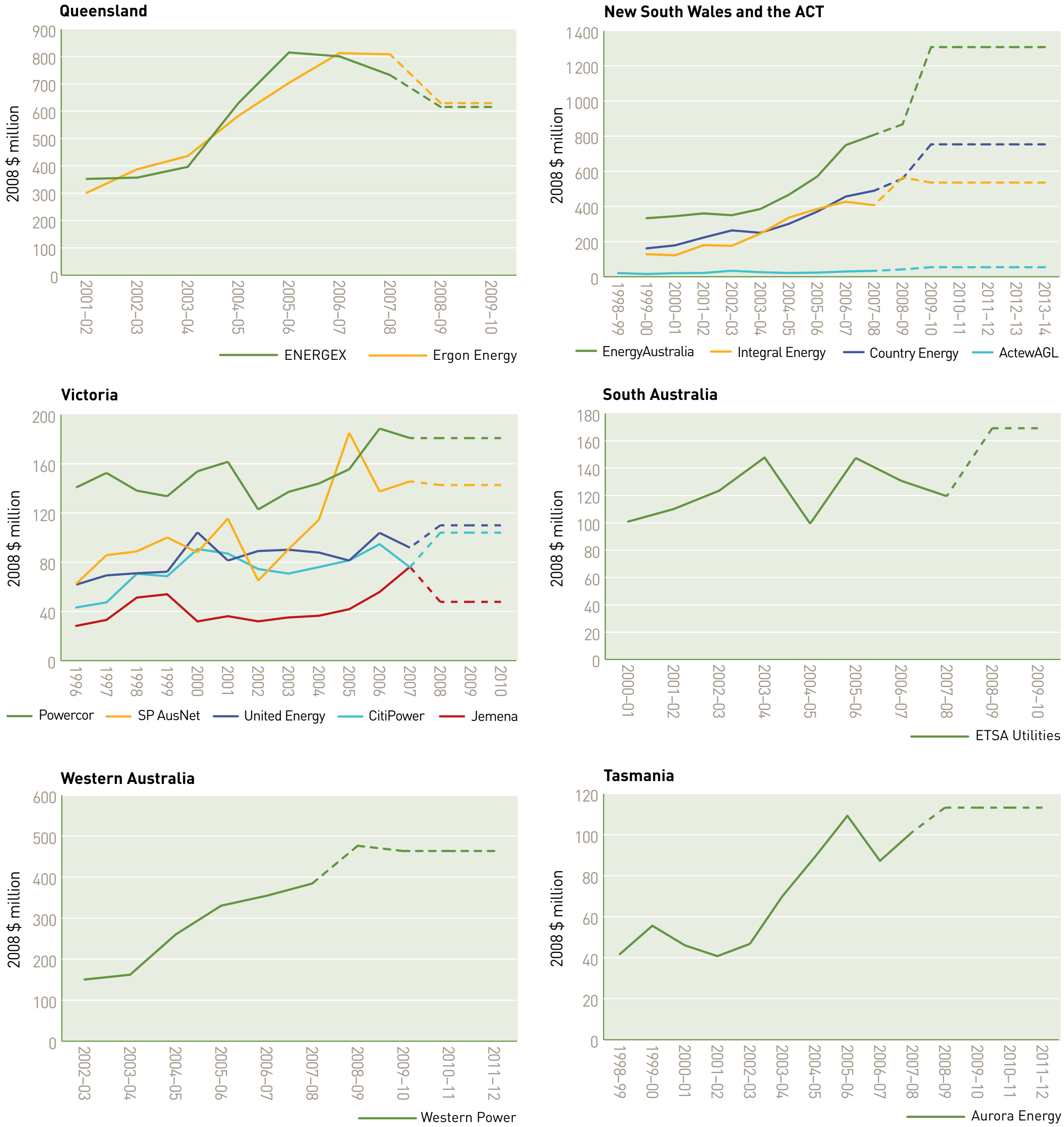
On average, investment during the current regulatory cycle is running at over 40 per cent of the underlying asset base in most networks, over 65 per cent in Queensland and up to 90 per cent in parts of New South Wales. Different outcomes across jurisdictions reflect a range of variables, including forecast demand, the scale and age of the networks, and investment allowances in historical regulatory determinations.

Box 6.1 includes a summary of the New South Wales and ACT distribution determinations released by the AER for the period 2009–10 to 2013–14.

There is some volatility in the investment data, reflecting a number of factors. In particular, investment is somewhat lumpy as a result of the one-off nature of some capital programs. More generally, the network businesses have some flexibility in managing and reprioritising their capital expenditure over the regulatory period. Transitions between regulatory periods, and from actual to forecast data, also result in some data volatility—for example, network businesses tend to schedule a significant portion of investment in the early stages of a regulatory period, although some projects may be subsequently delayed.

12 See section 6.6 and figure 6.10.

Figure 6.5
Electricity distribution network investment



Notes:

Actual data (unbroken lines) used where available and forecasts (broken lines) for other years as set out in regulatory determinations (except for Western Australia, for which forecasts for 2009–10 to 2011–12 are based on the ERA's draft decision for Western Power). Forecasts are of average capital expenditure over the regulatory period.

All data have been converted to June 2008 dollars.

Sources: Regulatory determinations published by the AER (NSW and the ACT), the ESC (Vic), the QCA (Qld), ESCOSA (SA), the ERA (WA) and OTTER (Tas).

In addition to regulated investment undertaken by the distribution businesses, market participants can also fund new investment in the networks. These capital contributions can form a significant proportion of new network investment—for example, they have typically accounted for over 15 per cent of total distribution network investment in Victoria and over 25 per cent of investment in South Australia.

For most distribution businesses, investment funded through capital contributions sits outside the RAB and the businesses do not earn a return on the assets. In Queensland and Western Australia, however, distribution businesses have capital contributions included in the RAB. The revenue allowance of these businesses is adjusted to ensure overall returns reflect the actual business activity of the network.[13]

6.5 Financial performance of distribution networks

Financial data on distribution networks are available from two main sources—performance reports and regulatory determinations. Until recently, all jurisdictional regulators published annual reports on electricity distribution networks, covering financial and service performance.

With the move to national regulation in 2008, the AER will play a role in public reporting on the financial performance of the networks. Initial reports will be prepared for the Victorian networks for the 2009 reporting year, and for the New South Wales and ACT networks for 2009–10. The AER will consult with stakeholders to develop an appropriate reporting framework.

Regulatory determinations include historical financial data for the preceding regulatory period and forecast outcomes.

6.5.1 Revenues

Figure 6.6 charts revenues for distribution networks, based on actual results where available and otherwise using regulatory forecasts. Allowed revenues are tending to rise over time as underlying asset bases expand to meet rising demand. The combined revenue of the NEM's 13 major distribution networks was forecast at around $6.1 billion in 2008–09, a rise of about 4 per cent in real terms over the previous year. A further rise of about 12 per cent in real terms ($6.8 billion) is forecast for 2009–10.

In Western Australia, Western Power's allowed revenues in 2008–09 were around $400 million. It has proposed an increase to over $600 million in 2009–10.

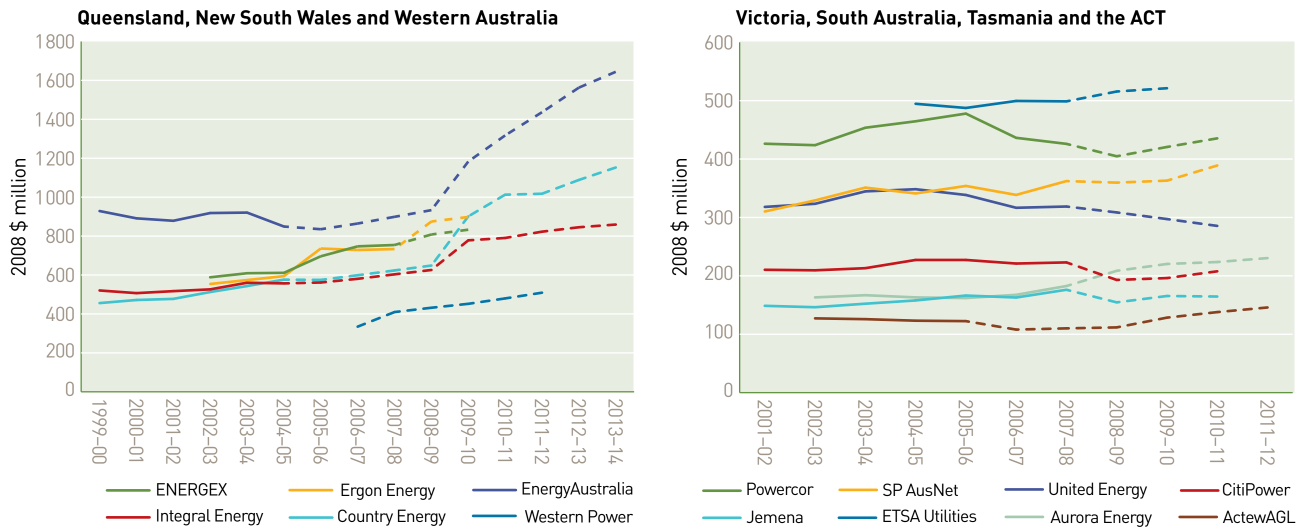
6.5.2 Return on assets

A common financial indicator for a business is its return on assets. The ratio is calculated as operating profits (net profit before interest and taxation) as a percentage of the average RAB. Figure 6.7 sets out the returns on assets for distribution businesses in the NEM, where data are available. Over the past seven years, the privately owned businesses in Victoria and South Australia tended to yield returns of about 8–12 per cent. Returns for these businesses were consistently higher than regulatory forecasts of 7–9 per cent. The government owned distribution businesses in New South Wales, Queensland and Tasmania achieved returns ranging from 4 per cent to 10 per cent.

A variety of factors can affect performance in this area. These include differences in the demand and cost environments faced by each business, and variances in demand and costs outcomes compared with those forecast in the regulatory process.

13 Western Power has proposed, for the regulatory period 2009–10 to 2011–12, that capital contributions be excluded from the RAB.

Figure 6.6
Electricity distribution network revenues



Notes:

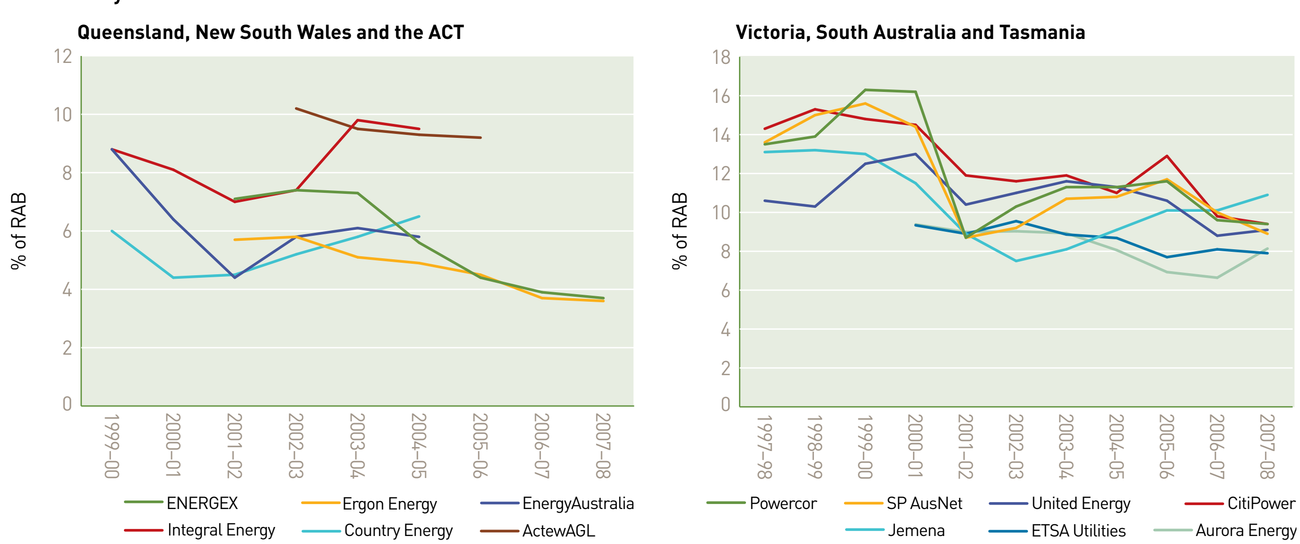
Actual data (unbroken lines) used where available and forecasts (broken lines) for other years as provided in regulatory determinations (except for Western Australia, for which forecasts for 2009–10 to 2011–12 are based on the ERA's draft decision).

Data are for year ended 30 June. Victorian data are for the calendar year ending in that period.

All data have been converted to June 2008 dollars.

Sources: Regulatory determinations published by the AER (NSW and the ACT), the QCA (Qld), IPART (NSW), the ESC (Vic), ESCOSA (SA), the ERA (WA), OTTER (Tas) and the ICRC (ACT).

Figure 6.7
Electricity distribution network return on assets

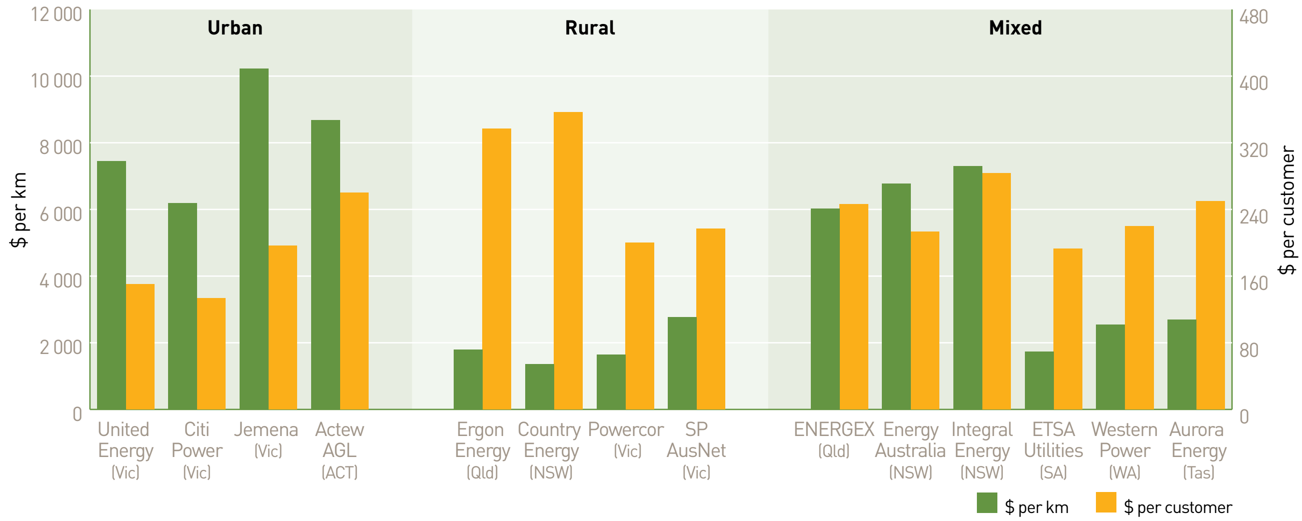


RAB, regulated asset base.

Note: Data are for year ended 30 June. Victorian data are for the calendar year ending in that period.

Sources: Performance reports published by the ESC (Vic), IPART (NSW), the QCA (Qld), ESCOSA (SA), OTTER (Tas) and the ICRC (ACT).

Figure 6.8
Forecast operating and maintenance expenditure—electricity distribution networks, 2008–09



Note: Forecast data for 2008–09 are converted to June 2008 dollars. Victorian data are for the calendar year 2008.

Sources: Regulatory determinations published by the ESC (Vic), IPART (NSW), the QCA (Qld), ESCOSA (SA), the ERA (WA), OTTER (Tas) and the ICRC (ACT).

6.5.3 Operating and maintenance expenditure

Figure 6.8 charts forecast operating and maintenance expenditure for each network on per kilometre and per customer bases in 2008–09. The forecasts reflect regulatory allowances for each network to cover efficient operating and maintenance expenditure. There is a range of outcomes in this area, reflecting differences in customer and load densities, the scale and condition of the networks, geographic factors and reliability requirements. Normalising on a per kilometre basis tends to bias against high density urban networks with relatively short line lengths—reflected in the high outcomes for the three Victorian urban networks and the ACT network—while normalising on a per customer basis tends to bias against low density rural networks such as the Ergon Energy and Country Energy networks.

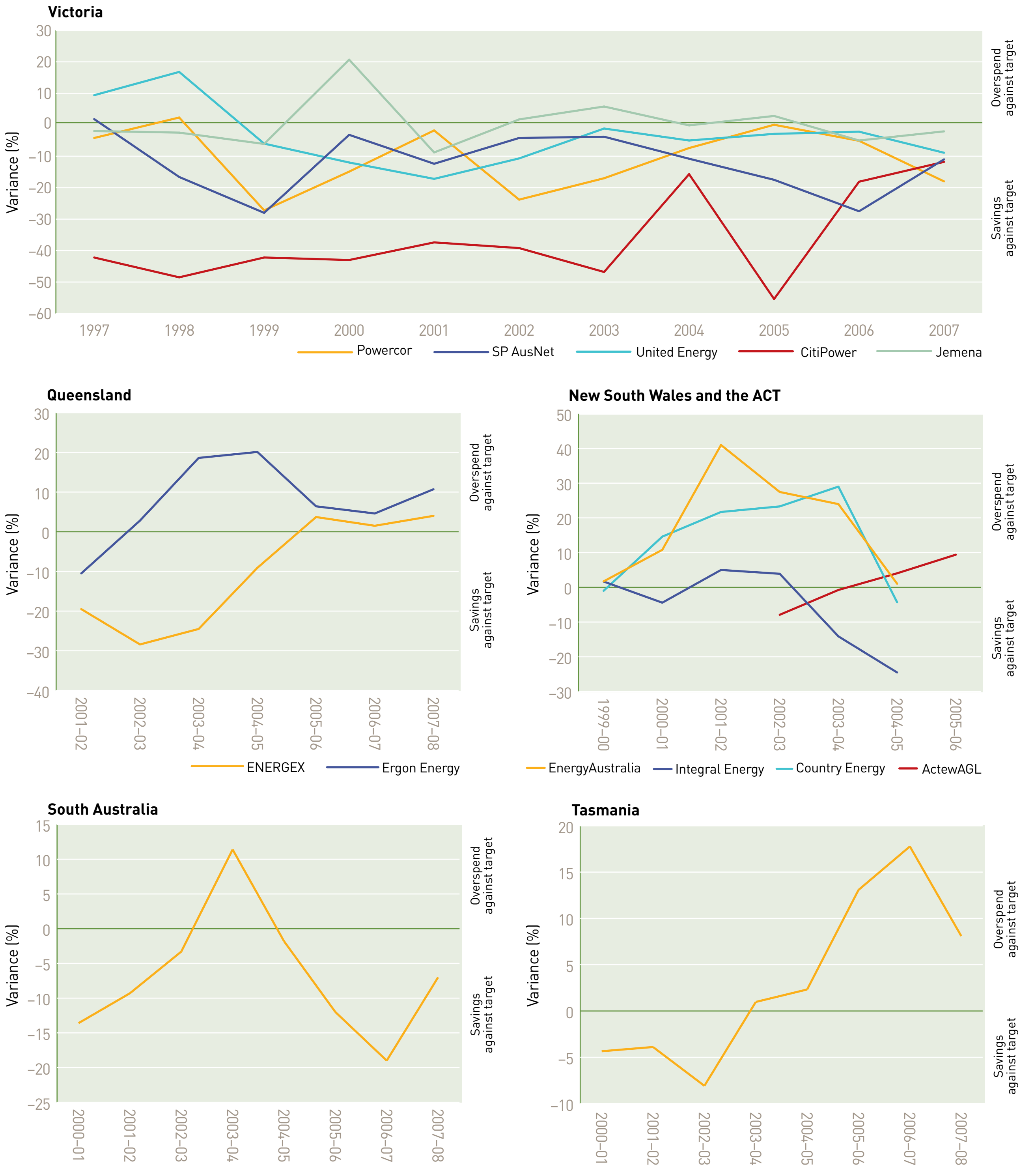
The AER published details in June 2008 of an efficiency benefit sharing scheme as part of the national framework for distribution regulation.[14] The scheme provides incentives for businesses to reduce their spending against benchmarks through efficient operating practices. It applies uniformly to all distribution businesses. The AER will first apply the scheme to the Queensland and South Australian networks from July 2010.

The scheme provides incentives for a distribution business to make efficient expenditure, by allowing it to retain efficiency gains for five years after a gain is made. A benchmark level of expenditure is used to determine revenue adjustments. Under the national scheme, the distribution business retains 30 per cent of efficiency gains against the benchmark, with the remaining 70 per cent being returned to customers through lower prices.

14 AER, *Electricity distribution network service providers: efficiency benefit sharing scheme, final decision*, Melbourne, June 2008.

Figure 6.9

Operating and maintenance expenses of electricity distribution networks—variances from target



Sources: Performance reports published by the ESC (Vic), IPART (NSW), the QCA (Qld), ESCOSA (SA), OTTER (Tas) and the ICRC (ACT).

Over time, the national scheme will replace the current state based incentive schemes that jurisdictional regulators administer in the NEM. Figure 6.9 compares actual expenditure against target expenditure for each network under the state based schemes. A positive variance indicates that actual expenditure exceeded the benchmark in that year—that is, the distribution business overspent. A negative variance indicates underspending against the benchmark. A trend of negative variances over time may suggest a positive response to efficiency incentives. More generally, care should be taken in interpreting year-to-year changes in operating expenditure. The network businesses have some flexibility in managing their expenditure over the regulatory period, so timing considerations may affect the data. Delays in completing a project may also affect expenditure.

Figure 6.9 indicates that the South Australian network and most Victorian networks underspent against their forecast allowances for most or all of the charted period. The Queensland networks recorded small but consistent overspends of up to 10 per cent from 2005–06. The Tasmanian network consistently overspent from 2003–04.

6.6 Service quality and reliability

Electricity distribution networks are monopolies that face little risk of losing customers if they provide poor service. In addition, regulatory incentive schemes for efficient cost management might encourage a business to sacrifice service performance to reduce costs. Recognising these risks, governments and regulators monitor the performance of distribution businesses to ensure they provide acceptable levels of service.

Quality of service monitoring for electricity distribution typically relates to:

- reliability (the continuity of electricity supply through the network)
- technical quality (for example, voltage stability)
- customer service (for example, on-time provision of services and the adequacy of call centre performance).

All jurisdictions regulate the service performance of distribution networks through:

- the monitoring and reporting of reliability, technical quality and customer service outcomes against standards set in legislation, regulations, licences and codes (possibly with sanctions for non-compliance)
- GSLs (relating to network reliability, technical quality of service and customer service) that require, if not met, a network business to pay affected customers.

The legislated service standards are designed to ensure distribution businesses maintain appropriate levels of performance. GSL schemes ensure distribution businesses do not have an incentive to neglect regions or individual customers within their network.
In addition to these measures, some jurisdictions have applied financial incentive schemes for distribution businesses to maintain and improve service performance over time. With the shift to national distribution regulation, the AER published in 2009 details of a national service target performance incentive scheme that will apply, over time, to all distribution networks.

In the future, the AER will publicly report on the service performance of distribution businesses. It will consult with stakeholders on the reporting measures and future reporting arrangements.

6.6.1 Reliability

Reliability refers to the continuity of electricity supply to customers, and it is a key service performance indicator. Distribution outages account for over 90 per cent of the duration of all electricity outages in the NEM. Relatively few outages originate in the generation and transmission sectors.[15]

A reliable distribution network keeps interruptions or outages in the transport of electricity down to efficient levels. It would be inefficient to try to eliminate every possible interruption. Rather, an efficient outcome requires assessing the value of reliability to the community (measuring the impact on services) and the willingness of customers to pay. There has been some research on the willingness of electricity customers to pay higher prices for a reliable electricity supply. A 1999 Victorian study found more than 50 per cent of customers were willing to pay a higher price to improve or maintain their level of supply reliability.[16] However, South Australian surveys in 2003 and 2007 indicated few customers were willing to pay for improvements in service. The 2007 survey found only 13 per cent of customers were willing to pay more for service improvement, with no significant difference in response between those experiencing high and low reliability.[17]

Surveys of consumer preferences do not necessarily capture all benefits from improved supply reliability, particularly those benefits from avoiding disruption to essential services. In a review of minimum service standards and GSLs in Queensland, Evans & Peck concluded, considering all impacts, that customers as a community value improved reliability.[18]

Various factors, both planned and unplanned, can impede network reliability:

> A planned interruption occurs when a distributor needs to disconnect supply to undertake maintenance or construction works. Such interruptions can be timed for minimal impact.

> Unplanned outages occur when equipment failure causes the supply of electricity to be unexpectedly disconnected. They may result from operational error, asset overload or deterioration, or routine external causes such as damage caused by trees, birds, possums, vehicle impacts or vandalism. Networks can also be vulnerable to extreme weather, such as bushfires or storms. There may be ongoing reliability issues if part of a network has inadequate maintenance or is used near its capacity limits at times of peak demand. These factors sometimes occur in combination.

The impact of a distribution outage tends to be localised to a part of the network and depends on customer load, the design of the network and the time taken by a distributor to restore supply after an interruption. Maintenance practices are an important factor in reducing the number of outages and the time it takes to reconnect supply. Distribution businesses undertake large maintenance programs that include asset inspections and repairs, vegetation clearing and emergency response.

Jurisdictions track the reliability of distribution networks against performance standards to assess whether it is satisfactory. The standards account for the trade-off between improved reliability and cost. Ultimately, customers must pay for the cost of investment, maintenance and other solutions needed to deliver a reliable power system.

The trade-offs between improved reliability and cost have resulted in standards for distribution networks being less stringent than for generation and transmission.

15 See AER, *State of the energy market 2007, essay B*, Melbourne, 2007, pp. 38–53.

16 KBA and Powercor, *Understanding customers' willingness to pay: components of customer value in electricity supply*, Melbourne, 1999.

17 The 2003 survey found a willingness to pay for improvements in service only to poorly served consumers. On this basis, ESCOSA has focused on providing incentives to improve the reliability performance for the 15 per cent of worst served consumers, while maintaining average reliability levels for all other customers. See ESCOSA, *2005–2010 Electricity distribution price determination, part A*, Adelaide, April 2005; KPMG, *Consumer preferences for electricity service standards*, Adelaide, March 2003; and McGregor Tan Research, *Consumer preferences for electricity service standards*, Adelaide, November 2007.

18 Evans & Peck, *Queensland Competition Authority, Review of minimum service standards and guaranteed service levels*, Brisbane, December 2008, p. 49.

These less stringent standards also reflect the localised effects of distribution outages, compared with the potentially widespread geographic impact of a generation or transmission outage. The capital intensive nature of distribution networks makes it very expensive to build in high levels of redundancy (spare capacity) to improve reliability. These factors help to explain why distribution outages account for such a high proportion of electricity outages in the NEM.

For similar reasons, there tend to be different reliability standards for different feeders (parts) of a distribution network. A higher reliability standard is usually required, for example, for a central business district (CBD) network with a large customer base and a concentrated load density than for a highly dispersed rural network with a small customer base and a low load density. While the unit costs of improving reliability in a dispersed rural network are relatively high, an outage is likely to affect few customers. Conversely, the unit costs of improving reliability in a high density urban network are relatively low, and an outage is likely to affect many customers.

Reliability data

All jurisdictions have their own monitoring and reporting frameworks for reliability. In addition, the Steering Committee on National Regulatory Reporting Requirements (SCONRRR)[19] has adopted four indicators of distribution network reliability that are widely used in Australia and overseas. The indicators relate to the average frequency and duration of network interruptions or outages (table 6.3). The indicators do not distinguish between the nature and size of loads affected by supply interruptions.

In most jurisdictions, distribution businesses report performance against the system average interruption duration index (SAIDI), the system average interruption frequency index (SAIFI) and the customer average interruption duration index (CAIDI) indicators. The national service performance incentive scheme, published in June 2008, includes the SAIDI and SAIFI indicators.[20]

Table 6.3 Reliability measures—electricity distribution

INDEX	NAME	DESCRIPTION
SAIDI	System average interruption duration index	Average total number of minutes that a customer is without electricity in a year (excludes interruptions of one minute or less)
SAIFI	System average interruption frequency index	Average number of times a customer's supply is interrupted per year
CAIDI	Customer average interruption duration index	Average duration of each interruption (minutes)
MAIFI	Momentary average interruption frequency index	Average number of momentary interruptions (of one minute or less) per customer per year

Source: URF, *National regulatory reporting for electricity distribution and retailing businesses*, Canberra, 2002.

Regulators audit, analyse and publish reliability outcomes, typically down to feeder level (CBD, urban and rural) for each network.[21] Tables 6.4 and 6.5 and figure 6.10 estimate historical SAIDI and SAIFI data for NEM jurisdictions. Some data from Western Australia are also provided. In the future, the AER will report on reliability outcomes as part of its performance reporting on the distribution sector.

The data in tables 6.4 and 6.5 and figure 6.10 reflect total outages experienced by distribution customers. In general, the data have not been normalised to exclude distribution outages that are beyond the reasonable control of the network operator—for example, outages that originate in the generation and transmission sectors, and outages caused by external factors such as extreme weather. The data for Queensland in 2005–06 and New South Wales in 2006–07, however, have been adjusted to remove the impact of natural disasters (Cyclone Larry in Queensland and extreme storm activity in New South Wales), which would otherwise severely distort the data.

19 SCONRRR is a working group established by the Utility Regulators Forum.

20 AER, *Electricity distribution network service providers: service target performance incentive scheme, final decision*, Melbourne, June 2008. See section 6.6.4.

21 In New South Wales, the distribution businesses publish these data in the first instance. The regulator (IPART) periodically publishes summary data.

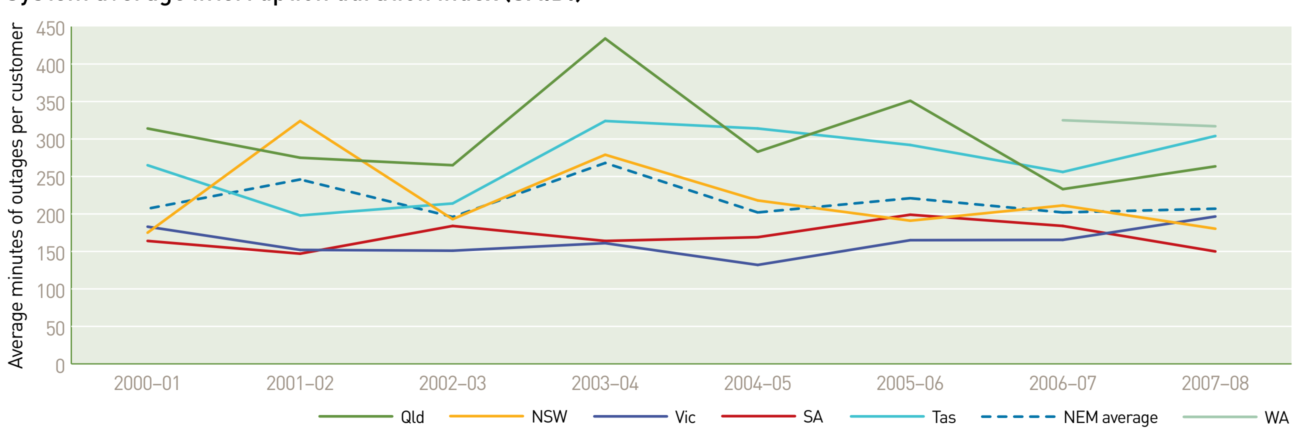
Table 6.4 System average interruption duration index (SAIDI) (minutes)

	2000–01	2001–02	2002–03	2003–04	2004–05	2005–06	2006–07	2007–08
Queensland	331	275	265	434	283	353	231	264
New South Wales	175	324	193	279	218	191	211	180
Victoria	183	152	151	161	132	165	165	197
South Australia	164	147	184	164	169	199	184	150
Tasmania	265	198	214	324	314	292	256	304
NEM weighted average	211	246	196	268	202	221	202	207
Western Australia							325	317

Table 6.5 System average interruption frequency index (SAIFI)

	2000–01	2001–02	2002–03	2003–04	2004–05	2005–06	2006–07	2007–08
Queensland	3.0	2.8	2.7	3.4	2.7	3.1	2.1	2.4
New South Wales	2.5	2.6	1.4	1.6	1.6	1.8	1.9	1.7
Victoria	2.1	2.0	2.0	2.2	1.9	1.8	1.9	2.1
South Australia	1.7	1.6	1.8	1.7	1.7	1.9	1.8	1.5
Tasmania	2.8	2.3	2.4	3.1	3.1	2.9	2.6	2.6
NEM weighted average	2.4	2.4	1.9	2.2	1.9	2.1	2.0	1.9
Western Australia							3.3	3.3

Figure 6.10
System average interruption duration index (SAIDI)



Notes for tables 6.4 and 6.5 and figure 6.10:

The data reflect total outages experienced by distribution customers. In some instances, the data may include outages resulting from issues in the generation and transmission sectors. In general, the data have not been normalised to exclude distribution network issues beyond the reasonable control of the network operator. The data for Queensland in 2005–06 and New South Wales in 2006–07 have been adjusted to remove the impact of natural disasters (Cyclone Larry in Queensland and extreme storm activity in New South Wales), which would otherwise have severely distorted the data.

The NEM averages are weighted by customer numbers.

Victorian data are for the calendar year ending in that period.

Sources for tables 6.4 and 6.5 and figure 6.10: Performance reports published by the ESC (Vic), IPART (NSW), the QCA (Qld), ESCOSA (SA), the ERA (WA), OTTER (Tas), the ICRC (ACT), EnergyAustralia, Integral Energy and Country Energy. Some data are AER estimates derived from official jurisdictional sources. The AER consulted with PB Associates in the development of historical data.

From a customer perspective, the unadjusted data presented here are relevant, but an assessment of distribution network performance should normalise data to exclude external sources of interruption. The SCONRRR agreed that reliability data should, in some circumstances, be normalised to exclude interruptions beyond the control of a network business.

Until recently, there was no consistent approach to determining exclusions.[22] Now, the AER national service target performance incentive scheme (published in May 2009) adopts a consistent approach to exclusions, based on a standard set by the Institute of Electrical and Electronics Engineers. The standard is used in a number of Australian jurisdictions. In addition, the scheme identifies events that should be excluded.[23] The impact of excluded events is considered later in this chapter.

A number of issues limit the validity of comparing performance across the networks. In particular, the data rely on the accuracy of the network businesses' information systems, which may vary considerably. There are also differences in design, geographic conditions and historical investment across the networks. As noted, differences in customer density and load density can affect the costs and benefits of achieving high reliability. More generally, each jurisdiction historically took a different approach to approving and reporting excluded events and, until recently, there has been no consistent approach to auditing performance outcomes.

Noting these caveats, the SAIDI data indicate that distribution networks in the NEM have delivered reasonably stable reliability outcomes over the past few years, with recent improvements in some jurisdictions. The NEM-wide SAIDI was generally 200–250 minutes from 2000–01 to 2007–08, but with significant regional variations.

The average duration of outages per customer has tended to be lower in Victoria and South Australia than elsewhere, despite some community concerns in the 1990s that privatisation might adversely affect service quality. Outage duration has tended to fall in New South Wales since 2003–04, and in 2007–08 that state recorded the second lowest outage rate behind South Australia. Average reliability (as measured by SAIDI) is weaker in Queensland and Tasmania than in other NEM jurisdictions. Queensland is subject to significant variations in performance, partly as a result of its large and widely dispersed rural networks, and extreme weather events. These characteristics make Queensland more vulnerable to outages than are some other jurisdictions, although it has recorded improvements in reliability since 2003–04. Data for Western Australia indicate that outage duration has recently been higher in that state than in the NEM jurisdictions.

The SAIFI data appear to show an improvement in the average frequency of outages across the NEM since 2000. The average frequency of outages is higher in Queensland than in other mainland jurisdictions, although that state's performance improved over 2006–07 and 2007–08. On average, distribution customers in the mainland NEM regions experience outages around twice a year. The rate has been a little higher in Tasmania. Western Australian customers experience outages around three times a year.

The recent improvements in reliability in New South Wales and Queensland are consistent with the rising investment trends noted in section 6.4. In Queensland, the government acted to improve reliability when a 2004 review (the Somerville review) found distribution service performance was unsatisfactory.[24] The government introduced performance requirements aimed at improving reliability by 25 per cent by 2010.

22 The SCONRRR definitions of SAIDI and SAIFI exclude outages that exceed a threshold SAIDI impact of 3 minutes; outages that are caused by exceptional natural or third party events; and outages for which the distribution business cannot reasonably be expected to mitigate the effect by prudent asset management.

23 AER, *Electricity distribution network service providers: service target performance incentive scheme, final decision*, Melbourne, May 2009, section 6.7.

24 For background on the Somerville review and Queensland's reliability issues, see AER, *State of the energy market 2007*, Melbourne, 2007, p. 53.

In New South Wales, licensing requirements relating to network design, reliability and performance have been gradually enhanced, requiring greater expenditure by the network businesses to ensure compliance.

Reliability of distribution networks by feeder

Given the diversity of network characteristics, it is often more meaningful to compare reliability by feeder category rather than across networks as a whole. There are four categories of feeder, based on geographic location (table 6.6).

Table 6.6 Feeder categories

FEEDER CATEGORY	DESCRIPTION
CBD	A feeder that predominately supplies commercial, high rise buildings through an underground distribution network containing significant interconnection and redundancy compared with urban areas
Urban	A feeder that is not a CBD feeder, with actual maximum demand over the reporting period per total feeder route length greater than 0.3 megavolt amperes per kilometre
Rural short	A feeder that is not a CBD or urban feeder, with a total feeder route length less than 200 kilometres
Rural long	A feeder that is not a CBD or urban feeder, with a total feeder route length greater than 200 kilometres

Source: URF, *National regulatory reporting for electricity distribution and retailing businesses*, Canberra, 2002.

Figures 6.11a–d set out the average duration of supply interruptions per customer (SAIDI) for each feeder type, subject to data availability. The charts distinguish between outages that are deemed within the reasonable control of the networks (normalised outages) and outages deemed beyond their control. The latter exclusions cover outages that originate in the generation and transmission sectors, and outages caused by external events such as extreme weather. Generally, it would be unreasonable to assess network performance unless excluding the impact of these external factors. Total network outages in a period are the sum of the normalised and excluded data.

Meaningful comparisons across jurisdictions—even based on the normalised data—are difficult given the differences in approach to exclusions and in auditing practices. Any attempt to compare performance should also account for geographic, environmental and other differences across the networks. That said, CBD and urban customers tend to experience better network reliability than rural customers.

The variations in performance across feeder types reflect that reliability standards account for the differing cost–benefit reliability trade-offs in each part of a network. To illustrate, a network outage on a CBD feeder is likely to have more severe economic consequences than from a similar outage on a remote rural feeder where customer bases and loads are more dispersed. Similarly, the unit costs of improving reliability in a high density urban network will be lower than in a dispersed rural network that is exposed to more variable weather and where it is more difficult to access lines to identify and repair faults. For these reasons, CBD networks are designed for higher reliability than other feeders are, and they use underground feeders, which are less vulnerable to outages.

Figure 6.11a

CBD feeders—average duration of supply interruptions per customer (SAIDI)

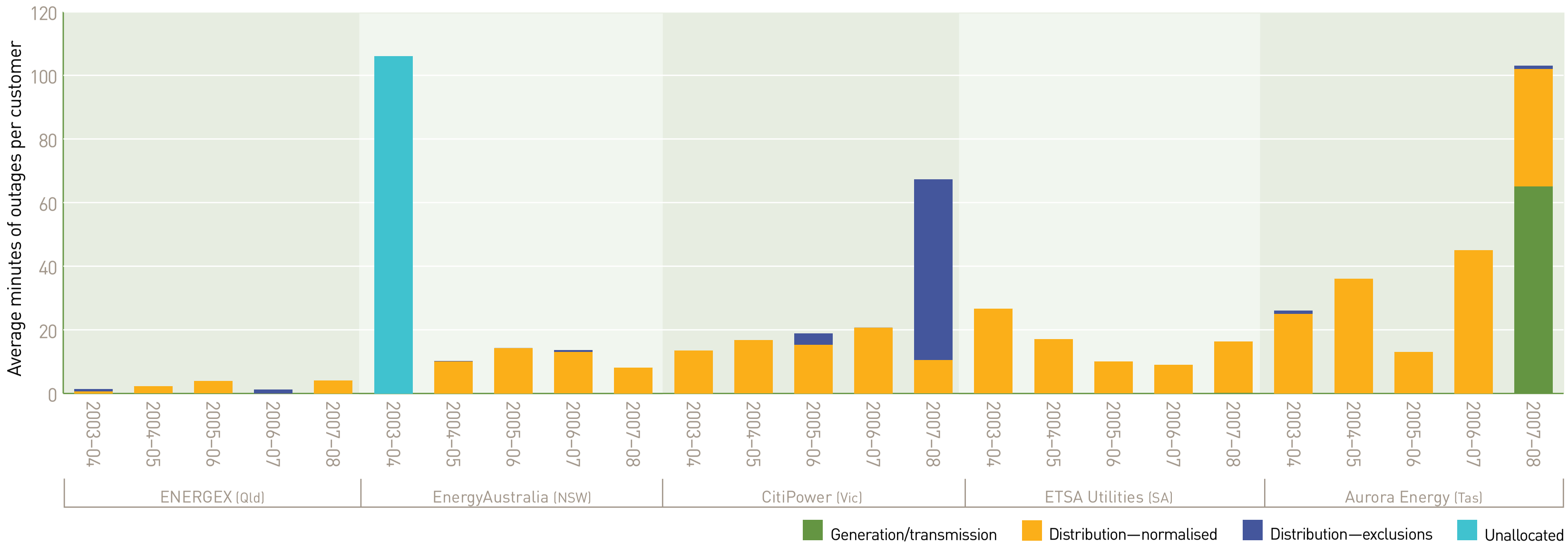


Figure 6.11b

Urban feeders—average duration of supply interruptions per customer (SAIDI)

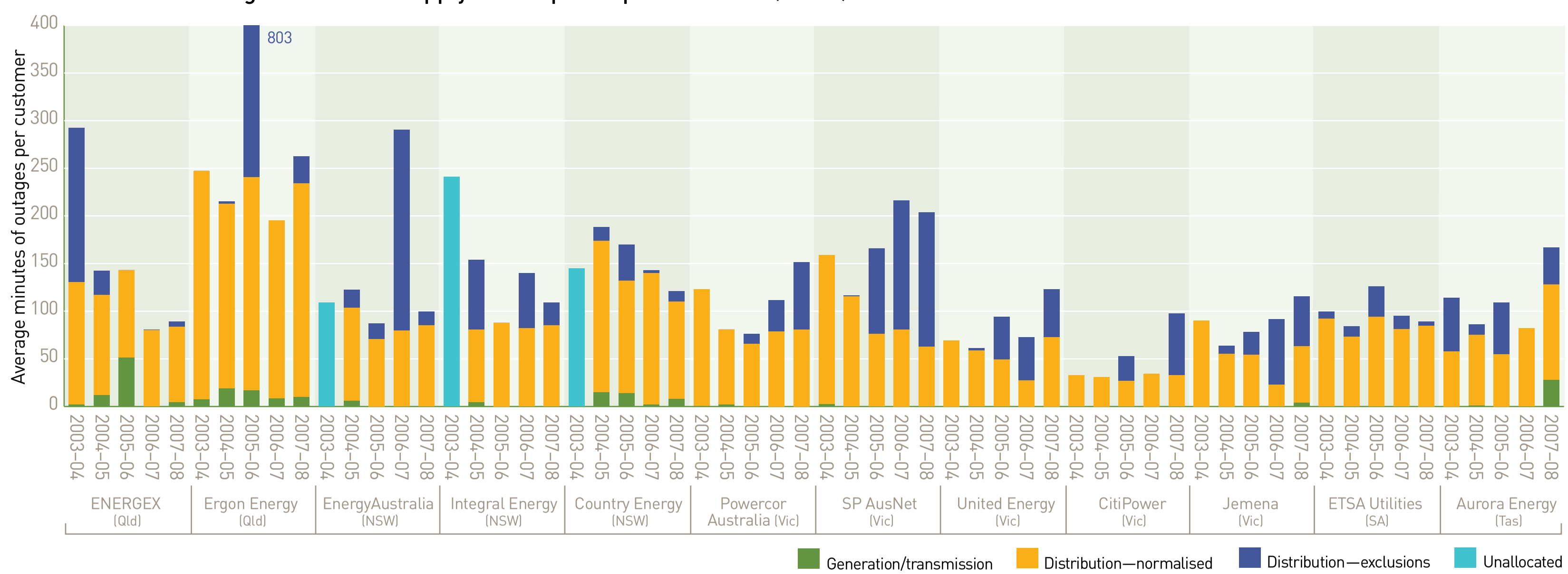


Figure 6.11c

Rural short feeders—average duration of supply interruptions per customer (SAIDI)

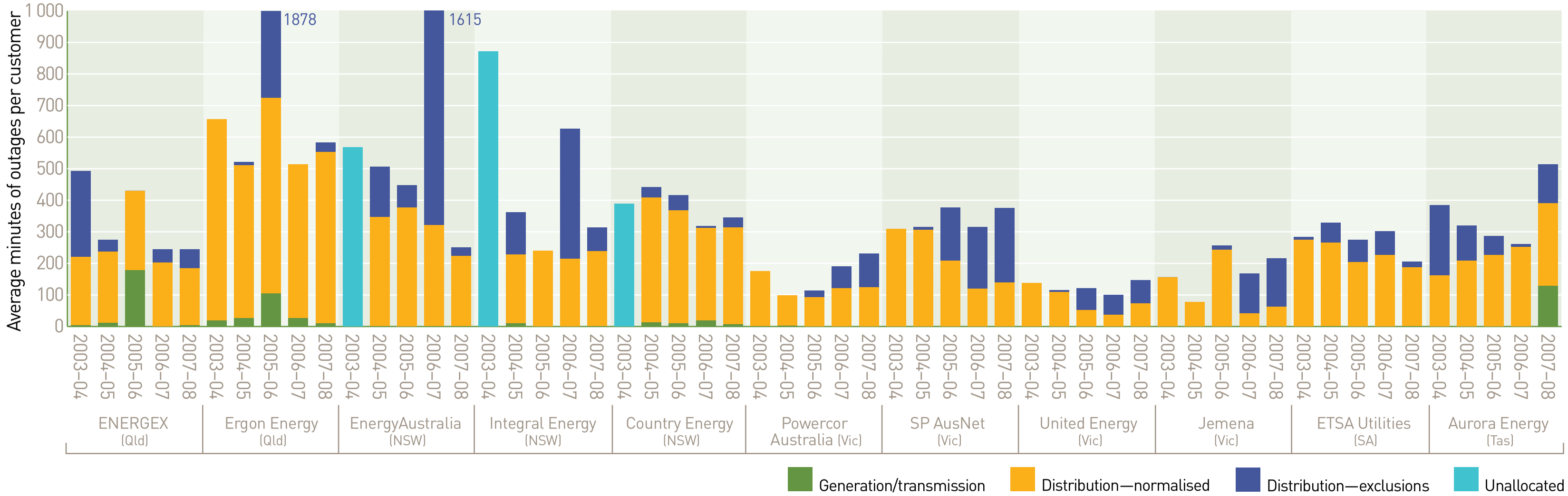
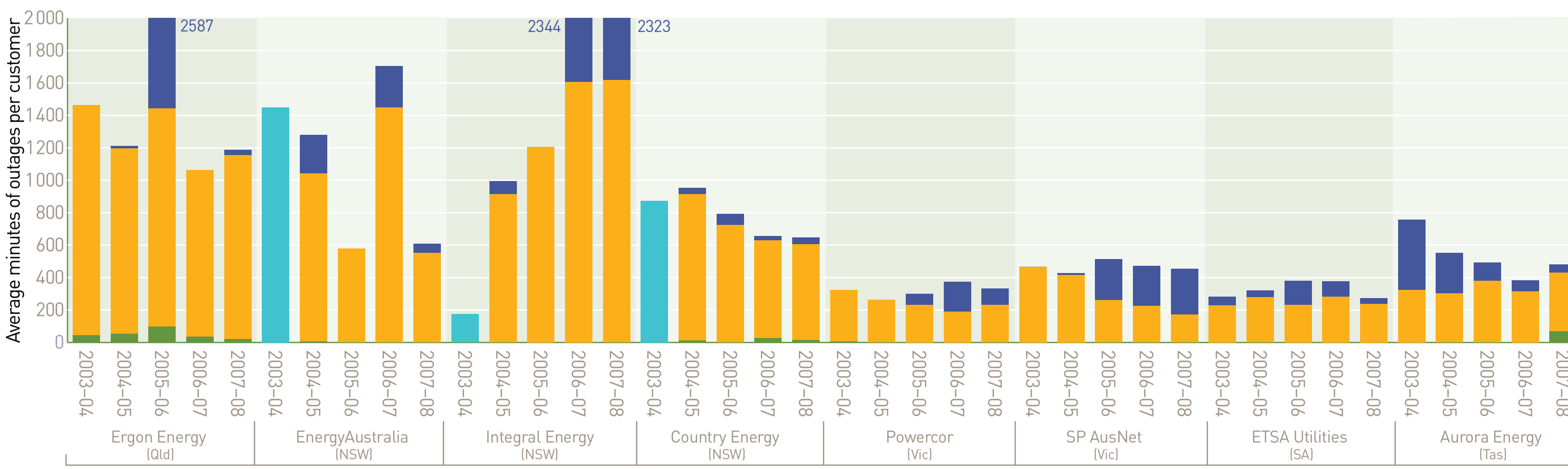


Figure 6.11d

Rural long feeders—average duration of supply interruptions per customer (SAIDI)



Notes for figures 6.11a–6.11d:

Victorian data are for the calendar year ending in that period.

Unallocated data do not provide a breakdown across categories.

Sources: Distribution network performance reports published by the ESC (Vic), IPART (NSW), the QCA (Qld), ESCOSA (SA), OTTER (Tas), EnergyAustralia, Integral Energy and Country Energy.

In summary, in the period from 2003–04 to 2007–08:

- CBD feeders were more reliable than other feeders. Most CBD customers experienced outages totalling less than 20 minutes per year. In 2007 CitiPower (Victoria) recorded unadjusted outages totalling 67 minutes—more than three times the level experienced in the previous five years. Most of these outages were the result of three excluded events, including load shedding during the 16 January 2007 bushfires. Unadjusted outages in Aurora Energy's (Tasmania) network averaged more than 100 minutes per customer. The increase in outages relative to the previous year was due to issues in the generation and transmission sectors.
- Urban customers typically experienced outages totalling around 50–150 minutes per year. Normalised outage time tended to be lowest for those networks with less dispersed customer bases. Networks in several jurisdictions experienced significant interruptions that were excluded from the normalised data. Extreme weather caused significant exclusions for Queensland in 2005–06 and New South Wales in 2006–07. SP AusNet (Victoria) had significant excluded events affecting its urban feeders for each of the last three years in the data period. The normalised data indicate that reliability was reasonably stable or improving over time in most networks.
- Rural short customers typically experienced normalised outages of around 100–300 minutes per year, with outages tending to be highest in New South Wales and Queensland. Ergon Energy (Queensland) customers typically experienced over 500 minutes of normalised outages. Weather related factors led to major exclusions in Queensland in 2005–06 and New South Wales in 2006–07.
- With a feeder route length of more than 200 kilometres, rural long customers experienced the least reliable electricity supply. Rural long customers in Victoria, South Australia and Tasmania experienced outages of around 200–400 minutes per year on average. The performance of the New South Wales and Ergon Energy (Queensland) networks was more variable, ranging from 600 minutes of outages to over 2000 minutes. In 2007–08 rural long customers serviced by Integral Energy (New South Wales) experienced normalised outages of over 1600 minutes (and total outages of over 2300 minutes) for the second year running.

6.6.2 Technical quality of supply

The technical quality of supply in a distribution network can be affected by issues such as voltage dips, swells and spikes, and television or radio interference. Some problems are network related (for example, the result of a network limit or fault), but others may be traced to an environmental issue or to a network customer.

Network businesses report on the technical quality of supply by disaggregating complaints into their underlying causes and categorising them. The complaint rate for technical quality of supply issues since 2004–05 has been less than 0.1 per cent of customers for most mainland distribution networks in the NEM. ENERGEX and Ergon Energy (Queensland) recorded complaint rates of 0.1 per cent and 0.3 per cent of customers respectively in 2007–08, with the performance of these networks having improved steadily since 2004–05. Western Power and Horizon Power (Western Australia) had complaint rates of 0.2 per cent and 0.3 per cent of customers respectively in 2007–08. Aurora Energy (Tasmania) recorded a complaint rate of 0.2 per cent of customers in 2007–08, lower than in the previous five years. Issues arise, however, when making performance comparisons across jurisdictions. In particular, the definition of 'complaint' adopted by each business may vary.

6.6.3 Customer service

Network businesses report on their responsiveness to a range of customer service issues, including:

- > timely connection of services
- > timely repair of faulty street lights
- > call centre performance
- > customer complaints.

Tables 6.7 and 6.8 provide a selection of customer service data for the networks. As noted, performance comparisons are difficult, given the significant differences across networks, as well as possible differences in definitions and in information, measurement and auditing systems.

Network performance in the timely provision of services in 2007–08 was broadly in line with that of previous years. ENERGEX recorded a significant increase in the number of late connections, and the New South Wales networks recorded longer average times for street light repairs. Call centre performance was similar to that of previous years, with the New South Wales and most Victorian networks recording slight improvements in 2007–08.

6.6.4 Service performance incentive schemes

Victoria and South Australia have applied financial incentive schemes for their distribution businesses to maintain and improve service performance over time. The model is an 's-factor' incentive scheme, similar to that applied to transmission networks.[25] The South Australian scheme focuses on customers with poor reliability outcomes.

The AER published details in May 2009 of an incentive scheme for service target performance as part of the national framework for distribution regulation.[26]

The scheme provides financial bonuses and penalties of up to 5 per cent of revenue to network businesses that meet (or fail to meet) performance targets. The targets relate to reliability of supply (duration and frequency of outages) and customer service. The results are standardised for each network to derive an 's-factor' that reflects deviations from target performance levels.

The national scheme includes a GSL component, which provides payments to customers that receive service below predetermined thresholds (for example, failure to attend service appointments). The GSL component does not apply where the distribution business is subject to jurisdictional GSL obligations (see section 6.6.5).

The national scheme is based on existing state based incentive schemes in Victoria and South Australia, so has regard to industry and community expectations. Over time, the national scheme will replace the state based schemes. The AER will first apply the national scheme in its current price reviews of the Queensland and South Australian distribution networks, scheduled to take effect in July 2010. While the AER considers the scheme should apply on a consistent basis nationally where practical, there is some flexibility to allow for transitional issues and the differing circumstances and operating environments of each network. The scheme will likely evolve over time to allow for factors such as changes in energy industry technology, climate change policies and other issues affecting customer expectations of service performance and the wider operating environment for the distribution sector. Table 6.9 shows how the scheme will apply in each jurisdiction.

The AER will publicly report on the service performance of distribution businesses in the future. It will consult with stakeholders on the reporting measures and future reporting arrangements.

25 The use of s-factor schemes is discussed in the context of electricity transmission in section 5.6 of this report.

26 AER, *Electricity distribution network service providers: service target performance incentive scheme, final decision*, Melbourne, June 2008.

Table 6.7 Timely provision of service by electricity distribution networks

NETWORK	PERCENTAGE OF CONNECTIONS COMPLETED AFTER AGREED DATE				PERCENTAGE OF STREETLIGHT REPAIRS COMPLETED AFTER AGREED DATE				AVERAGE NUMBER OF DAYS TO REPAIR FAULTY STREETLIGHT			
	2004–05	2005–06	2006–07	2007–08	2004–05	2005–06	2006–07	2007–08	2004–05	2005–06	2006–07	2007–08
QUEENSLAND[1]												
ENERGEX	3.98	0.62	0.54	10.79	5.4	4.8	7.6	4.8	3.5	4.5	4.0	3.0
Ergon Energy	6.62	0.84	0.49	0.72	9.7	21.5	17.9	…	2.8	3.9	3.5	…
NEW SOUTH WALES[2]												
EnergyAustralia	0.01	0.02	0.02	0.01	6.6	6.0	1.0	2.4	8.0	9.0	6.0	12.0
Integral Energy	0.01	0.02	0.02	0.01	5.5	0.9	1.0	2.4	2.0	2.0	2.0	3.0
Country Energy	0.02	0.02	0.02	0.01	1.3	1.0	1.0	2.4	9.0	8.0	8.0	10.0
VICTORIA												
Powercor	0.13	0.12	0.06	0.04	0.3	0.1	3.4	1.8	2.0	2.0	2.2	2.0
SP AusNet	0.03	0.21	2.40	2.66	1.0	0.8	0.1	0.0	2.0	2.0	1.4	1.0
United Energy	0.12	0.05	0.29	0.05	0.8	0.2	0.4	0.2	1.4	1.0	1.0	1.0
CitiPower	0.00	0.02	0.03	0.05	7.8	11.4	5.8	8.4	2.3	3.0	2.2	2.2
Jemena	0.14	0.12	0.09	0.19	6.1	6.9	1.1	0.9	2.0	3.0	2.4	1.9
SOUTH AUSTRALIA[1]												
ETSA Utilities	0.91	1.33	0.51	1.30	4.5	5.5	2.6	1.8	3.8	3.6	2.6	3.0
WESTERN AUSTRALIA												
Western Power	…	20.90	20.40	18.80	…	8.4	35.0	34.7	…	…	6.5	…
Horizon Power	…	0.00	0.00	15.60	…	0.0	23.0	15.1	…	2.0	6.8	…
TASMANIA												
Aurora Energy	…	0.15	0.14	2.00	10.5	12.3	14.0	…	…	…	…	…

1. Completed connections data for Queensland and South Australia include new connections only.
2. New South Wales completed connections data from 2005-06 and street light repair percentage data from 2006-07 are state averages.

Note: Victorian data are for the calendar year ending in that period.

Sources: Distribution network performance reports published by the ESC (Vic), IPART (NSW), the QCA (Qld), ESCOSA (SA), the ERA (WA), OTTER (Tas) and the ICRC (ACT). Some data are AER estimates derived from official jurisdictional sources.

Table 6.8 Call centre performance by electricity distribution networks

NETWORK	PERCENTAGE OF CALLS ABANDONED BEFORE REACHING HUMAN OPERATOR				PERCENTAGE OF CALLS ANSWERED BY HUMAN OPERATOR WITHIN 30 SECONDS			
	2004–05	2005–06	2006–07	2007–08	2004–05	2005–06	2006–07	2007–08
QUEENSLAND								
ENERGEX	2.2	3.9	3.0	3.8	89.4	89.4	79.1	96.3
Ergon Energy	2.8	3.5	2.3	2.5	85.0	85.1	87.0	86.2
NEW SOUTH WALES AND THE ACT								
EnergyAustralia	10.5	10.5	15.7	10.8	44.6	81.3	74.3	81.1
Integral Energy	6.0	3.2	8.7	3.8	81.0	89.0	70.9	96.2
Country Energy	41.2	42.6	31.1	27.4	48.4	47.2	…	61.4
ActewAGL	16.9	22.5	21.1	14.0	65.6	39.7	62.4	70.5
VICTORIA								
Powercor	5.9	7.0	7.0	4.0	90.9	88.7	86.7	89.4
SP AusNet	8.8	6.0	9.0	7.0	79.8	82.7	92.3	91.2
United Energy	7.7	24.0	18.0	17.0	75.6	73.8	72.9	74.0
CitiPower	10.8	10.0	5.0	4.0	88.2	89.2	85.7	87.2
Jemena	0.9	5.0	7.0	13.0	73.8	75.2	77.4	79.9
SOUTH AUSTRALIA								
ETSA Utilities	4.4	4.0	3.0	3.0	86.9	85.2	89.3	88.7
WESTERN AUSTRALIA								
Western Power	…	…	0.1	4.3	…	…	…	79.0
Horizon Power	…	…	9.4	4.5	…	…	70.0	83.0
TASMANIA								
Aurora Energy	1.0	9.3	5.6	4.0	…	…	…	…

Note: Victorian data are for the calendar year ending in that period.

Sources: Distribution network performance reports published by the ESC (Vic), IPART (NSW), the QCA (Qld), the ERA (WA), ESCOSA (SA), OTTER (Tas) and the ICRC (ACT). Some data are AER estimates derived from official jurisdictional sources.

Table 6.9 Service target performance incentive scheme for distribution businesses to be applied by the AER

NEW SOUTH WALES AND THE ACT	SOUTH AUSTRALIA	QUEENSLAND	VICTORIA
The national scheme will apply as a reporting requirement, but without financial incentives attached to targets. The AER will apply reliability of supply and customer service components. No GSL components will apply.	The national scheme will likely apply, with ±5 per cent of businesses' revenue at risk under the scheme. Targets will be attached to reliability of supply and customer service components. No GSL components will apply, because a jurisdictional GSL scheme applies.	The national scheme will likely apply, with ±2 per cent of revenue at risk under the scheme. Targets will be attached to reliability of supply and customer service components. No GSL components will apply, because a jurisdictional GSL scheme applies.	The national scheme will likely apply, with ±5 per cent of revenue at risk under the scheme. Targets will be attached to reliability of supply and customer service components. The GSL component will apply, replacing the jurisdictional GSL, which ceases on 1 January 2011.

Sources: New South Wales and the ACT distribution determinations, April 2009; Framework and approach papers for the Queensland, South Australian and Victorian networks.

Table 6.10 Guaranteed service levels of electricity distribution networks

	NATIONAL (AER)	QLD[1]	NSW	VIC	SA	WA	TAS	ACT
RELIABILITY MEASURES								
Duration of supply interruptions exceeds specified limit	$80 per interruption	$80 per interruption	$80 per interruption (maximum $320 per year)	$100–300 per year	$80–320 per interruption	$80 per interruption	$80–160 per interruption	$20 per interruption
Frequency of supply interruptions exceeds specified limit	$80 per interruption	$80 per year	$80 per year	$100–300 per year	$80–160 per year		$80 per year	
Frequency of momentary supply interruptions (less than 1 minute) exceeds specified limit				$25–35 per year				
CUSTOMER SERVICE MEASURES								
Wrongful disconnection		$100						
Late connection	$50 per day (maximum $300)	$40 per day	$60 per day (maximum $300)	$50 per day (maximum $250)	$50 per day		$30 per day (maximum $150)	$60 per day (maximum $300)[2]
Late reconnection		$40 per day						
Failure to attend a scheduled appointment on time		$40	$25	$20	$20		$30	
Failure to respond to a complaint in designated timeframe						$20		$20
Failure to give sufficient notice of a planned interruption	$50	$20 (residential) $50 (business)	$20			$20	$30	$50
Planned interruptions not completed in specified time			$20					$50
Late repair of street lights	$25		$15	$10	$20 per five or 10 day period		$30 per day (maximum $150)	
Late response to an inquiry regarding loss of hot water		$40 per day						
Altered condition of property due to vegetation clearing							$30	

1. Queensland has a cap on payments of $320 per customer per year (excludes wrongful disconnection payments). The QCA has approved increases in compensation payments of about 30 per cent, to apply from 1 July 2010.
2. Includes the response time for a reported fault or damage.

6.6.5 Guaranteed service levels

The GSL schemes provide for payments to customers that experience poor service. They are not intended to provide legal compensation to customers, but to enhance service performance by distribution businesses.

A range of GSL schemes apply across the jurisdictions. With the shift to national distribution regulation, the AER published details in 2009 of a national GSL scheme as part of the service target performance incentive scheme (see section 6.6.4). But the jurisdictional schemes will continue in some instances: both the Essential Services Commission of South Australia (ESCOSA) and the QCA have indicated they will retain their jurisdictional schemes. However, the national scheme will likely apply to the Victorian networks in the next regulatory period.

The GSL schemes provide payments for poor service quality in areas such as streetlight repair, frequency and duration of supply interruptions, new connections and notice of planned interruptions. Table 6.10 details the performance criteria and associated compensation payments. Payments under the national scheme are made automatically to consumers if service is below target. This arrangement differs from most jurisdictional schemes under which payments are made only if affected customers apply.

Given each jurisdiction reports against different criteria, it is not possible to compare the performance of distribution businesses against GSL targets across jurisdictions. Further, given payments are generally made only if a customer applies, outcomes over time may reflect both changes in customer awareness and business performance.

The majority of GSL payments in 2007–08 in most jurisdictions related to the duration and frequency of supply interruptions exceeding specified limits. Payments in Queensland resulted mainly from wrongful disconnections and late connections.

- In Queensland, GSL payments in 2007–08 were the equivalent of $0.07 per customer for Ergon Energy and $0.09 per customer for ENERGEX.
- In New South Wales, GSL payments in 2007–08 were equivalent to $0.02 per customer. Eighty per cent of the payments were made by Country Energy, with EnergyAustralia and Integral Energy accounting for around 10 per cent each. There was a slight rise in total payments over the previous five years.
- In Victoria, GSL payments in 2007–08 were equivalent to $2.21 per customer—around one third higher than the previous year's. However, the performance of individual businesses varied. The majority of payments were made by the predominantly rural networks SP AusNet (81 per cent of total payments by Victorian businesses) and Powercor (18 per cent).
- In South Australia, GSL payments by ETSA Utilities fell by 74 per cent between 2005–06 and 2007–08. Payments in 2007–08 were the equivalent of $0.64 per customer.
- In Western Australia, Western Power's 2007–08 payments were equivalent to $0.26 per customer. This was an improvement on 2006–07 but above 2005–06 levels. Horizon Power's payments in 2007–08, equivalent to $0.06 per customer, were lower than those in the previous two years.
- In Tasmania, GSL payments in 2007–08 (equivalent to $2.00 per customer) were three times greater than the previous year's, but consistent with 2005–06 outcomes.

6.7 Policy developments in electricity distribution

Recent policy activity in the distribution sector has focused on network planning and operation and the approach to economic regulation. The following section summarises policy developments in these areas. Appendix A describes the institutional bodies responsible for developing and implementing energy policy.

6.7.1 Network planning and expansion

On 17 December 2008 the Ministerial Council on Energy (MCE) agreed to establish a national framework for distribution network planning.

As part of this process, the MCE directed the Australian Energy Market Commission (AEMC) to review the distribution network planning and expansion arrangements in the NEM. The AEMC submitted its final report to the MCE in September 2009.[27]

The planning framework, once finalised, is intended to ensure clear and efficient planning and investment processes. Recommendations include:

- requiring distribution businesses to publish annual planning reports looking forward a minimum of five years
- replacing the current regulatory test with a regulatory investment test for distribution—similar to the new test for transmission investment (see section 5.8.2)
- establishment of a demand-side engagement strategy to ensure that non-network solutions to address system limitations are fully considered.

6.7.2 Network connection

In March 2009 the MCE's network policy working group made its final recommendations on a national framework for the connection of customers to distribution networks.[28] The working group found the process for network connection should be simplified and streamlined. Its report recommended distribution businesses be required to have at least one standard connection service for a customer load category (for example, small customers) and at least one standard connection service for micro embedded generators.[29]

The working group suggested two possible methods for connection to a distribution network:

- standard connections, with a short period (five days) for a connection offer to be made following an application
- negotiated connections, to be provided on an individual basis and allow more time for offers to be prepared.

A national framework for electricity distribution connection will incorporate these recommendations. The framework is being drafted in 2009, with legislative proposals expected in 2010. Once implemented, it will provide a single customer framework for the provision of electricity and gas connections.

6.7.3 Total factor productivity approach

In 2008 the AEMC commenced a review of the total factor productivity (TFP) approach in energy regulation. TFP is a method that measures how businesses use resources to produce output. It exposes regulated businesses to competitive pressures by linking revenues to industry performance rather than the cost structures of specific businesses.

The AEMC will advise the MCE on the potential use of TFP assessments, in conjunction with the building block approach, to determine network revenues and price. The TFP assessment would be used to judge the reasonableness of network expenditure forecasts under the building block method. The AEMC has identified potential benefits from applying a TFP method, including:

- lower regulatory administrative costs
- reduced information asymmetry between regulated businesses and regulators
- stronger performance incentives to the regulated business.[30]

The AEMC expects to finish its review in April 2010, with any recommended rule changes to be considered by the MCE in June 2010. The review will consider:

- the strength of incentives for networks to pursue efficient costs and share efficiencies with customers
- whether the TFP framework leads to efficient investment with innovation and technical progress
- clarity, certainty and transparency in the regulatory framework and processes to reduce avoidable risks for service providers and customers.

27 AEMC, *Review of national framework for electricity distribution network planning and expansion, final report*, Sydney, September 2009.

28 MCE Network Policy Working Group, *National connections framework for electricity distribution businesses, final report*, Canberra, March 2009.

29 A micro embedded generator is a generator with a rating below 10 kilovolt amperes (kVa) (for single phase power) or 30 kVa (for three phase power) that is connected to the distribution network.

30 AEMC, *Review into the use of total factor productivity for the determination of prices and revenues: framework and issues paper*, Sydney, December 2008.

6.7.4 Climate change policy

The AEMC has conducted a review of the likely impacts of climate change policies—particularly the carbon pollution reduction scheme and expanded renewable energy target—on energy market frameworks. It released the final report in October 2009.[31]

The AEMC found the main challenges for distribution networks are the potential growth in embedded generation and the increased variability of network flows, leading to the need for more active management of demand. These changes would make network management more complex and require new investment in network infrastructure. Despite these challenges, the AEMC considered the current regulatory framework is sufficiently flexible to accommodate the evolving demands on network businesses.

The AEMC noted initiatives to facilitate innovation in the management of network reliability, including the demand management innovation allowance (see section 6.8.1). It recommended expanding the allowance to cover innovations in the connection of embedded generators to distribution networks.

6.8 Demand management and metering

6.8.1 Demand management

Demand management (or demand-side participation) relates to strategies to manage the growth in overall or peak demand for energy services. The objective is to reduce or shift demand, or implement efficient alternatives to network augmentation. Demand management in the NEM is constantly evolving, with a number of initiatives being implemented. The initiatives are primarily undertaken at the retail or distribution level and require cooperation between energy customers and suppliers.

The demand management programs trialled in Australia include:

> controlling the load for residential appliances such as air conditioners and pool pumps. Under these schemes, appliances are remotely switched off (or cycled on and off) at times of peak demand.

> providing price signals to consumers to encourage them to shift some energy consumption away from times of peak demand. Trialled methods for residential customers include time-of-use and critical peak pricing.[32] The strategies require advanced metering equipment and flexible tariff arrangements. Some distributors have entered into contracts with large energy customers to reduce consumption at peak times.

> supporting embedded generation, where back-up generation is enabled in large business facilities, as a substitute for network augmentation.

The regulatory process allows for funding to encourage these initiatives. The AER has launched demand management schemes for New South Wales and the ACT, Queensland, South Australia and Victoria. The schemes provide funding to trial and implement demand management solutions. Some of the schemes allow for the recovery of forgone revenue arising from lower demand for network services. Table 6.11 sets out how the schemes will apply in each jurisdiction.

In 2009 the AEMC completed a review of whether there are regulatory impediments to demand-side participation in the NEM.[33] The review investigated whether the current regulatory arrangements are biased towards expanding generation and network capacity to meet demand for electricity, rather than taking more cost-effective approaches to reduce demand.

The AEMC published a draft report in April 2009 that identified material barriers to demand-side participation that are attributable to regulated network businesses.

31 AEMC, *Review of energy market frameworks in light of climate change policies, final report*, Sydney, October 2009.

32 Critical peak pricing involves retailers charging a higher tariff at times of extreme demand. Retailers have some flexibility in when they can institute the higher price; however, there is usually a limit on the number of times the tariff can be used, along with requirements for customers to receive sufficient notice.

33 AEMC, *Demand side participation in the national electricity market, draft report*, Sydney, April 2009.

Table 6.11 Demand management incentive schemes to be applied by the AER for electricity distribution businesses

NEW SOUTH WALES	THE ACT	SOUTH AUSTRALIA	QUEENSLAND	VICTORIA
In addition to a demand management innovation allowance, the New South Wales businesses are subject to a d-factor mechanism that allows businesses to recover: > approved non-tariff based demand management implementation costs > tariff based demand management implementation costs > revenue forgone as a result of non-tariff based demand management initiatives.	The ACT distribution network business, ActewAGL, will receive a demand management innovation allowance.	In addition to a demand management innovation allowance, the South Australian network business, ETSA Utilities, is also subject to a forgone revenue mechanism that allows it to recover revenue forgone where demand is successfully reduced by expenditure of the innovation allowance.	The Queensland distribution network businesses, ENERGEX and Ergon Energy, will receive a demand management innovation allowance.	In addition to a demand management innovation allowance, Victorian network businesses are subject to a forgone revenue mechanism that allows it to recover: > revenue forgone where demand is successfully reduced by expenditure of the innovation allowance > an annual allowance to spend on demand management > a forgone revenue component.

The following are noteworthy:

> The current method for setting network prices penalises businesses that use demand management initiatives to defer capital expenditure.
> Businesses have limited financial incentives to innovate under current regulatory approaches. The AEMC considers that 'use it or lose it' funding for innovation may be a proportionate way of addressing such a barrier, by allowing network businesses to recover costs associated with approved innovation projects outside their normal operating or capital expenditure requirements.
> Variability in network connection, planning and consultation processes across network businesses is a barrier to effective demand-side participation.
> Price cap regulation provides networks with incentives to undertake socially efficient demand-side participation.[34]

The AEMC has also considered demand management issues for transmission networks. In response to a proposal from the Total Environment Centre, it implemented amendments to the Electricity Rules. These rule changes support the provision of information about projected network constraints to market participants. This information assists demand management service providers to participate actively in the market and consider efficient alternatives to network augmentation. The amendments relate to:

> network businesses' provision of specific information about forecast constraints in their annual planning reports
> the AER's treatment of non-network expenditure (including demand management activities) incurred by network businesses in future revenue determinations
> obligations on the AER when assessing revenue proposals, to account for whether the network businesses have demonstrated, and provided for, appropriate efficient non-network alternatives
> obligations on network businesses to provide information on appropriate non-network alternatives in their revenue proposals.[35]

6.8.2 Metering

Meters record the energy consumption of customers at the point of connection to the distribution network. Effective metering, when coupled with appropriate price signals, can encourage more active demand management by customers.

34 AEMC, *Demand side participation in the national electricity market, draft report*, Sydney, April 2009.
35 AEMC, *Rule Determination, National Electricity Amendment (Demand Management) Rule 2009*, Sydney, April 2009.

There are two main types of meter:

- The older style *accumulation meters* record the total consumption of electricity at a connection point, but not the time of consumption. Consumers are billed on solely the volume of electricity consumed.
- *Interval meters* are more sophisticated and record consumption in defined time intervals (for example, half hour periods). This allows time-of-use billing so the charge for electricity can be varied with the time of consumption. Industry generally uses interval meters.

Plans are being implemented at the national and state levels to introduce *smart meters*, which are an advanced type of interval meter. These meters have remote communication capabilities between retailers and customer that allow for remote meter reading and connection/disconnection of customers. Add-ons such as an in-house display may provide prices and other aspects of electricity consumption, as well as real time information on power outages. The meters are also compatible with technology that allows retailers and distribution businesses to manage loads to particular customers and appliances.

The take-up of smart meters has varied among jurisdictions:

- In New South Wales, distribution businesses are rolling out interval meters for customers using more than 15 megawatt hours of electricity a year. For smaller customers, interval meters are provided on a new and replacement basis. The New South Wales Government has committed to a full rollout of smart meters by 2017.
- The Victorian Government has initiated a program to provide smart meters to all customers over a four year period from 2009. In January 2009 the AER released a framework and approach paper that sets out the process for determining the prices that distribution businesses can charge for metering services.[36] The Victorian distributors have submitted to the AER budget applications for metering expenditure to 2011. The AER is scheduled to release a final determination on initial budgets and charges on 31 October 2009. Distribution businesses, after installing an interval meter for a customer, are entitled to reassign the customer to a time-of-use tariff.[37] In May 2009 the AER released notification requirements that a distribution business must provide to customers before this change can occur.[38]
- A number of other jurisdictions are rolling out smart meters on a new and replacement basis.

In 2007 the Council of Australian Governments (COAG) agreed to a national implementation strategy for the progressive rollout of smart meters where the benefits outweigh costs. A cost–benefit assessment published in March 2008 found a national rollout would achieve a net benefit.[39] However, in June 2008 the MCE noted uncertainties in the levels of costs and benefits, and supported the implementation of trials and further analysis to help verify jurisdictional costs and benefits.[40]

The MCE is developing a framework to support a rollout of smart electricity meters in the NEM, noting that consistency between NEM and non-NEM jurisdictions will be sought as appropriate. The MCE is focusing on regulatory arrangements (including cost recovery arrangements), consumer protection measures and safety standards. A national stakeholder steering committee was established to lead the development of technical and operational aspects of the framework. The steering committee is also responsible for reviewing progress of jurisdictional pilots and trials.

The MCE has estimated the current process should result in more than 50 per cent of all Australian meters being replaced by 2017. It will consider a timetable for a further rollout of smart meters by June 2012.[41]

36 AER, *Framework and approach paper, Advanced metering infrastructure review 2009–11, final decision*, Melbourne, January 2009.

37 Where the customer consumes less than 20 megawatt hours of electricity per year.

38 AER, *Interval meter reassignment requirements, final decision*, Melbourne, May 2009.

39 NERA, *Cost benefit analysis of smart metering and direct load control overview report for consultation*, Prepared for the Smart Meter Working Group, Sydney, February 2008.

40 MCE, *Communiqué*, Canberra, 13 June 2008.

41 MCE, *Communiqué*, Canberra, 13 June 2008.

7 ELECTRICITY RETAIL


Bernd Vogel (Corbis)

The retail market is the final link in the electricity supply chain. It provides the main interface between the electricity industry and customers such as households and small businesses. Retailers deal directly with consumers, so the services they provide can significantly affect perceptions of the performance of the electricity industry.

Retailers buy electricity in the wholesale market and package it with transportation for sale to customers. Many retailers sell 'dual fuel' products that bundle electricity and gas services. While retailers provide a convenient aggregation service for electricity consumers, they do not directly provide network services.

7 ELECTRICITY RETAIL

This chapter provides a survey of electricity retail markets. It covers:

> the structure of the retail market, including industry participants and trends towards horizontal and vertical integration
> the development of retail competition
> retail market outcomes, including price and service quality
> the regulation of the retail market
> energy efficiency.

State and territory governments are currently responsible for the regulation of retail energy markets. Governments agreed in 2004, however, to transfer several non-price regulatory functions to a national framework that the Australian Energy Market Commission (AEMC) and the Australian Energy Regulator (AER) would administer. The Ministerial Council on Energy (MCE) has scheduled the regulatory package to be introduced to the South Australian parliament in 2010.[1]

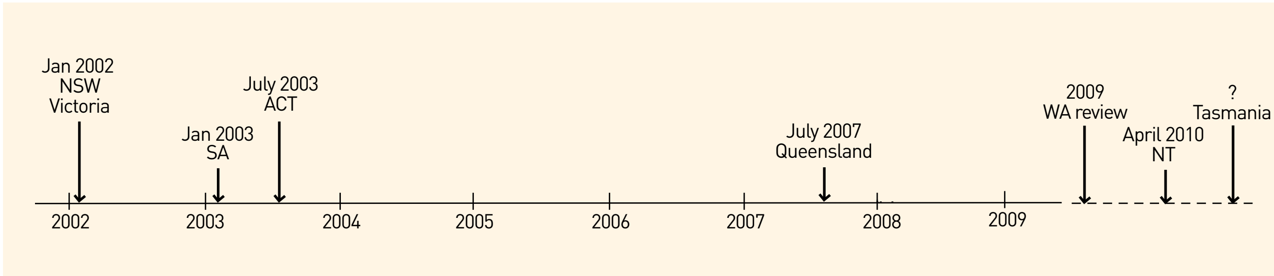
This chapter focuses on the retailing of electricity to small customers, including households and small business users.[2] Large customers such as major industrial users buy the greatest volume of electricity, but they are relatively few in number. While the chapter reports some data that may enable performance comparisons across retailers, such analysis should note that a variety of factors can affect relative performance.

1 Section 7.7 provides an update on the transition to a national regulatory framework.

2 In New South Wales, Victoria, South Australia and Western Australia, small customers are those consuming less than 160 MWh per year. In Queensland and the Australian Capital Territory, small customers are those consuming less than 100 MWh per year. Small customers in Tasmania are those consuming less than 150 MWh per year.

Figure 7.1

Introduction of full retail contestability



7.1 Retail market structure

The privatisation of energy retail assets is continuing. Victoria and South Australia privatised their energy retail businesses in the 1990s, and Queensland privatised most of its energy retail entities in 2006–07. The Australian Capital Territory (ACT) Government operates a joint venture with the private sector to provide retail services. At 1 July 2009 New South Wales, Western Australia, Tasmania and the Northern Territory retained government ownership in the retail sector. The New South Wales Government in March 2009, however, affirmed its intention to privatise its energy retail businesses.[3] Subject to market conditions, it expects to complete the sale process in the first half of 2010.[4]

Australian governments have also introduced retail contestability (customer choice) since the mid 1990s. Most governments have adopted a staged timetable to introduce customer choice, beginning with large industrial customers followed by small industrial customers and finally small business and domestic customers. Full retail contestability (FRC) is achieved when all customers are permitted to enter a supply contract with a retailer of their choice.

The introduction of contestability arrangements has varied across jurisdictions (figure 7.1):

> New South Wales, Victoria, Queensland, South Australia and the ACT have introduced FRC.

> From 1 July 2009 Tasmania extended contestability to customers using at least 150 megawatt hours (MWh) per year. Contestability will not be extended to smaller customers until at least July 2010.[5]

> Western Australia allows contestability for customers using at least 50 MWh annually. The Office of Energy in 2008 and 2009 reviewed the electricity retail market and considered a possible introduction of FRC.[6]

> The Northern Territory plans to introduce FRC in April 2010, subject to a public benefit test. In August 2009 the Utilities Commission released an issues paper that considers options for the implementation of FRC for small businesses and households in the Northern Territory.[7]

The retail players in each jurisdiction include:

> one or more 'host' retailers that are subject to additional regulatory obligations

> new entrants, including established interstate players, gas retailers branching into electricity retailing and new players in the energy retail sector.

3 Nathan Rees (Premier of New South Wales), 'Strengthening the New South Wales economy: energy reforms begin new phase', Media release, 5 March 2009.

4 Joe Tripodi (Minister for Infrastructure, New South Wales), 'NSW Government releases energy reform transaction strategy', Media release, 10 September 2009.

5 Office of the Tasmanian Economic Regulator, 'The power to choose', viewed 11 May 2009, www.power.tas.gov.au. The Tasmanian Government has yet to decide whether to extend FRC to all customers.

6 Office of Energy (Western Australia), *Electricity retail market review—issues paper*, Perth, December 2007.

7 Regulation 6(4), Electricity Reform (Administration) Regulations 2008 (NT); Utilities Commission, *Review of full retail contestability for Northern Territory electricity customers—issues paper*, Darwin, August 2009.

Table 7.1 Active electricity retailers—small customer market, April 2009

RETAILER[1]	OWNERSHIP	QLD	NSW	VIC	SA	WA	TAS	ACT	NT
ActewAGL Retail	ACT Government & AGL Energy		New entrant					Host	
AGL Energy	AGL Energy	New entrant	New entrant	Host	Host				
Alinta Sales	Babcock & Brown Power					New entrant			
Aurora Energy	Tasmanian Government				New entrant		Host		
Australian Power & Gas	Australian Power & Gas			New entrant					
Click Energy	Click Energy			New entrant					
Country Energy	NSW Government	New entrant	Host	New entrant	New entrant				
Energy Australia	NSW Government	New entrant	Host	New entrant					
Ergon Energy	Queensland Government	Host							
Horizon Power	Western Australian Government					Host			
Integral Energy	NSW Government	New entrant	Host						
Jackgreen	Jackgreen Ltd[2]	New entrant	New entrant	New entrant	New entrant				
Momentum Energy	Momentum Energy[3]			New entrant	New entrant				
Neighbourhood Energy	Neighbourhood Energy[4]			New entrant					
Origin Energy	Origin Energy	Host	New entrant	Host	New entrant				
Perth Energy	Infratil					New entrant			
Power and Water Corporation	Northern Territory Government								Host
Powerdirect	AGL Energy	Host	New entrant	New entrant	New entrant				
Queensland Electricity	Infratil	New entrant							
Red Energy	Snowy Hydro[5]			New entrant	New entrant				
Sanctuary Energy	Sanctuary Energy Pty Ltd[6]	New entrant							
Simply Energy	International Power			New entrant	New entrant				
South Australian Energy	Infratil				New entrant				
Synergy	Western Australian Government					Host			
TRUenergy	CLP Group	New entrant	New entrant	Host	New entrant			New entrant	
Victoria Energy	Infratil			New entrant					
Active retailers		11	9	14	11	4	1	2	1
Approx. market size ('000 000 customers)		1.9	3.1	2.4	0.8	1.0	0.2	0.2	0.1

Host (incumbent) retailer   New entrant retailer

1. Not all licensed retailers are listed. Some generators are licensed retailers but are active only in the market for larger industrial users. Not all retailers listed supply electricity to all customers—for example, some retailers market to only small business users.
2. Babcock & Brown Infrastructure's stake in Jackgreen was bought by institutional investors in August 2009.
3. In September 2008 Hydro Tasmania acquired a controlling interest (51 per cent) in Momentum Energy, and it will purchase the remaining 49 per cent in 2010.
4. The major shareholder of Neighbourhood Energy at 30 June 2008 was Babcock & Brown Power (65 per cent).
5. Snowy Hydro is owned by the New South Wales Government (58 per cent), the Victorian Government (29 per cent) and the Australian Government (13 per cent).
6. Sanctuary Energy Pty Ltd is owned by Living Choice Australia Ltd (50 per cent) and Sanctuary Life Pty Ltd (50 per cent).

Sources: Jurisdictional regulator websites, retailer websites and other public sources.

State government owned host retailers in New South Wales, Tasmania, Western Australia and the Northern Territory are the major players in those jurisdictions. The ACT Government operates a joint venture with a privately owned business to provide electricity retail services.

Privately owned retailers are the major players in Victoria, South Australia and Queensland. The largest private retailers are AGL Energy, Origin Energy and TRUenergy. Each has significant market share in Victoria and South Australia, and is building market share in New South Wales. AGL Energy and Origin Energy entered the Queensland small customer market in 2006–07 following the privatisation of government owned retailers. International Power, trading as Simply Energy, continues to emerge as a significant retail business in Victoria and South Australia.

Niche players are active in most jurisdictions. Table 7.1 lists licensed retailers that were active in the market for residential and small business customers in April 2009.[8] Active retailers are those that currently offer supply contracts to new small customers.

The following survey (sections 7.1.1–7.1.8) provides background on developments in each jurisdiction.[9]

7.1.1 Queensland

At April 2009 Queensland had 24 licensed retailers,[10] of which 11 were active in the small customer market. Origin Energy and AGL Energy are the biggest private retailers in Queensland, with Integral Energy emerging as the third major player. Sanctuary Energy was granted a retail licence in 2008 and commenced retailing to small customers. The Queensland Government has retained ownership of Ergon Energy's retail business, which supplies the majority of customers in rural and regional areas.

Table 7.2 sets out the estimated small customer market share of Queensland retailers (by customer numbers) at 30 June 2008.

Table 7.2 Electricity retail market share (small customers)—Queensland, 30 June 2008

RETAILER	SMALL CUSTOMERS (%)
Origin Energy	36
Ergon Energy	33
AGL Energy	19
Other	12
Total small customers (no.)	1 930 000

Source: QCA estimates.

7.1.2 New South Wales

At April 2009 New South Wales had 26 licensed retailers, of which nine supplied (or intended to supply) residential and/or small business customers. The active retailers were:

- the government owned host retailers—EnergyAustralia, Country Energy and Integral Energy
- six new entrants—the state's host retailer in gas (AGL Energy), three established interstate players (Origin Energy, TRUenergy and ActewAGL Retail) and two new players in the energy retail market (Powerdirect and Jackgreen).

Momentum Energy, New South Wales Electricity, Dodo Power & Gas and Red Energy held retail licences but were not actively marketing to small customers. At April 2009 Australian Power & Gas continued to provide retail services to existing customers in New South Wales but was not accepting new customers.

At June 2008 new entrant retailers had acquired about 17 per cent of the small customer market (based on customer numbers) from the government owned incumbents. This share was up from about 14 per cent in the previous year.[11]

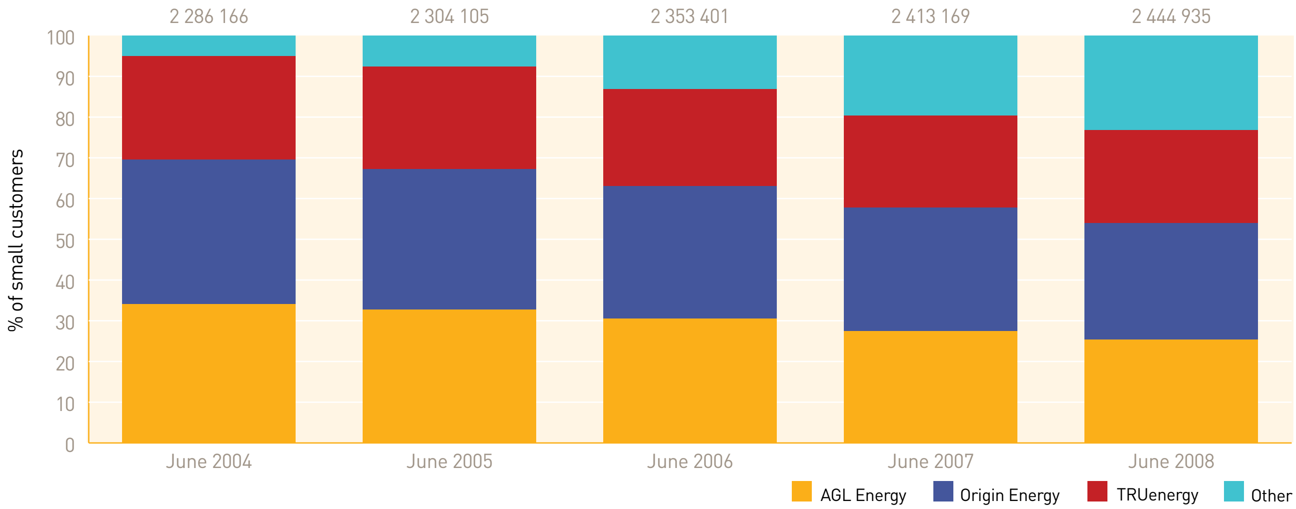
8 See footnote 2 for jurisdictional classifications of 'small customers'.

9 The number of licensed retailers may not correspond with the actual number of retail licences issued, because several licence holders may operate under a single trading name.

10 The number of licences issued may not correspond with the number of licensed retailers because a retailer may hold more than one licence.

11 IPART (New South Wales), NSW Electricity Information Paper, *Electricity retail businesses' performance against customer service indicators in NSW: for the period 1 July 2003 to 30 June 2008*, Sydney, March 2009, p. 2.

Figure 7.2
Electricity retail market share (small customers)—Victoria



Note: Figures at top of columns are total small customer numbers.

Source: ESC (Victoria), *Energy retailers: comparative performance report—customer service*, Melbourne, various years.

7.1.3 Victoria

At April 2009 Victoria had 29 licensed retailers, of which 14 were active in the residential and small business market. The active retailers were:

- the host retailers in designated areas of Victoria—AGL Energy, Origin Energy and TRUenergy
- eleven new entrants—two established interstate retailers (Country Energy and EnergyAustralia) and nine new players in the energy retail market (Simply Energy, Click Energy, Jackgreen, Neighbourhood Energy, Powerdirect, Red Energy, Victoria Electricity, Momentum Energy and Australian Power & Gas).

Dodo Power & Gas held a retail licence but was not actively marketing to small customers in April 2009.

Table 7.3 sets out the market share of Victorian retailers (by customer numbers) at 30 June 2008. The three host retailers account for about 77 per cent of the market, and each has acquired market share beyond its local area. New entrant penetration in the market increased from 13 per cent of small customers in June 2006 to about 23 per cent in June 2008 (figure 7.2).

Table 7.3 **Electricity retail market share (small customers)—Victoria, 30 June 2008**

RETAILER	CUSTOMERS		
	DOMESTIC (%)	BUSINESS (%)	TOTAL (%)
AGL Energy	25.8	21.6	25.3
Origin Energy	27.9	33.9	28.6
TRUenergy	22.9	23.1	22.9
Other	23.4	21.5	23.2
Total customers (no.)	2 155 995	288 940	2 444 935

Source: ESC (Victoria), *Energy retailers: comparative performance report—customer service 2007–08*, Melbourne, December 2008, p. 5.

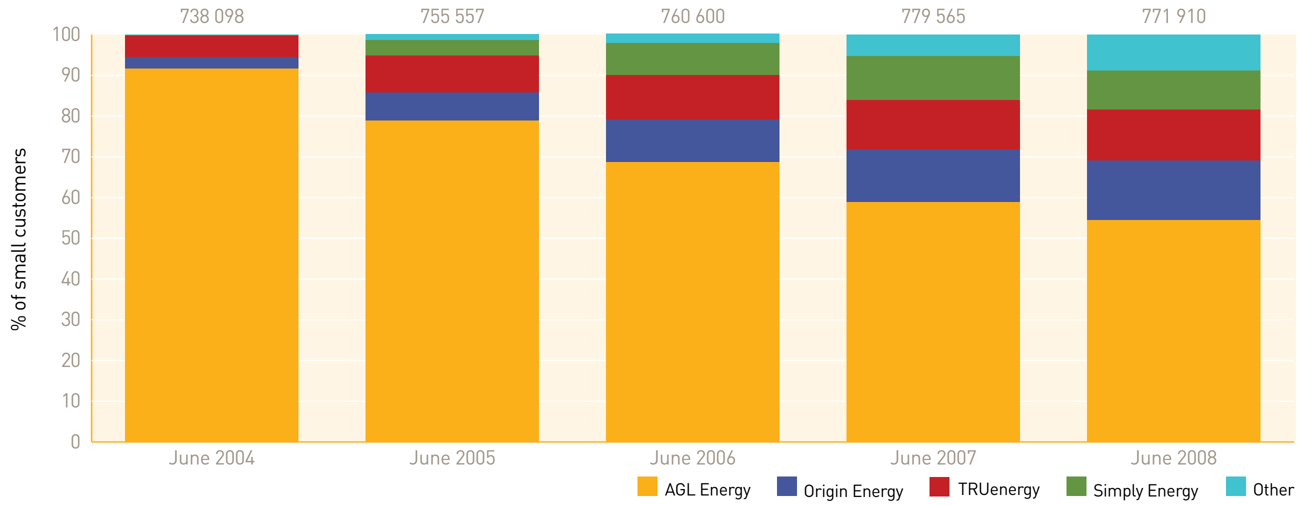
7.1.4 South Australia

At April 2009 South Australia had 16 licensed electricity retailers, of which 11 were active in the small customer market. The active retailers were:

- the host retailer—AGL Energy
- ten new entrants—South Australia's host retailer in gas (Origin Energy), three established interstate retailers (TRUenergy, Country Energy and Aurora Energy) and six new players in the energy retail market (Simply Energy, Momentum Energy, Powerdirect, South Australia Electricity, Red Energy and Jackgreen).

Figure 7.3

Electricity retail market share (small customers)—South Australia



Note: Figures at top of columns are total small customer numbers.

Source: ESCOSA (South Australia), *Annual performance report: performance of South Australian energy retail market*, various years.

EnergyAustralia, Dodo Power & Gas and Australian Power & Gas held retail licences but were not actively marketing to small customers in April 2009.

Table 7.4 sets out the small customer market share of South Australian retailers (by customer numbers) at 30 June 2008. The host retailer—AGL Energy—supplied 55 per cent of small customers, down from 59 per cent in June 2007. Other retailers have built market share, with Origin Energy and TRUenergy each supplying more than 10 per cent of the small customer base. Simply Energy's market share slipped to just below 10 per cent at June 2008 (figure 7.3). There has been only marginal penetration by niche retailers, with the four largest retailers accounting for over 90 per cent of the market.

Market penetration by new entrants has been more effective for large customers, with AGL Energy's market share eroding to about 36 per cent (based on sales volume).[12]

Table 7.4 Electricity retail market share (small customers)—South Australia, 30 June 2008

RETAILER	CUSTOMERS		
	DOMESTIC (%)	BUSINESS (%)	TOTAL (%)
AGL Energy	53.4	63.0	54.5
Origin Energy	14.3	16.0	14.5
TRUenergy	13.1	8.4	12.6
Simply Energy	10.1	4.2	9.5
Other	9.0	8.4	8.9
Total customers (no.)	687 072	84 838	771 910

Note: Rounding means market share data may not add to 100 per cent.

Source: ESCOSA (South Australia), *2007–08 Annual performance report: performance of South Australian energy retail market*, Adelaide, November 2008, p. 70.

7.1.5 Western Australia

In Western Australia, only customers consuming at least 50 MWh annually are contestable. They represent around 60 per cent of the retail market (by volume) in the South West Interconnected System (SWIS).[13] The government owned host retailer—Synergy—has a market share of 96 per cent of small

12 ESCOSA (South Australia), *2007–08 Annual performance report: performance of South Australian energy retail market*, Adelaide, November 2008, p. 27.

13 The SWIS is the main electricity grid in Western Australia and connects Perth, Geraldton, Kalgoorlie and the south west. See chapter 4 for further information on the SWIS.

residential customers and 92 per cent of small non-residential customers in the SWIS. Horizon Power services the regional areas of Western Australia outside of the SWIS, and is the second largest retailer, with 3.6 per cent of small residential customers and 5 per cent of small non-residential customers.[14] The remaining customers are divided among Alinta Sales (owned by Babcock & Brown Power), Perth Energy and the Rottnest Island Authority.

For further information on Western Australia, see chapter 4 of this report.

7.1.6 Tasmania

Aurora Energy, the government owned host retailer, controls the small customer market in Tasmania. Legislative restrictions prevent new entrants from supplying small customers.

7.1.7 Australian Capital Territory

At April 2009 the ACT had 15 licensed retailers, of which two were active in the residential market: ActewAGL Retail (the host retailer) and TRUenergy. At April 2009 Country Energy and Energy Australia continued to provide retail services to existing customers in the ACT, but were not accepting new customers. Aurora Energy, Dodo Power & Gas, ERM Power, Integral Energy, Jackgreen, Powerdirect, Red Energy, Australian Power & Gas, Sun Retail and Origin Energy held retail licences but were not actively marketing to small customers.

7.1.8 Northern Territory

The Northern Territory's electricity market is small, with around 82 500 customers connected to the network. The government owned host retailer, Power and Water Corporation, provides electricity services to these customers.

7.2 Trends in market integration

Various ownership consolidation activity has occurred in the energy retail sector in recent years, including:

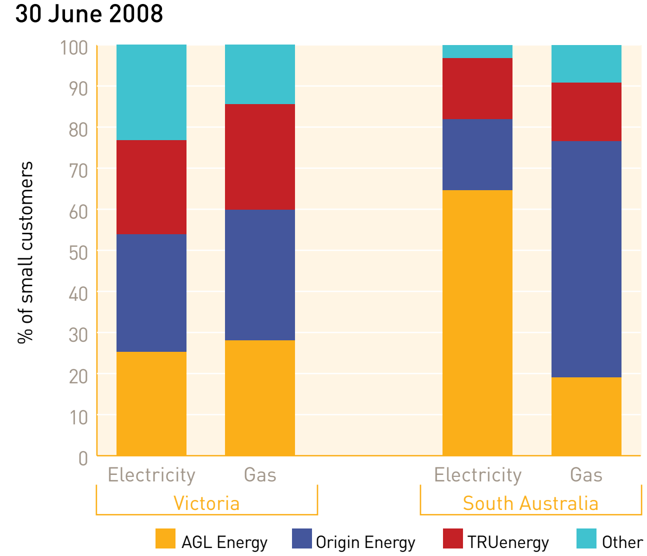
- retail market convergence of electricity and gas
- vertical integration of electricity retailers and generators.

7.2.1 Energy retail market convergence

Many energy retailers offer both electricity and gas services, including 'dual fuel' retail products.[15] The largest retailers in Victoria and South Australia (AGL Energy, Origin Energy and TRUenergy), for example, jointly account for around 77 per cent of small electricity retail customers and 86 per cent of small gas retail customers (figure 7.4). The principal difference between the two sectors is that niche players have greater penetration in electricity markets compared with gas.

Figure 7.4

Electricity and gas retail market share (small customers)—Victoria and South Australia, 30 June 2008



Sources: ESC (Victoria), *Energy retailers: comparative performance report—customer service 2007–08*, Melbourne, December 2008; ESCOSA (South Australia), *Annual performance report: performance of South Australian energy retail market 2007–08*, Adelaide, November 2008.

14 ERA (Western Australia), *2007–08 Annual performance report—electricity retailers*, Perth, January 2008, p. 2.

15 In the ACT, the host retailer in electricity and gas—ActewAGL Retail—also offers contracts that 'bundle' electricity and gas retail services with telecommunications services.

Several factors have driven retail convergence, including business cost savings and convenience for customers. At the same time, convergence can create hurdles for new entrants—especially small players—that may need to deal with different market arrangements and different risks in the provision of electricity and gas services.

7.2.2 Vertical integration in the electricity sector

In the 1990s governments introduced reforms to structurally separate the power supply industry into generation, transmission, distribution and retail businesses. However, some links among different sectors of the power supply industry remain. In particular, the New South Wales, Queensland, Tasmanian, Western Australian and Northern Territory governments own joint distribution-retail businesses (although Ergon Energy in Queensland is restricted from competing in the retail market). The Western Australian Government owns Horizon Power, which is an integrated service provider. The ACT Government has ownership interests in both the host retailer of electricity and gas, and the electricity and gas distributor. Where links exist between retail and network sectors, regulators apply ring-fencing arrangements to ensure operational separation of the businesses.

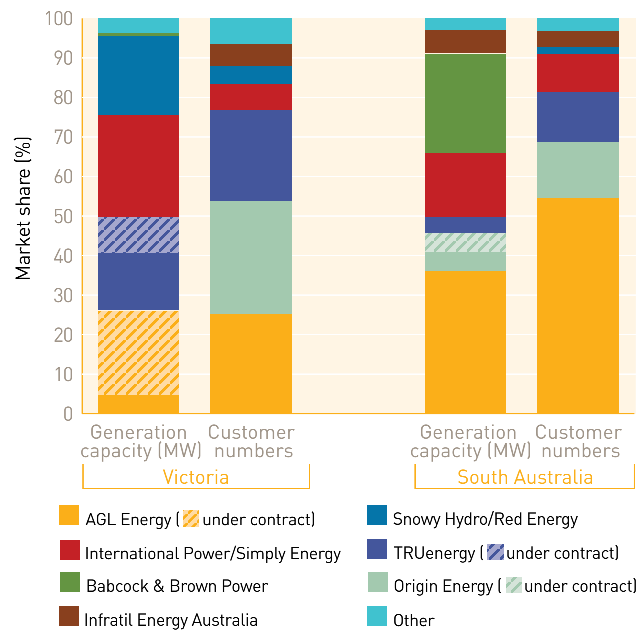
There is also a continuing trend towards vertical integration of privately owned electricity retailers and generators. Vertical integration provides a means for retailers and generators to manage the risk of price volatility in the electricity spot market. If wholesale prices rise, then the retailer can balance the increased cost against higher generator earnings.[16]

Figure 7.5 compares generation and retail market shares in Victoria and South Australia in 2008. Two of the three major retailers—AGL Energy and TRUenergy—have significant generation interests. In July 2007 AGL Energy and TRUenergy completed a generator swap in South Australia that moved the capacity of each business into closer alignment with their retail loads. Origin Energy has limited generation capability but is developing new capacity. In addition, major generator International Power operates a retail business (trading as Simply Energy) that has achieved significant penetration in the South Australian market.

There has also been vertical integration in the public electricity sector. Snowy Hydro owns Red Energy, which has acquired some market share in Victoria and South Australia. In September 2008 Hydro Tasmania acquired a controlling interest in the small private retailer Momentum Energy, with a move to full ownership intended in 2010.

Figure 7.5

Market share in the Victorian and South Australian retail and generation sectors, 2008



Notes:

The figures must be interpreted with caution because market shares in each sector are based on different variables: retail shares relate to small customer numbers, while generation shares relate to capacity.

In Victoria, TRUenergy holds a long term hedge contract with Ecogen Energy (owned by Industry Funds Management).

In South Australia, Origin Energy bids in the facility at Osborne power station (owned by ATCO Power and Origin Energy).

The chart represents the generation capacity of majority shareholders only.

Sources: ESC (Victoria), *Energy retailers: comparative performance report—customer service 2007–08*, Melbourne, December 2008; ESCOSA (South Australia), *Annual performance report: performance of South Australian energy retail market 2007–08*, Adelaide, November 2008 (customer numbers); AEMO (generation capacity and ownership).

16 There has been debate as to whether this form of ownership consolidation might, in some contexts, pose a barrier to entry for new entrant retailers. See, for example, Energy Reform Implementation Group, *Energy reform: the way forward for Australia*, Report to COAG, Canberra, January 2007, pp. 125–6.

7.3 Retail competition

While most jurisdictions have introduced or are introducing FRC, a competitive market can take time to develop. As a transitional measure, most jurisdictions require host retailers to offer to supply electricity services under a regulated standing offer (or default) contract (see section 7.4.1). Standing offer contracts cover minimum service conditions and information requirements, and may include regulated price caps or prices oversight.

At July 2009 all jurisdictions except Victoria applied some form of price cap regulation.[17] Australian governments have agreed to review the continued use of retail price caps and to remove them where effective competition can be demonstrated.[18] The AEMC is assessing the effectiveness of retail competition in each jurisdiction to advise on the appropriate time to remove retail price caps.[19] The relevant state or territory government makes the final decision on this matter. Box 7.1 summarises progress with the outcomes of reviews.

Box 7.1 Retail competition reviews

The Australian Energy Market Commission (AEMC) in February 2008 completed a review of the effectiveness of competition in Victoria's electricity and gas retail markets. It completed a similar review for South Australia in December 2008. Reviews are planned for the ACT in 2010, New South Wales in 2011, Queensland in 2012 and Tasmania in 2013 if full retail contestability has been introduced in that jurisdiction by that time.

The AEMC applies the following criteria to assess the effectiveness of retail competition:

- independent rivalry within the market
- the ability of suppliers to enter the market
- exercise of market choice by customers
- differentiated products and services
- prices and profit margins
- customer switching behaviour.

Victoria

The AEMC review of the Victorian electricity and gas retail markets found competition is effective in both markets.[20] In response to the review, the Victorian Government removed retail price caps on 1 January 2009. The legislation included provisions for the Essential Services Commission of Victoria (ESC) to monitor and report on retail prices. Retailers are also required to publish a range of their offers, to help consumers compare energy prices.

The removal of retail price regulation does not affect other obligations on retailers, including the obligation to supply and the consumer protection framework.[21] The Victorian Government retains a reserve power to re-instate retail price regulation if competition is found to no longer be effective.

South Australia

The AEMC found competition was effective for small electricity and gas customers in South Australia, but more intense in electricity than in gas.[22] It outlined options to phase out retail price regulation in South Australia. These options include a price monitoring and reporting regime to support the competitive market, and the retention of statutory reserve powers to re-introduce price regulation if the level of competition declines.[23]

In April 2009 the South Australia Government stated it did not accept the AEMC's recommendations to remove retail price regulation in electricity and gas at this time. It was concerned that more than 30 per cent of small customers remain on standing contracts and that stakeholders had differing views on the effectiveness of competition.

17 See section 7.4.1 for details.

18 Australian Energy Market Agreement 2004 (as amended).

19 In Western Australia, the Economic Regulation Authority (ERA) is responsible for this task.

20 AEMC, *Review of the effectiveness of competition in electricity and gas retail markets in Victoria—first final report*, Sydney, December 2007.

21 ESC (Victoria), 'Energy customers shop around for retail offers', Media release, 18 December 2008.

22 AEMC, *Review of the effectiveness of competition in electricity and gas retail markets in South Australia—first final report*, Sydney, September 2008, p. 19.

23 AEMC, *Review of the effectiveness of competition in electricity and gas retail markets in South Australia—second final report*, Sydney, December 2008.

The remainder of this section provides a sample of public data that may be relevant for assessing the effectiveness of retail competition in Australia. In particular, it sets out data on the diversity of price and product offerings of retailers; the exercise of market choice by customers, including switching behaviour; and customer perceptions of competition. This section also considers regulated prices and retail profit margins. Elsewhere, this chapter touches on other barometers of competition—for example, section 7.1 considers new entry.

The information provided here does not seek to draw conclusions. The AER is not assessing or commenting on the effectiveness of retail competition in any jurisdiction.

7.3.1 Price and non-price diversity of retail offers

There is evidence of retail price diversity in electricity markets that have introduced FRC (box 7.2). In particular, both host and new entrant retailers tend to offer market contracts at discounts against the 'default' regulated terms and conditions.

Some price diversity is associated with product differentiation—for example, retailers might offer a choice of standard products, green products, 'dual fuel' contracts (for gas and electricity) and retail packages that bundle electricity and gas services with other services such as telecommunications, each with different price structures.[24]

Some product offerings bundle energy services with inducements such as customer loyalty bonuses, awards programs, free subscriptions and prizes. Discounts and other offers tend to vary depending on the length of a contract. Some retail products offer additional discounts for prompt payment of bills or direct debit bill payments. Many contracts carry a severance fee, however, for early withdrawal.

The variety of discounts and non-price inducements makes direct price comparisons difficult. Further, the transparency of price offerings varies. Some retailers publish details of their products and prices, while others require a customer to fill out online forms or arrange a consultation. Victorian and South Australian retailers are required to publish product information statements on their websites. Additionally, the Queensland, South Australian and Victorian regulators and a number of other entities operate websites that allow customers to compare their current electricity and gas retail contracts with available market offers.

The Australian Consumer Association has launched a website—CHOICEswitch—that allows customers to compare energy retail offers. Box 7.2 draws on the website to comment on the diversity of price and product offerings to small customers in Brisbane, Sydney, Melbourne, Adelaide and Canberra. The price offers noted in box 7.2 are not directly comparable across jurisdictions, because the underlying product structures may not be identical.

For further information on retail prices, see section 7.4.

7.3.2 Customer switching

The rate at which customers switch their supply arrangements indicates customer participation in the market. While switching (or churn) rates can also indicate competitive activity, they must be interpreted with care. Switching is sometimes high during the early stages of market development, when customers are first able to exercise choice. Switching rates sometimes stabilise even as a market acquires more depth. Similarly, they may be low in a very competitive market if retailers are delivering good quality service that gives customers no reason to switch.

24 In the ACT, the host retailer in electricity and gas—ActewAGL Retail—offers discounts on electricity services if the customer elects to 'bundle' electricity retail services with gas and telecommunications services.

Box 7.2 Price and product diversity in the small customer market

The CHOICEswitch website (www.choiceswitch.com.au) provides an online estimator service that allows consumers to make quick comparisons of electricity and gas retail offers available in their area. The website also provides information on the terms, conditions and other benefits of each offer.

Table 7.5 draws on data available on the CHOICEswitch website to set out the estimated price offerings in May 2009 for customers in selected suburban postcodes in Brisbane, Sydney, Melbourne, Adelaide and Canberra using 6500 kilowatt hours (kWh) a year, based on peak use. The offers were only for the postcodes selected and might not have been available to all customers. The data include all financial discounts and bonuses available under each offer but exclude non-financial gifts such as magazine subscriptions, gift cards and movie tickets.

The data indicate some price and product diversity in all of the retail markets, with a price spread of $582 (Melbourne) to $864 (Canberra).[25] Most plans included additional financial discounts and bonuses, with prompt payment being the most common condition to attract a discount. Other financial incentives offered by some retailers included joining and loyalty bonuses.

Some of the offers with larger discounts were provided under a fixed term contract that attracts exit fees for early termination. Retail offers in the upper price range generally provided higher levels of accredited renewable energy (GreenPower). For offers with 100 per cent GreenPower, some retailers allowed customers to choose solar or wind power as the source of their energy.

In the capital cities where retail prices are regulated (Brisbane, Sydney, Adelaide and Canberra) most retailers offered products that provided a discount off the regulated price. Retailers in Adelaide offered the largest discount off the regulated price (up to $220), compared with a discount of up to $95 in Brisbane, $87 in Sydney and $19 in Canberra.

25 Very large price spreads may reflect product differentiation. Some premium priced products have high proportions of accredited green power. Some ActewAGL products, for example, allow customers to purchase more GreenPower than their household would use.

Jessica Shapiro (Fairfaxphotos)

Table 7.5 Electricity retail price offers for a customer using 6500 kWh per year in each capital city, May 2009

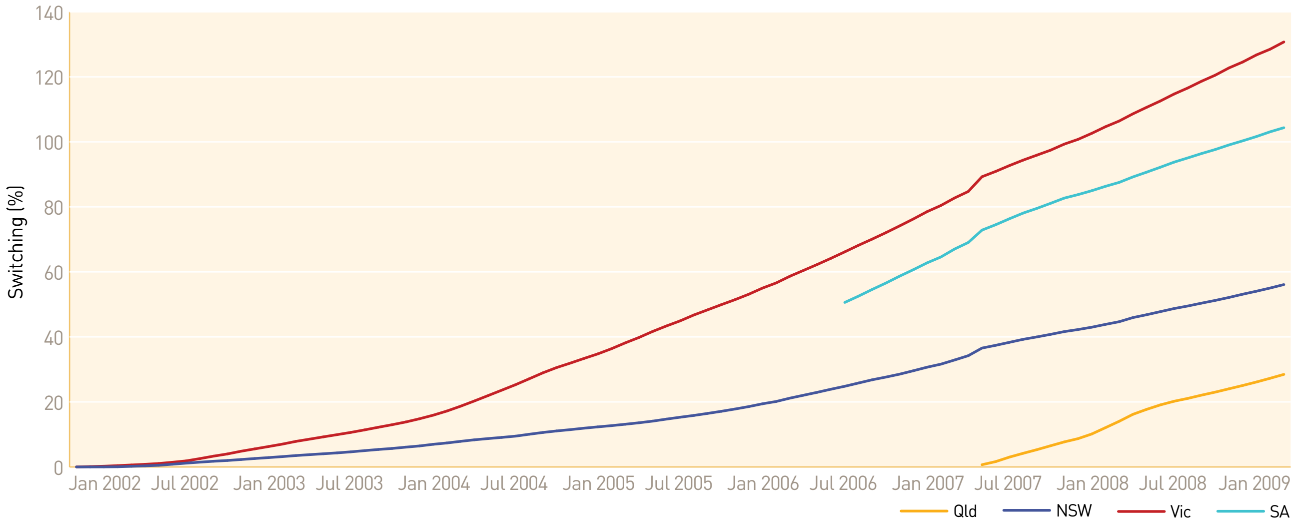
RETAILER	NO. OF PRODUCTS	ANNUAL COST (INCLUDING DISCOUNTS AND FINANCIAL BONUSES) 1000 1100 1200 1300 1400 1500 1600 1700 1800 1900 2000 2100	DISCOUNTS AND BONUSES INCLUDED IN ANNUAL COST: Pay-on-time bonus	Loyalty bonus	Sign-up bonus	CONTRACT TERM: Fixed term	Exit fees	GREEN POWER?
BRISBANE (POSTCODE 4032)								
Regulated price (AGL Energy)								
AGL Energy	7					●	●	●
EnergyAustralia	4					●	●	●
Ergon Energy	1							
Integral Energy	6					●	●	●
Jackgreen	4		●				●	●
Origin Energy	12					●	●	●
Queensland Electricity	1							
TRUenergy	13		●			●	●	●
SYDNEY (POSTCODE 2148)								
Regulated price (Integral Energy)								
AGL Energy	6					●	●	●
EnergyAustralia	3							●
Integral Energy	11					●	●	●
Jackgreen	4		●				●	●
Origin Energy	12					●	●	●
TRUenergy	13		●			●	●	●
MELBOURNE (POSTCODE 3079)								
AGL Energy	6					●	●	●
Australian Power & Gas	7		●		●			●
Click Energy	4		●		●	●	●	
Country Energy	4				●	●	●	●
EnergyAustralia	9				●			●
Jackgreen	7		●			●	●	●
Neighbourhood Energy	5		●					●
Origin Energy	12					●	●	●
Red Energy	5		●	●		●	●	●
Simply Energy	3		●	●				●
TRUenergy	13		●			●	●	●
Victoria Electricity	4		●			●	●	●
ADELAIDE (POSTCODE 5007)								
Regulated price (AGL Energy)								
AGL Energy	6					●	●	●
Jackgreen	4		●				●	●
Origin Energy	12					●	●	●
Red Energy	2		●	●		●	●	●
Simply Energy	3		●	●				●
South Australia Electricity	1							
TRUenergy	13		●			●	●	●
CANBERRA (POSTCODE 2616)								
Regulated price (ActewAGL)								
ActewAGL	20							●

Note: The offers were only for standalone electricity products in the postcodes selected and might not have been available to all customers. The data include all financial discounts and bonuses available under each offer. Green power refers to renewable energy accredited under the Australian Government's GreenPower scheme.

Source: CHOICEswitch energy comparison website, viewed 22 May 2009, www.choiceswitch.com.au.

Figure 7.6

Cumulative monthly customer switching of retailers as a percentage of small customers, January 2002 to June 2009



Note: There are no comparable public data for South Australia prior to June 2006.

Sources: see table 7.6.

Table 7.6 Small customers switching retailers, 2009

INDICATOR	QUEENSLAND	NEW SOUTH WALES	VICTORIA	SOUTH AUSTRALIA
Percentage of small customers that changed retailer during 2008–09 (%)	14.6	11.5	25.7	16.0
Customer switches as a percentage of the small customer base from start of FRC to June 2009 (cumulative) (%)	28.5	56.1	130.7	104.4

FRC, full retail contestability.

Notes:

If a customer switches to a number of retailers in succession, then each move counts as a separate switch. Cumulative switching rates may thus exceed 100 per cent.

The customer base is estimated at 30 June 2009.

Sources: Customer switches: AEMO, MSATS transfer data to June 2009; customer numbers: IPART (New South Wales), *NSW electricity information paper—electricity retail businesses' performance against customer service indicators*, Sydney, March 2009; ESCOSA (South Australia), *2007–08 Annual performance report: performance of South Australian energy retail market*, Adelaide, November 2008; ESC (Victoria), *Energy retailers: comparative performance report—customer service 2007–08*, Melbourne, December 2008; ESCOSA (South Australia), *Annual performance report: performance of South Australian energy retail market 2007–08*, Adelaide, November 2008; QCA (Queensland), *Market and non-market customers, December quarter 2008*, Brisbane, April 2009.

The Australian Energy Market Operator (AEMO) publishes churn data measuring the number of customer switches from one retailer to another.[26] The data are available for New South Wales and Victoria from the introduction of FRC in 2002, for South Australia from October 2006 and for Queensland from July 2007.

Table 7.6 and figure 7.6 set out gross switching data—that is, the total number of customer switches in a period, including switches from a host retailer to a new entrant, switches from new entrants back to a host retailer, and switches from one new entrant to another. If a customer switches to a number of retailers in succession, each move counts as a separate switch. Cumulative switching rates may thus exceed 100 per cent.

26 The National Electricity Market Management Company (NEMMCO) published the data until 30 June 2009.

Table 7.7 Customer transfers to market contracts

JURISDICTION	DATE	CUSTOMERS ON MARKET CONTRACTS (% OF CUSTOMER BASE)
Queensland	31 March 2009	44.3% of small customers[1]
Victoria	30 June 2008	54% of electricity and gas customers
South Australia	30 June 2008	69% of residential customers (24% with the host retailer and 49% with new entrants)
		52% of small business customers (21% with the host retailer and 31% with new entrants)
		68% of residential and small business customers (averaged)
ACT	30 June 2008	21% of all customers

1. Small customers in Queensland include residential and small business customers.

Sources: ESC (Victoria), *Energy retailers: comparative performance report—customer service 2007–08*, Melbourne, December 2008; QCA (Queensland), *Market and non-market customers as at 30 September 2008*, Brisbane, September 2008; ESCOSA (South Australia), *2007–08 Annual performance report: performance of South Australian energy retail market 2007–08*, Adelaide, November 2008, pp. 22–3; ICRC (ACT) *Draft decision: retail prices for non-contestable electricity customers, 2009–2010*, Canberra, April 2009.

The data do not include customers that switch from a default arrangement to a market contract with their existing retailer. The data may thus understate the true extent of competitive activity by not accounting for the efforts of host retailers to retain market share.

Table 7.6 illustrates that switching activity continued strongly in Victoria (and to a lesser extent South Australia and Queensland) throughout 2008–09. A recent survey by *Choice* magazine found Victorian customers are more likely than interstate customers to be approached by door-to-door sales people and telemarketers offering a range of energy services.[27] New South Wales continues to have a switching rate below the other states.

Switches to market contracts

While AEMO reports on customer switching between retailers, an alternative churn indicator is customer switching from regulated 'default' contracts to market contracts. South Australia and Queensland publish these data periodically, while New South Wales, the ACT and Victoria do so irregularly.

Table 7.7 summarises the available data on switches to market contracts. The data are not directly comparable across jurisdictions because the data collection methods and periods covered differ.

Table 7.7 indicates that a significant number of customers are moving from standing offer contracts to market contracts with their host retailer. South Australia has reported relatively high rates of customer switching to market contracts, compared with rates in the other states. Victoria has also reported relatively high rates of customer transfers to market contracts, but the data include transfers in both the electricity and gas retail markets.

7.3.3 Customer perceptions of competition

A number of jurisdictions undertake occasional surveys on customer perceptions of retail competition. Issues covered include:

> customers' awareness of their ability to choose a retailer
> customer approaches to retailers about taking out a market contract
> retail offers received by customers
> customer understanding of retail offers.

Table 7.8 summarises survey data on customer perceptions of retail competition. The data are not directly comparable across jurisdictions because the data collection methods, periods covered and regions surveyed differ. The surveys suggest customer awareness of retail choice is high and rising over time. While it remains unusual for customers to approach retailers, retailer approaches to customers have steadily risen.

27 *Choice* magazine, 'Power play', March 2009, p. 14. [Reprinted from 'Power play', March 2009 *Choice* magazine, with the permission of the Australian Consumer Association.]

Table 7.8 Residential customer perceptions of competition

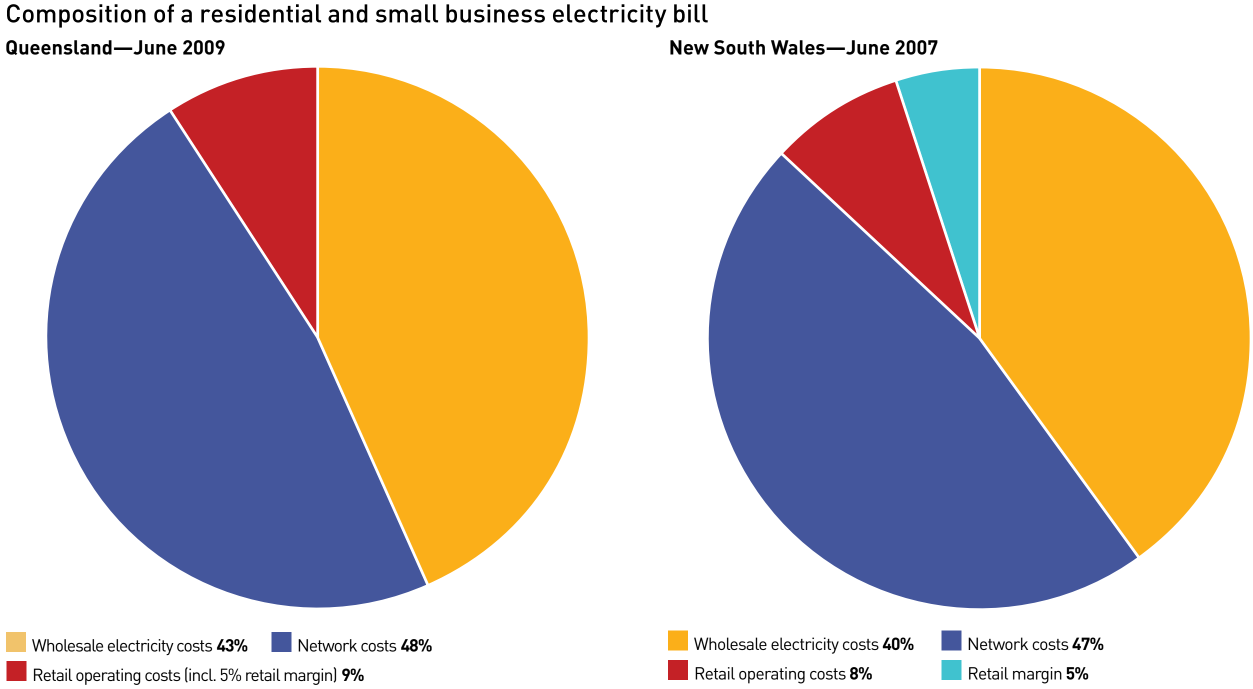
INDICATOR	NEW SOUTH WALES[1] Sydney	NEW SOUTH WALES[1] Hunter region	VICTORIA		SOUTH AUSTRALIA	
	2003	2008	2002	2007	2003	2008
Customers aware of choice (%)	74	90	n/a	94	62	82
Customers receiving at least one retail offer[2] (%)	27	53	17	73	5	68
Customers approaching retailers about taking out market contracts (%)	n/a	n/a	3	10	3	10

n/a, not available.

1. New South Wales data in 2003 are based on a household survey conducted in Sydney, while the 2008 data are based on a similar household survey conducted in the Hunter region.
2. In New South Wales, the figures exclude customers approached by their current retailer to switch to a market contract.

Sources: South Australia: McGregor Tan Research, *Monitoring the development of energy retail competition—residents*, Report prepared for ESCOSA, Adelaide, February 2006, November 2003; McGregor Tan Research, *Review of effectiveness of competition in electricity and gas retail markets*, Report prepared for the AEMC, Adelaide, June 2008; Victoria: The Wallis Group, *Review of competition in the gas and electricity retail markets—consumer survey*, Report prepared for the AEMC, Melbourne, August 2007; New South Wales: IPART, *Electricity, gas and water research paper—residential energy and water use in the Hunter, Gosford and Wyong*, Sydney, December 2008; IPART, *Residential energy and water use in Sydney, the Blue Mountains and Illawarra—results from the 2006 household survey*, Sydney, November 2007.

Figure 7.7
Composition of a residential and small business electricity bill



Note: Figures represent the composition of estimated costs for an electricity retailer.

Sources: IPART (New South Wales), *Regulated electricity tariffs and charges for customers 2007 to 2010—electricity final report and final determination*, Sydney, June 2007, p. 2; QCA (Queensland), *2009–10 Benchmark retail cost index, final decision,* Brisbane, June 2009, p. 54.

7.4 Retail prices

Retail customers pay a single price for a bundled electricity product made up of electricity, transport through the transmission and distribution networks, and retail services. Data on the underlying composition of retail prices are not widely available. Figure 7.7 provides indicative data for residential customers in New South Wales and residential and small business customers in Queensland based on historical information. The charts indicate that wholesale and network costs account for the bulk of retail prices. Retail operating costs (including retail margins) account for around 13 per cent of retail prices in New South Wales and 9 per cent in Queensland.

7.4.1 Regulation of retail prices

At July 2009 all jurisdictions except Victoria applied retail price regulation to small customers. Typically, host retailers must offer to sell electricity at default prices based on some form of regulated price cap or oversight. Small customers may request a standing offer contract —with default prices—from the host retailer or choose an unregulated market contract from a licensed retailer.

Price cap regulation was intended as a transitional measure during the development of retail markets. To allow efficient signals for investment and consumption, governments are moving towards removing retail price caps. As noted, the AEMC (and the Economic Regulation Authority in Western Australia) is responsible for reviewing the effectiveness of competition in electricity and gas retail markets to determine an appropriate time to remove retail price caps in each jurisdiction (box 7.1).

In setting default tariffs, jurisdictions consider energy purchase costs, network charges, retailer operating costs and a retail margin.

The approach varies across jurisdictions:

- The Queensland regulator, the Queensland Competition Authority (QCA), uses a benchmark retail cost index method to calculate annual adjustments in regulated prices for small customers that do not enter a market contract on changes in benchmark costs. In June 2009 the Queensland Government directed the QCA to review the method and prices to determine whether current price levels promote competition, allow real electricity costs to be fully recovered from south east Queensland consumers, and account for government environmental obligations.[28] The QCA will review alternative methods for setting prices and price structures that may assist in managing peak electricity demand and encourage more efficient electricity use.
- The New South Wales regulator, the Independent Pricing and Regulatory Tribunal (IPART), sets a retail price cap for small customers that do not enter a market contract. IPART noted in its review of retail prices for 2007–10 that the New South Wales Government aimed to reduce customer reliance on regulated prices and had directed IPART to ensure regulated tariffs are cost-reflective by June 2010.[29]
- The Victorian Government removed retail price caps for small businesses users on 1 January 2008[30] and for residential customers on 1 January 2009.[31]
- The South Australian regulator, the Essential Services Commission of South Australia (ESCOSA), regulates default prices for small customers. In 2007 ESCOSA made a determination on default prices for three years commencing on 1 January 2008.
- In Western Australia, electricity retail prices for non-contestable customers are regulated under statutory requirements and set out in bylaws. All non-contestable customers are entitled to a uniform price regardless of their geographic location. Customers in major population centres in the state's south west subsidise regional customers through the Tariff Equalisation Fund.[32]

28 QCA, Letter from Minister for Natural Resources, Mines and Energy and Minister for Trade, and the Ministers' Direction Notice for the review, Brisbane, 24 June 2009.

29 IPART (New South Wales), *Regulated electricity tariffs and charges for customers 2007 to 2010—electricity final report and final determination*, Sydney, June 2007, p. 2.

30 Peter Batchelor (Minister for Energy and Resources, Victoria), 'Better energy prices available to small businesses', Media release, 8 November 2007.

31 Department of Primary Industries (Victoria), 'Energy efficiency', viewed 1 May 2009, www.dpi.vic.gov.au/energy.

32 Office of Energy, *Electricity retail market review—issues paper*, Perth, December 2007, p. 7.

Table 7.9 Recent regulatory decisions—electricity retail prices

JURISDICTION	PERIOD	RETAILERS	INCREASE IN REGULATED RETAIL PRICE	MECHANISM FOR CHANGES IN REGULATED PRICE	RETAIL MARGIN
Queensland	1 July 2009 to 30 June 2010	All licensed retailers	Net additional increase of 3.68% for 2008–09 (applying from 1 July 2009) and 11.82% for 2009–10	Prices are adjusted annually in accordance with a benchmark retail cost index.	5% of total revenue
New South Wales	1 July 2007 to 30 June 2010	EnergyAustralia Integral Energy Country Energy	CPI + 4.1% CPI + 4.9% CPI + 3.7% (annual adjustments)	Electricity purchase costs are annually reviewed. The retail price path will be adjusted if the review finds forecast electricity purchase costs differ by more than 10% from the costs used to set the price path. Retailers are also required to pass on network price increases. In 2009 IPART made a determination to increase a typical bill of EnergyAustralia (by 21.7%), Integral Energy (by 21.1%) and Country Energy (by 17.9%), due to rising wholesale and network costs.	5% of EBITDA
South Australia	1 January 2008 to 31 December 2010	AGL Energy	6.8% in 1 Jan 08 to 30 June 2008; CPI-only increase to July 2011	There is no provision to adjust the price path due to changes in electricity purchase costs. However, the price determination can be re-opened if a fundamental basis of the determination has been undermined.	10% of controllable costs (equivalent to about 5% of sales revenue)
Western Australia	1 April 2009 1 July 2009	Synergy and Horizon Power	10.0% 15.0%	Government decision is to be implemented through bylaws. Further price rises will be phased in over six to eight years (after 30 June 2010).	n/a
Tasmania	1 January 2008 to 30 June 2010	Aurora Energy	Average 16.0% in 1 Jan 2008 to 30 June 2008, and estimated average increases of 4.0% in 2008–09 and 3.8% in 2009–10 respectively	There is no provision to adjust the price path due to changes in electricity purchase costs. Regulations set out the average price the regulator is to assume for each period. The regulator has limited discretion to re-open a determination in the event of an unforeseen material change. Provision was made to adjust for certain pass-through costs, including transmission and distribution costs.	3% of sales revenue
ACT	1 July 2009 to 30 June 2010	ActewAGL Retail	6.42%	Annual price determination. There are no automatic cost adjustments, but the ICRC Act allows for variations to the price direction to occur, if the circumstances change from those that existed when the decision was finalised.	5% of sales revenue

n/a, not available; EBITDA, earnings before interest, tax, depreciation and amortisation.

Sources: QCA (Queensland), *2009-10 Benchmark retail cost index, final decision*, June 2009, Brisbane, p. i; IPART (New South Wales), *Regulated electricity retail tariffs and charges for customers 2007 to 2010: electricity final report and final determination*, Sydney, June 2007; ESCOSA (South Australia), *2007 Review of retail electricity price path: final inquiry report and price determination*, Adelaide, November 2007; OTTER (Tasmania), *Investigation of prices for electricity distribution services and retail tariffs on mainland Tasmania: final report and proposed maximum prices*, Hobart, September 2007; ICRC (ACT), *Final decision—retail prices for non-contestable electricity customers 2009–2010*, Canberra, June 2009; Peter Collier (Minister for Energy, Western Australia), 'State Government announces increases in tariff arrangements', Media release, 23 February 2009.

- When requested by the ACT Government, the ACT regulator, the Independent Competition and Regulatory Commission (ICRC), determines the maximum prices for small customers on a standing offer contract. The regulator annually adjusts the regulated tariff to reflect changes in benchmark costs.

Table 7.9 compares recent movements in regulated default prices and retail margins under regulatory or government decisions. The decisions relate to the supply of electricity by host retailers to customers on standing offer contracts. The chart omits Victoria, which no longer regulates retail prices.

Different price outcomes across the jurisdictions reflect a range of factors, so must be interpreted with care. In particular, the operating environments of retail businesses differ. The degree of retailer exposure to wholesale costs depends on a variety of factors, including the nature and shape of a retailer's load, the extent of hedging in financial markets to protect against price volatility, and the strike price of financial contracts. Some retailers have vertical relationships with generators to cushion the impact of volatile wholesale costs.

Regulated default prices tended to be relatively stable in 2008–09. This followed significant price rises in 2007–08, largely due to the impact of the drought on wholesale electricity prices (see chapter 2). However, prices are set to rise again in some jurisdictions:

- In May 2009 IPART announced that a typical retail bill in New South Wales would rise by 17.9–21.9 per cent in 2009–10 due to network price increases and higher wholesale costs.[33]
- In June 2009 the QCA announced that regulated retail prices for 2009–10 would increase by 11.82 per cent. Following an appeal by Origin Energy and AGL Energy, the QCA announced an additional increase in regulated prices for 2008–09 of 3.68 per cent. This additional increase applied from 1 July 2009, resulting in a total increase in regulated retail prices for 2009–10 of 15.5 per cent.[34]
- The ICRC announced that retail prices in the ACT will increase by up to 6.42 per cent in 2009–10 due to higher distribution costs.[35]
- In Western Australia, the Office of Energy recommended in 2008 that retail prices increase by 52 per cent. The Western Australian Government rejected this recommendation and announced that residential prices will increase by 10 per cent on 1 April 2009 and a further 15 per cent on 1 July 2009.[36]

7.4.2 Retail price outcomes

While retail price outcomes are critical to consumers, the interpretation of retail price movements is not straightforward. Trends in retail prices may reflect movements in the cost of any one or a combination of underlying components: wholesale electricity prices, transmission and distribution charges, and/or retail operating costs and margins.

Care must be taken when interpreting retail price trends in deregulated markets. While competition tends to deliver efficient outcomes, it may give a counter-intuitive outcome of higher prices—especially in the early stages of competition. In particular:

- governments and other customers (usually business customers) historically subsidised energy retail prices for some residential customers. A competitive market will unwind cross-subsidies, which may lead to price rises for some customer groups.
- some regulated energy prices were traditionally at levels that would have been too low to attract competitive new entrants. It may be necessary for retail prices to rise to create sufficient 'head room' for new entry.

33 IPART (New South Wales), *Market-based electricity purchase cost allowance—2009 review, regulated electricity retail tariffs and changes for small customers 2007–2010*, Sydney, May 2009, p. 2.

34 QCA (Queensland), *2009–10 Benchmark retail cost index, final decision*, Brisbane, June 2009, p. i.

35 ICRC (ACT), *Final decision—retail prices for non-contestable electricity customers 2009–2010*, Canberra, June 2009, p. 5.

36 Peter Collier (Minister for Energy), 'State Government announces increases in tariff arrangements', Media release, 23 February 2009.

Figure 7.8

Retail electricity price index (inflation adjusted)—Australian capital cities, June 1991 to March 2009

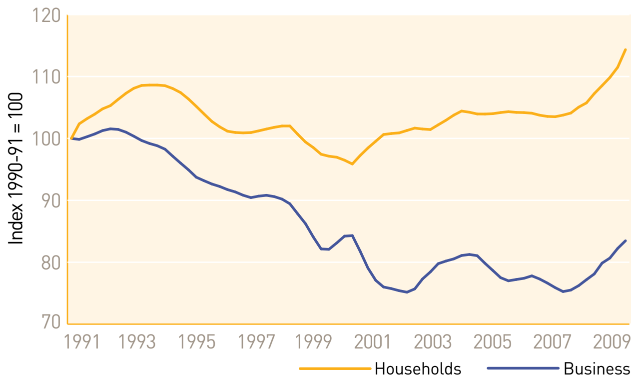
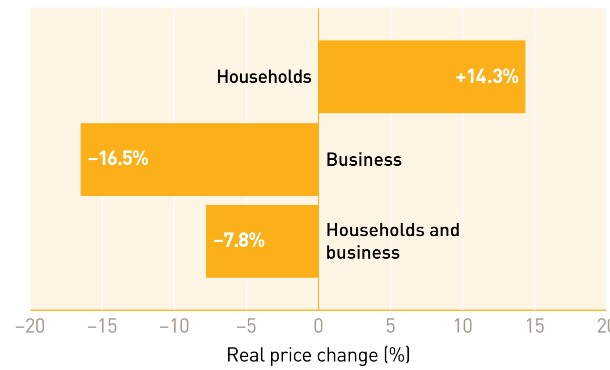


Figure 7.9

Change in the real price of electricity—Australia, June 1991 to March 2009



Note: The household index is based on the CPI for household electricity, deflated by the CPI series for all groups. The business index is based on the producer price index for electricity supply in 'Materials used in Manufacturing Industries', deflated by the CPI series for all groups.

Sources: ABS, *Consumer price index* and *Producer price index, March quarter 2009*, cat. nos 6401.0 and 6427.0, Canberra, 2009.

Sources of price data

There is little systematic publication of the actual prices paid by electricity retail customers. At the state level:

> jurisdictions that retain price caps publish schedules of regulated prices. The schedules are a useful guide to retail prices, but their relevance as a price barometer is reduced as more customers transfer to market contracts.

> retailers are not required to publish the prices struck through market contracts with customers, although some states require the publication of market offers

> the Victorian and South Australian regulators (the ESC and ESCOSA) publish annual data on retail prices

> the ESC, ESCOSA and the Queensland regulator (QCA) provide estimator services on their websites, allowing consumers to compare the price offerings of retailers

> the CHOICEswitch website provides a comparison and switching service, to help consumers compare electricity and gas offers (box 7.2). Other price comparison websites also exist.

Consumer price index and producer price index

The consumer price index (CPI) and producer price index, published by the Australian Bureau of Statistics, track movements in household and business electricity prices.[37] The indexes are based on surveys of the prices paid by households and businesses, so reflect a mix of regulated and market prices.

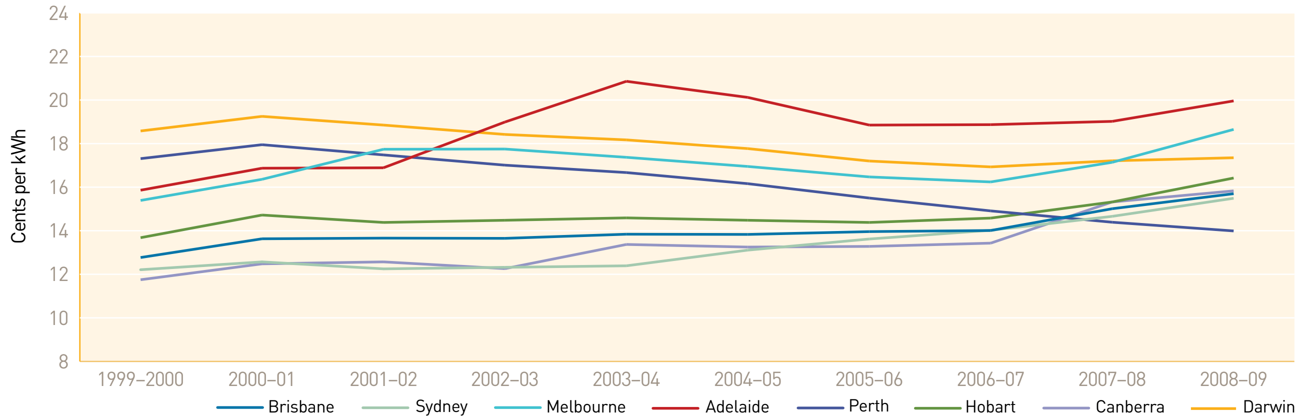
Figure 7.8 tracks real electricity price movements for households and business customers. There is some volatility in the data for business customers, given that large energy users are exposed to price volatility in the wholesale and contract markets for electricity (see chapters 2 and 3). In most jurisdictions, residential prices are at least partly shielded from volatility by price cap regulation and retailers' hedging arrangements.

Since 1991 real household prices have risen by 14.3 per cent, while business prices have fallen by 16.5 per cent (figure 7.9). In part, these changes reflect the unwinding of cross-subsidies from business to household customers that began in the 1990s. While business prices have fallen substantially since 1991, they have risen since 2007, mainly as a result of rising wholesale electricity costs.

37 The producer price index series tracks input costs for manufacturers.

Figure 7.10

Estimated real electricity prices for households—Australian capital cities, July 1999 to March 2009



KWh, kilowatt hour.

Notes:

The prices are estimates based on extrapolating ESAA data published in 2004 using the CPI series for electricity and other household fuels for each capital city.

The 2008–09 data cover the three quarters to March 2009.

Sources: ABS, *Consumer price index, March quarter 2009*, cat no. 6401, Canberra, 2009; ESAA, *Electricity prices in Australia 2003–04*, Melbourne, 2003.

It is possible to estimate average retail prices for households by using the CPI to extrapolate from historical data published by the Energy Supply Association of Australia (ESAA).[38] Figure 7.10 estimates real electricity prices for households in Brisbane, Sydney, Melbourne, Adelaide, Perth, Hobart, Canberra and Darwin since 1 July 1999. Price variations across the cities reflect multiple factors, including differences in generation and network costs, industry scale, historical cross-subsidies, differences in regulatory arrangements and different stages of electricity reform implementation.

From 2001 to 2009, real electricity prices in Perth trended downwards while Melbourne, Sydney and Canberra prices trended upwards. In Brisbane (where small customer prices remained fully regulated until 2007) and Hobart (where small customer prices are still fully regulated), real prices have remained relatively stable since 2001, but have trended higher since 2007. Price rebalancing to phase out cross-subsidies caused significant price rises in Melbourne and Adelaide early in the decade.

7.5 Quality of retail service

The jurisdictional regulators monitor and report on quality of service in the retail sector to enhance transparency and accountability, and to facilitate 'competition by comparison'.[39] In November 2000 the Utility Regulators Forum (URF) established the Steering Committee on National Regulatory Reporting Requirements. The committee developed a national framework in 2002 for electricity retailers to report against common criteria on service performance.[40] The steering committee amended the national framework and reporting template in 2007.[41] The criteria in the national framework address:

- access and affordability of services
- quality of customer service.

The measures apply to the small customer retail market.[42] All National Electricity Market (NEM) jurisdictions have adopted the national template but each jurisdiction applies its own implementation framework. In addition, jurisdictions have their own

38 The ESAA published annual data on retail electricity prices by customer category and region until 2004.

39 See, for example, ESC (Victoria), *Energy retailers: comparative performance report—customer service 2007–08*, Melbourne, December 2008.

40 URF, *National regulatory reporting for electricity distribution and retailing businesses, discussion paper*, Canberra, March 2002.

41 URF, *National energy retail performance indicators, final paper*, May 2007.

42 See footnote 2 for jurisdictional classifications of 'small customers'.

monitoring and reporting requirements. There are thus some differences in approach.

The service quality data published by jurisdictional regulators are derived from the reporting of individual retailers. The regulators annually consolidate and publish the data. The validity of any performance comparisons may be limited, however, given the differences in jurisdictions' approach. In particular, measurement systems, audit procedures and classifications may differ across jurisdictions and within the same jurisdiction over time. Similarly, regulatory procedures and practices differ—for example, the procedures that a retailer must follow before a customer can be disconnected.

7.5.1 Affordability and access indicators

With the introduction of retail contestability, governments have strengthened consumer protection arrangements, focusing on access and affordability issues. These protections are often given effect through regulated minimum standards regimes and codes.

Retailers provide options to help customers manage their bill payments. The URF's reporting template covers a number of affordability indicators, including rates of customer disconnections and reconnections. The rate of residential customer disconnections for failure to meet bill payments (figure 7.11) and the rate of disconnected residential customers who are reconnected within seven days (figure 7.12) are key affordability and access indicators.

In 2007–08 the rate of disconnections fell in New South Wales, Victoria, the ACT and Western Australia, but increased slightly in South Australia and Tasmania. The rates in that year were below 2003–04 rates in all jurisdictions with available data except Tasmania. A range of factors might have contributed to these outcomes. Difficulties with the implementation of a new billing system, for example, led to AGL Energy suspending customer disconnections in Victoria. As a result, AGL Energy's disconnection rate in 2007–08 was below its historical average, which might have affected Victoria's average disconnection rate.[43]

The rate at which disconnected residential customers are reconnected within seven days (figure 7.12) increased in Victoria in 2007–08, but fell in New South Wales, Western Australia, Tasmania and the ACT. South Australia recorded a slight decrease in its seven day reconnection rate. Rates in 2007–08 were below 2003–04 rates in all jurisdictions with available data.

7.5.2 Customer service indicators

Customers can seek to resolve service issues with energy retailers via a range of methods. First, they can raise complaints through the retailer's dispute resolution procedure. If further action is needed, they can refer complaints to the state energy ombudsman or an alternative dispute resolution body. Additionally, retail competition allows customers to transfer away from a business providing poor service.

Monitoring in this area includes:

- customer complaints—the degree to which a retailer's services meet customers' expectations
- telephone call management—the efficiency of a retailer's call centre service.

In 2007–08 the rate of customer complaints fell in New South Wales, but increased slightly in Victoria, South Australia, Western Australia and Tasmania. A significant increase occurred in the ACT (figure 7.13). The rate of customer complaints in Victoria has increased every year since 2003–04. The number of complaints that required a full investigation by the Electricity and Water Ombudsman of Victoria also increased (by 6 per cent) in 2007–08. AGL Energy experienced significant difficulties with a new billing system in December 2007, which might have resulted in a one-off increase in the complaints referred to the Ombudsman.[44]

43 ESC (Victoria), *Energy retailers: comparative performance report—customer service 2007–08*, Melbourne, December 2008, p. 26.

44 ESC (Victoria), *Energy retailers: comparative performance report—customer service 2007–08*, Melbourne, December 2008, p. 42.

The response times of retailer call centres improved in every jurisdiction for which data were available in 2007–08 (figure 7.14). Retailers in Western Australia recorded a significant improvement in prompt call answering times, up from 63 per cent in 2006–07 to 80 per cent in 2007–08.[45]

7.5.3 Consumer protection

Governments regulate aspects of the electricity retail market to protect consumers and ensure they have access to sufficient information to make informed decisions. Most jurisdictions require designated host retailers to provide electricity services under a standing offer or default contract to particular customers. Most impose this obligation on retailers on a geographic basis. Queensland, however, requires the financially responsible market participant—generally the current retailer—to offer default contracts for each property; obligations for new connections are imposed on a geographic basis.[46]

Default contracts cover minimum service conditions, billing and payment obligations, procedures for connections and disconnections, information disclosure and complaints handling. During the transition to effective competition, default contracts may also include some form of regulated price cap or prices oversight (see section 7.4.1).

Some jurisdictions have also established industry codes that govern the provision of electricity retail services to small customers, including those under market contracts. Industry codes cover consumer protection measures, including:

- minimum terms and conditions under which a retailer can provide electricity retail services
- standards for the marketing of energy services
- processes for the transfer of customers from one retailer to another.

Most jurisdictions have an energy ombudsman or an alternative dispute resolution body to whom consumers can refer a complaint they were unable to resolve directly with the retailer. In addition to general consumer protection measures, jurisdictions have introduced 'retailer of last resort' arrangements to ensure customers can transfer from a failed retailer to another retailer.

Community service obligations to particular customer groups (often, low income earners) are another form of consumer protection. Traditionally, the payments were often 'hidden' in subsidies and cross-subsidies between different customer groups, which distorted pricing and investment signals. As part of the energy reform process, the Ministerial Council on Energy developed the Energy Community Service Obligations National Framework to make community service obligations more transparent and fund them directly out of budgets rather than via cross-subsidies.

In April 2008 the Productivity Commission recommended establishing a national consumer protection regime for energy services and a single set of consumer protection requirements in all NEM jurisdictions confirming processes already in place to develop a National Energy Customer Framework.[47] The commission also recommended a more consistent approach to complaint handling and reporting processes by jurisdictional energy ombudsmen and, ultimately, the establishment of a national energy ombudsman.[48]

45 ERA (Western Australia), *2007–08 Annual performance report—electricity retailers*, Perth, March 2009, p. 18.

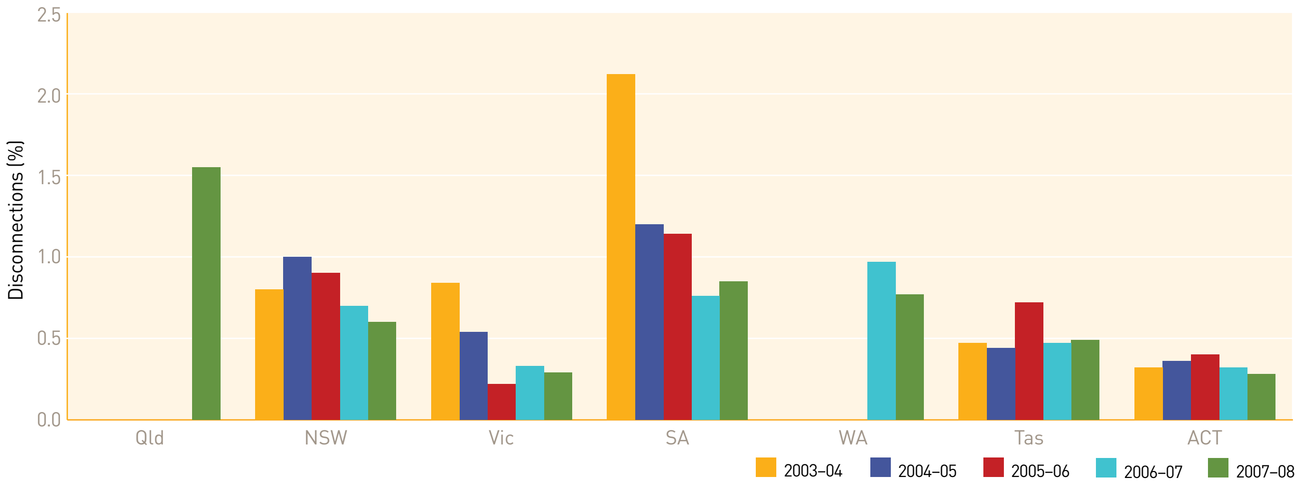
46 The AEMC, in its review of the effectiveness of the Victorian energy retail market, recommended Victoria move to a financially responsible market participant model. In response to this recommendation, Victoria made its local area model more consistent with the financially responsible market participant model.

47 Productivity Commission, *Inquiry report: review of Australia's consumer policy framework*, Canberra, April 2008, pp. 66–7.

48 Productivity Commission, *Inquiry report: review of Australia's consumer policy framework*, Canberra, April 2008, p. 71.

Figure 7.11

Electricity residential disconnections for failure to pay amount due, as a percentage of the small customer base



Notes:

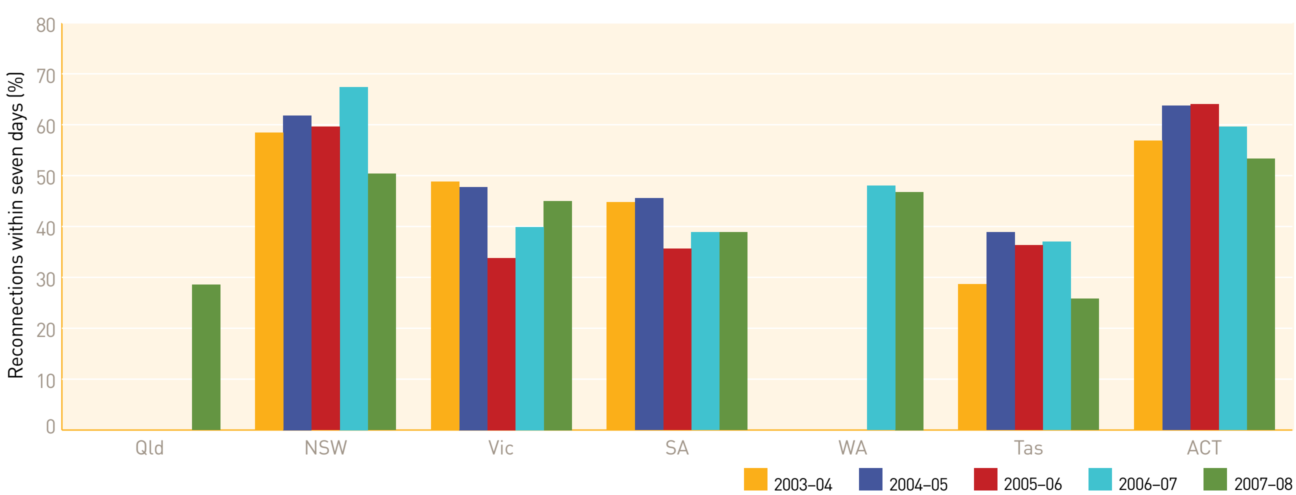
Data relate to outcomes for residential customers on a statewide basis. State regulators also publish outcomes for particular retailers and for business customers in their jurisdiction.

Queensland data are not available for all years. Western Australia commenced publication of these data in 2006–07.

Source: see figure 7.14.

Figure 7.12

Electricity residential reconnections within seven days, as a percentage of disconnected customers



Notes:

New South Wales data include all reconnections (not just within seven days of disconnection).

Queensland data are not available for all years. Western Australia commenced publication of these data in 2006–07.

Source: see figure 7.14.

Figure 7.13

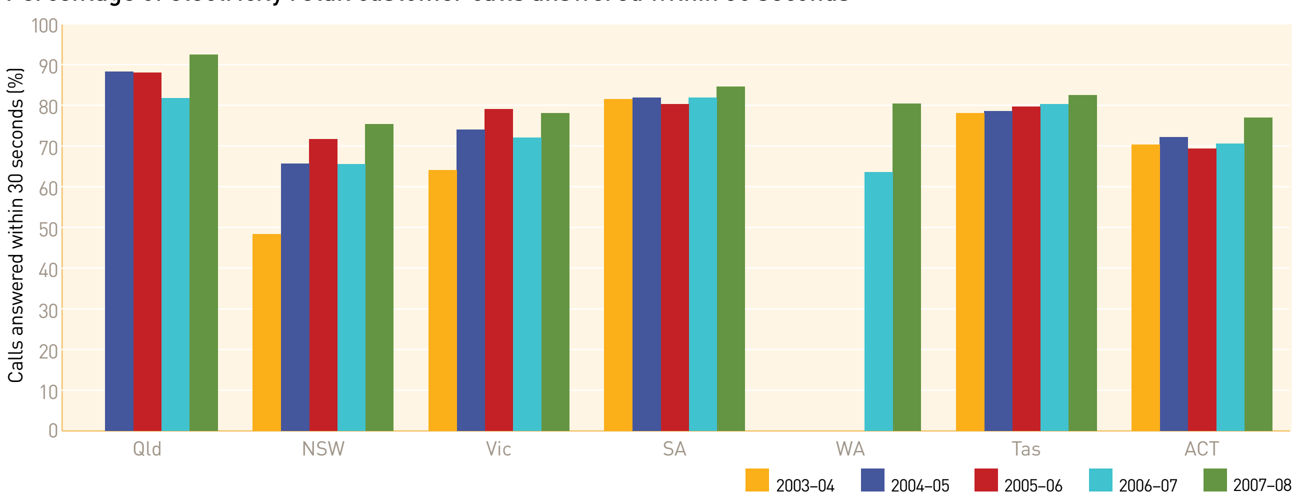
Electricity retail customer complaints, as a percentage of total customers

Note: Queensland data are not available for all years. Western Australia commenced publication of these data in 2006–07.

Source: see figure 7.14.

Figure 7.14

Percentage of electricity retail customer calls answered within 30 seconds



Notes:

South Australian and Victorian data from 2005–06 include both electricity and gas customers. From 2007–08, call response rates in Tasmania are for calls answered within 30 seconds. For previous years, the data were based on a 20 second target.

Queensland data are not available for all years. Western Australia commenced publication of these data in 2006–07.

Sources for figures 7.11–7.14: Reporting against URF templates and performance reports on the retail sector by IPART (New South Wales), the ESC (Victoria), ESCOSA (South Australia), OTTER (Tasmania), the QCA and the Department of Mines and Energy (Queensland), the ICRC (ACT) and the ERA (Western Australia). The 2006–07 and 2007–08 data for the ACT are preliminary data provided by the ICRC.

7.6 Energy efficiency

Energy efficiency measures are products or strategies that use less energy for the same or higher performance, compared with an existing system or product. While such measures can improve the efficiency of energy use, there are wider benefits. They can, for example, ease congestion in network infrastructure, allow the deferral of some capital expenditure, reduce the incidence of wholesale electricity price spikes (and retailers' hedging costs) and improve security of supply. Such measures to improve energy efficiency are being implemented throughout the retail sector (see section 7.6.1).

Demand management measures that address growth in demand (especially peak demand) for electricity are another way to improve efficiency in energy use. These measures often operate via the distribution network sector (see section 6.8).

7.6.1 Jurisdictional energy efficiency initiatives

Many state governments are implementing programs to promote energy efficiency:

- In June 2007 the Queensland Government released its climate change strategy, ClimateSmart 2050. The strategy encourages investment in energy saving technologies to reduce greenhouse gas emissions in Queensland businesses and homes, and increase energy conservation.[49]
  Queensland's Smart Energy Savings Program commenced on 1 July 2009. The program requires medium to large energy customers to complete energy conservation audits and develop action plans to reduce their energy use.[50]
- The New South Wales Energy Savings Scheme provides $150 million over four and a half years on projects to save energy, reduce peak electricity demand, and delay the need for additional energy generation and distribution infrastructure.[51] It also aims to stimulate investment and increase public awareness of the benefits of energy savings.
- The Victorian Energy Efficiency Target Scheme, which commenced on 1 January 2009, sets an overall target for energy savings. The scheme operates in phases, with new scheme targets and prescribed activities set for each three year phase. The first phase (2009–11) sets a target annual reduction of 2.7 million tonnes of greenhouse gas emissions.[52] The scheme requires energy retailers to meet individual targets through energy efficiency activities, such as providing householders with energy saving products and services.
- South Australian retailers have been subject to the Residential Energy Efficiency Scheme from 1 January 2009. Initial targets are set for a three year period ending 2011.[53] The scheme requires retailers to meet targets for improving household energy efficiency (for example, through the use of ceiling insulation, draught proofing and more efficient appliances) and to provide energy audits to low income households.
- The ACT Government released its climate change strategy: *Weathering the change, ACT climate change strategy 2007–2025* in July 2007. This strategy includes the set up of the Home Energy Advice Team funded by the ACT Government to provide free, independent, expert advice on how to improve the energy efficiency of ACT residences.[54] The ACT Government has also committed $40 million to improve the energy efficiency of schools and public housing.

49 Department of Mines and Energy (Queensland), 'Smart Energy Policy', 23 April 2009, viewed May 2009, www.dme.qld.gov.au.

50 Office of Clean Energy (Queensland), 'Smart Energy Savings Fund', 14 May 2009, viewed May 2009, www.cleanenergy.qld.gov.au.

51 Department of Environment and Climate Change (New South Wales), 'NSW Energy Efficiency Strategy', 27 March 2009, viewed May 2009, www.environment.nsw.gov.au.

52 ESC (Victoria), 'Victorian Energy Efficiency Target Scheme', 2 February 2009, viewed May 2009, www.esc.vic.gov.au.

53 ESCOSA (South Australia), 'Residential Energy Efficiency Scheme', 21 April 2009, viewed May 2009, http://dtei.sa.gov.au.

54 Department of the Environment, Climate Change, Energy and Water (ACT), *Weathering the change—climate change strategy action plan one 2007–2011*, Canberra, 2007.

7.7 Future regulatory arrangements

Governments agreed in the Australian Energy Market Agreement 2004 (as amended) that NEM jurisdictions would transfer non-price regulatory functions to a national framework for the AEMC and the AER to administer. These functions include:

- the obligation on retailers to supply small customers
- small customer market contracts and marketing
- retailer business authorisations, ring-fencing and retailer failure
- balancing, settlement, customer transfer and metering arrangements
- enforcement mechanisms and statutory objectives.[55]

Non-price regulatory functions for gas retail in the Northern Territory will also be transferred to the national framework.

As part of the reform plan, work is proceeding on the development of a National Energy Customer Framework to regulate the retail supply of electricity and gas to customers. In April 2009 the MCE Standing Committee of Officials released the first exposure draft of the framework.[56] The proposed framework is comprised of a National Energy Retail Law, National Energy Retail Rules and National Energy Retail Regulations.

The AER's functions under the exposure draft include:

- monitoring the compliance of regulated entities and other persons with the requirements of the national framework, and conducting compliance audits
- overseeing contractual arrangements among retailers, distributors and customers
- preparing and publishing annual compliance reports for the national framework, and making guidelines and procedures to support this role
- preparing and publishing retail performance reports covering matters such as customer service and affordability, as well as retail market activity
- taking enforcement action for breaches of retail laws
- publishing retailer standing offer prices
- granting retailer authorisations and exemptions from the requirement to obtain an authorisation, and establishing a public register with this information
- establishing and maintaining a customer consultative group
- conducting performance audits on hardship, and developing hardship indicators for performance reporting.

Under the current proposals, the states and territories will retain responsibility for price control of default tariffs unless they choose to transfer those arrangements to the AER and the AEMC.

A second exposure draft of the legislative package is scheduled for release in late 2009. The MCE anticipates the legislation changes required to implement the national framework will be introduced in the South Australian parliament in 2010.

55 Australian Energy Market Agreement 2004, as amended.

56 MCE Standing Committee of Officials, *Explanatory material—first exposure draft, National Energy Retail Law, National Energy Retail Regulations, National Energy Retail Rules*, Canberra, April 2009, pp. 1–2, 4–19, 20–1.

PART THREE NATURAL GAS

Matthias Kulka (Corbis)

Natural gas is predominately made up of methane, a colourless and odourless gas. There are two main sources of natural gas in Australia. Conventional natural gas is found in underground reservoirs trapped in rock, often in association with oil. It may occur in onshore or offshore reservoirs. Coal seam gas is produced during the creation of coal from peat. The methane is adsorbed onto the surface of micropores in the coal. There are also renewable sources of methane, including biogas (landfill and sewage gas) and biomass, which includes wood, wood waste and sugarcane residue (bagasse). Renewable sources supply around 16 per cent of Australia's primary gas use.

NATURAL GAS

The natural gas supply chain begins with exploration and development activity, which may involve geological surveys and the drilling of wells. Exploration typically occurs in conjunction with the search for other hydrocarbon deposits, such as oil. At the commercialisation phase, the extracted gas is processed to separate the methane from the liquids and other gases that may be present, and to remove any impurities, such as water and hydrogen sulphide.

The gas extracted from a well may be used on site as a fuel for electricity generation or for other purposes. More commonly, however, gas fields and processing facilities are located some distance from the cities, towns and regional centres where the gas is consumed. High pressure transmission pipelines are used to transport natural gas from the source over long distances. A network of distribution pipelines then delivers gas from points along the transmission pipelines to industrial customers, and from gate stations (or city gates) to consumers in cities, towns and regional communities. Gate stations measure the natural gas leaving a transmission system for billing and gas balancing purposes, and are used to reduce the pressure of the gas before it enters the distribution network.

Retailers act as intermediaries in the supply chain. They enter contracts for wholesale gas, transmission and distribution services, and 'package' the services for sale to industrial, commercial and residential consumers.

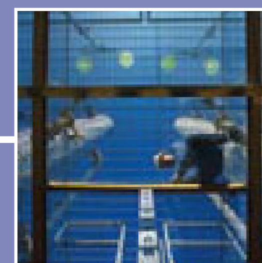
Unlike electricity, natural gas can be stored, usually in depleted gas reservoirs, or it can be converted to a liquefied form for storage in purpose-built facilities. Liquefied natural gas is transported by ship to export markets. It is also possible to transport liquefied natural gas by road or pipeline.

Part three of this report provides a chapter-by-chapter survey of each link in the supply chain. Chapter 8 considers upstream gas markets, including exploration, production and wholesale trade. It discusses the supply of gas for domestic use and the export of liquefied natural gas. Chapters 9 and 10 provide data on the gas transmission and distribution sectors, and chapter 11 considers gas retailing.

Domestic gas supply chain

PRODUCTION

Gas is extracted from wells in explored fields.

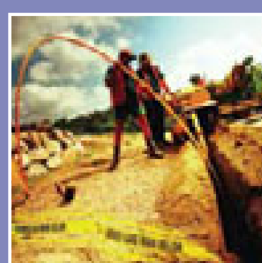


PROCESSING

Extracted gas often requires processing to separate the methane and to remove impurities.

TRANSMISSION

High pressure transmission pipelines are used to transport natural gas over long distances.

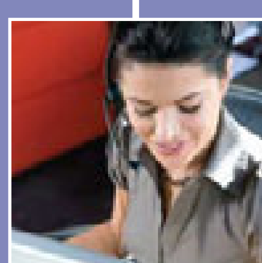


DISTRIBUTION

Distribution networks are used to deliver gas to industrial customers and cities, towns and regional communities.

RETAIL

Retailers act as intermediaries, contracting for gas with producers and pipeline operators to provide a bundled package for on-sale to customers.



CONSUMPTION

Customers use gas for a number of applications, ranging from electricity generation and manufacturing to domestic use such as heating and cooking.

Image sources: Production, Woodside; Processing, Matthias Kulka (Corbis); Transmission, Jemena; Retail, Sadie Dayton (Corbis); Consumption, Vito Elefante (iStockphoto.com).

8 UPSTREAM GAS MARKETS

The upstream gas industry encompasses several phases, including exploration for gas resources, field development, gas gathering and, finally, the processing of natural gas. The wholesale gas market involves sales by producers and storage providers to energy retailers and other major customers. While the market largely remains characterised by confidential long term contracts, recent initiatives have enhanced transparency and competitive conditions.

8 UPSTREAM GAS MARKETS

This chapter considers:

- Australia's natural gas resources
- the exploration and development of gas resources
- gas production and consumption
- upstream industry structure, including participants and ownership changes
- gas wholesale markets
- gas prices
- current market developments, including the Gas Market Bulletin Board and a short term trading market
- reliability of supply.

8.1 Exploration and development

Exploration for natural gas typically occurs in conjunction with the search for other hydrocarbon deposits such as oil and coal. The exploration process is characterised by large sunk costs and a relatively low probability of success. Activity levels are driven by a range of factors, including projected energy prices, the availability of acreage, equipment costs, perceived risks and rewards, and the availability of finance.

The costs incurred during this phase relate to surveying and drilling to identify possible resources, and acquiring exploration permits. In recent years, rising equipment costs have significantly increased the cost of offshore exploration and development. Given the cost and risk characteristics, exploration tends to be undertaken through joint venture arrangements so project partners share costs. If exploration is successful, the parties may proceed to the production phase or sell their interest to other parties.

In the two years to June 2009, petroleum exploration expenditure in Australia was estimated at over $3 billion—the highest on record.[1] The Australian Bureau of Agricultural and Resource Economics (ABARE) linked this growth to projections that global energy prices will continue to rise over the longer term. The rise is accounted for mainly by growth in offshore exploration in Western Australia and exploration activity in Queensland associated with the discovery of coal seam gas (CSG).[2]

Government control the rights to conduct exploration activity—including seismic acquisition and exploratory drilling—and develop gas fields. In Australia, the states and territories control onshore resources and those in coastal waters, while the Australian Government has jurisdiction over resources in offshore waters outside the 3 nautical mile boundary. Governments release acreage each year for exploration and development.

The rights to explore, develop and produce gas and other petroleum products in a specified area or 'tenement' are documented in a lease or licence (also referred to as a 'title' or 'permit'). Licences allocated in Australia include exploration, assessment (retention) and production licences:

- An *exploration* licence provides a right to explore for petroleum, and to carry on such operations as are necessary for that purpose, in the permit area.
- An *assessment* or *retention* licence provides a right to conduct geological, geophysical and geochemical programs to evaluate the development potential of the petroleum believed to be present in the permit area.
- A *production* licence provides a right to explore for and recover petroleum, and carry on such operations as are necessary for those purposes, in the permit area.

Governments usually allocate petroleum tenements through a work program bidding process, which operates like a competitive tendering process. Under this approach, anyone may apply for a right to explore, develop or produce in a tenement based on offers to perform specified work programs. The relevant minister chooses the successful applicant by assessing the merits of the work program, the applicant's financial and technical capacity, the applicant's environmental impact statement, and any other criteria relevant to a tender. While the approach to issuing licences is relatively consistent across states and territories, licence tenure and conditions differ significantly.

8.2 Australia's natural gas resources

Natural gas consists mainly of methane. The two main types of natural gas in Australia are conventional natural gas and CSG. Conventional natural gas is found in underground reservoirs trapped in rock, often in association with oil. But CSG is produced during the creation of coal from peat. In addition, renewable gas sources such as biogas (landfill and sewage gas) and biomass (including wood, wood waste and sugarcane residue) supplied around 3 per cent of Australia's primary energy consumption in 2008–09.[3]

Australia has abundant natural gas reserves (table 8.1). At June 2009 total *proved and probable reserves*—those with reasonable prospects for commercialisation—stood at around 60 000 petajoules (PJ), comprising:

- 39 000 PJ of conventional natural gas
- 21 000 PJ of CSG.[4]

Total proved and probable reserves increased by around 15 per cent in 2008–09. This increase was mainly due to the discovery of further CSG reserves in Queensland and New South Wales. Total proved and probable CSG reserves rose from 12 000 PJ in June 2008 to 21 000 PJ in June 2009.

1 ABARE, *Minerals and energy: major development projects*, April 2009 listing, Canberra, 2009.
2 Australian Bureau of Statistics, *Mineral and petroleum exploration*, ABS cat. no. 8412.0, Canberra, March 2008; ABARE, *Minerals and energy: major development projects*, April 2009 listing, Canberra, 2009.
3 A Schultz, *Energy Update 2009*, ABARE, August 2009, p. 2.
4 EnergyQuest, *Energy Quarterly*, August 2009.

Table 8.1 Natural gas reserves and production in Australia, 2009

GAS BASIN	PRODUCTION (YEAR TO JUNE 2009)		PROVED AND PROBABLE RESERVES[2] (JUNE 2009)	
	PETAJOULES	PERCENTAGE OF DOMESTIC SALES	PETAJOULES	PERCENTAGE OF AUSTRALIAN RESERVES
CONVENTIONAL NATURAL GAS[1]				
WESTERN AUSTRALIA				
Carnarvon	322	32.2	28 739	47.7
Perth	7	0.7	21	0.0
NORTHERN TERRITORY				
Amadeus	19	1.9	181	0.3
Bonaparte	0	0.0	1 638	2.7
EASTERN AUSTRALIA				
Cooper (South Australia – Queensland)	124	12.4	1 084	1.8
Gippsland (Victoria)	230	23.0	5 625	9.3
Otway (Victoria)	116	11.6	1 291	2.1
Bass (Victoria)	18	1.8	287	0.5
Surat–Bowen (Queensland)	16	1.6	212	0.4
Total conventional natural gas	852	85.0	39 079	64.9
COAL SEAM GAS				
Surat–Bowen (Queensland)	143	14.3	19 726	32.7
Sydney (New South Wales)	5	0.5	1 452	2.4
Total coal seam gas	148	14.8	21 178	35.1
AUSTRALIAN TOTALS	**1 000**	**100.0**	**60 257**	**100.0**
LIQUEFIED NATURAL GAS (EXPORTS)				
Carnarvon (Western Australia)	766			
Bonaparte (Northern Territory)	14			
Total liquefied natural gas	780			
TOTAL PRODUCTION	**1 780**			

1. Conventional natural gas reserves include liquefied natural gas and ethane.
2. Proved reserves are those for which geological and engineering analysis suggests at least a 90 per cent probability of commercial recovery. Probable reserves are those for which geological and engineering analysis suggests at least a 50 per cent probability of commercial recovery.

Source: EnergyQuest, *Energy Quarterly*, August 2009.

These estimates of total gas reserves rise sharply if factoring in *contingent resources*, which are known accumulations that are not yet commercially viable.[5] The development of CSG has expanded rapidly in the current decade, and ongoing exploration will likely add to Australia's natural gas reserves.

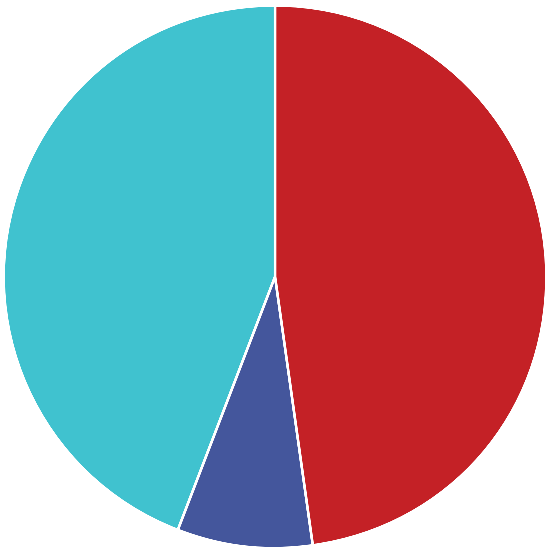
Australia produced 1780 PJ of natural gas in the year to June 2009, of which around 56 per cent was for the domestic market (figure 8.1). The CSG share of total production was only around 8 per cent, but is rising rapidly. Around 44 per cent of Australia's gas production—all currently sourced from offshore basins in Western Australia and the Northern Territory—is exported as liquefied natural gas (LNG).

8.2.1 Geographic distribution

The principal sources of natural gas production are Western Australia's offshore Carnarvon Basin and Victoria's offshore Gippsland Basin (figure 8.2).

5 Official sources in 2007 estimated total reserves, including contingent reserves, at 173 000 PJ (Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, *Final report of the Joint Working Group on Natural Gas Supply*, Canberra, September 2007, p. 7).

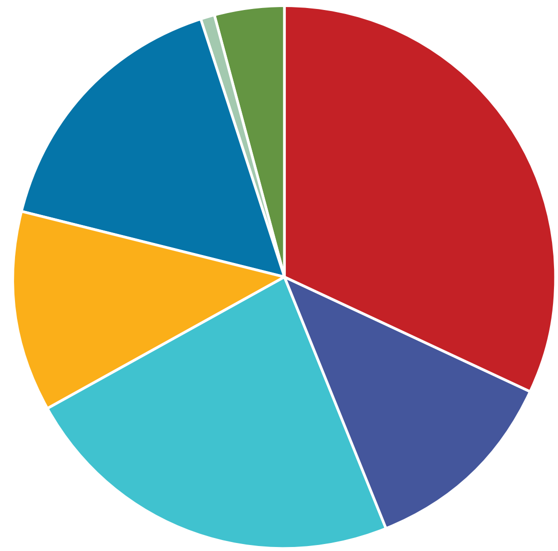
Figure 8.1
Australian natural gas production, 2008–09



CSG, coal seam gas; LNG, liquefied natural gas.

Source: EnergyQuest, *Energy Quarterly*, August 2009.

Figure 8.2
Natural gas production for domestic use, by gas basin, 2008–09



CSG, coal seam gas.

Note: 'Other' consists of the Perth, Amadeus and Bass basins.

Source: EnergyQuest, *Energy Quarterly*, August 2009.

The Cooper Basin (in South Australia and Queensland) has been the principal historical source of gas for New South Wales and South Australia, but its reserves have been steadily declining. In contrast, production in Queensland's Surat–Bowen Basin has risen sharply during the current decade.

Figure 8.3 shows the location of Australia's major natural gas basins, including reserves and production levels, and sets out the contribution of each basin to production for the domestic market. Western Australia's Carnarvon Basin holds about 48 per cent of Australia's natural gas reserves. It supplies around one third of Australia's domestic market and 98 per cent of Australia's LNG exports.[6] The small Perth Basin supplies just under 1 per cent of the domestic market.

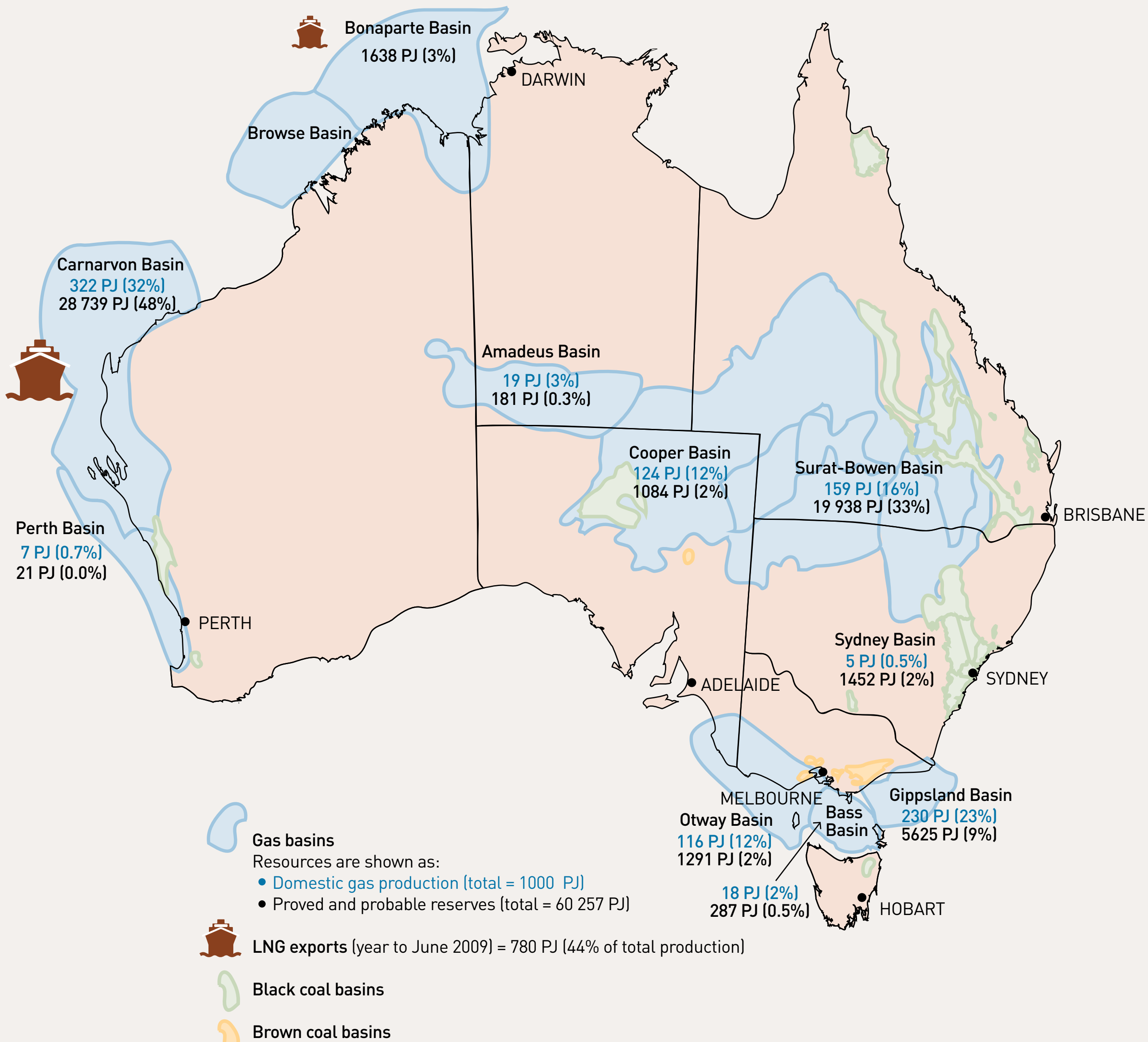
The Bonaparte Basin along the north west coast contains around 3 per cent of Australia's gas reserves. Its development has focused on producing LNG for export, although the Bonaparte Gas Pipeline was recently constructed to ship gas to Darwin for domestic consumption. This capacity will supplement gas from the Amadeus Basin, which is in decline.

Eastern Australia contains around 49 per cent of Australia's natural gas reserves, of which the majority are CSG. This share represents an increase from 40 per cent in 2008, driven by continuing discoveries of CSG in New South Wales and Queensland. The principal sources of natural gas reserves are the Surat–Bowen Basin in Queensland (which meets around 16 per cent of national demand), the Gippsland Basin off coastal Victoria (23 per cent) and the Cooper Basin in central Australia (12 per cent). Production in Victoria's offshore Otway Basin (12 per cent) and Bass Basin (2 per cent) has risen significantly since 2004.[7]

6 The balance of Australia's LNG exports are produced at the Darwin LNG plant and sourced from the Bonaparte Basin. The Darwin plant produces LNG from gas produced in Australia and East Timor.

7 EnergyQuest, *Energy Quarterly*, August 2009.

Figure 8.3
Australia's gas reserves and production, 2009

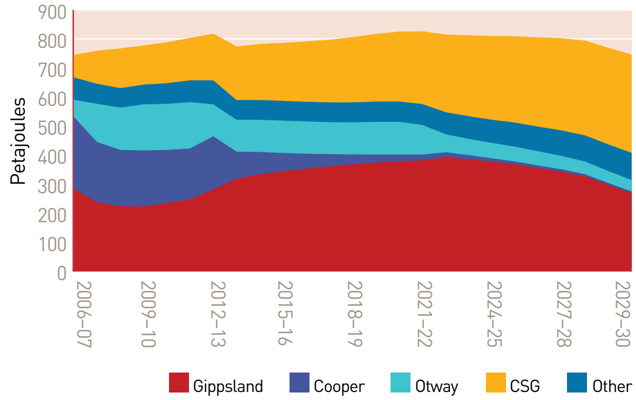


LNG, liquefied natural gas; PJ, petajoules.

Note: Production data for year ended 30 June 2009. Reserves at June 2009.

Data source: EnergyQuest, *Energy Quarterly*, August 2009.

Figure 8.4
Forecast sources of eastern Australia's natural gas production

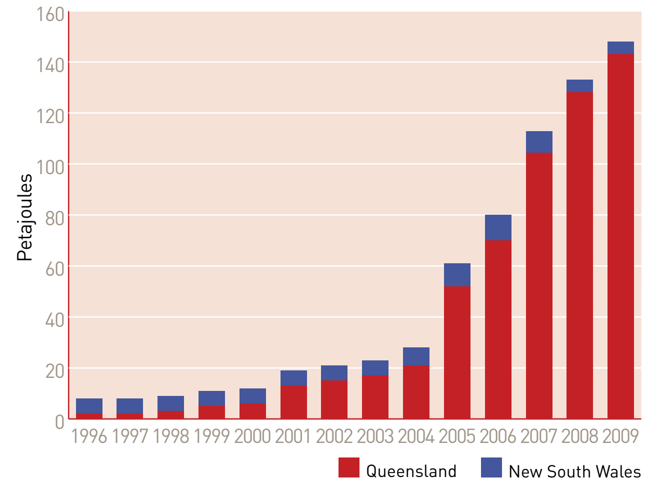


CSG, coal seam gas.

Note: 'Other' consists of conventional natural gas from the Surat–Bowen and Bass basins.

Source: C Cuevas-Cubria and D Riwoe, *Australian energy: national and state projections to 2029–30*, ABARE research report 06.26, prepared for the Australian Government Department of Industry, Tourism and Resources, Canberra, 2006.

Figure 8.5
Coal seam gas production



Note: 2009 data are for the year ended 30 June. Other data are for calendar years.

Source: EnergyQuest.

Changes are forecast in the geography of gas production in eastern and central Australia over the next 25 years (figure 8.4). In particular, the Cooper Basin is a mature gas producing region with diminishing reserves. ABARE has predicted a rapid decline in production rates in the Cooper Basin after about 2011, to be replaced by increased supplies from the Victorian basins and CSG from Queensland.[8]

Production of CSG has risen exponentially since 2004 (figure 8.5), with the bulk of activity occurring in the Surat–Bowen Basin, which extends from Queensland into northern New South Wales. While the basin is an established supplier of conventional natural gas, it also contains most of Australia's proved and probable CSG reserves. There are also significant reserves of CSG in the Sydney Basin, where commercial production began in 1996.

The development of CSG stemmed initially from the Queensland Government's energy and greenhouse gas reduction policies, but recent improvements in extraction technology have spurred sustained rapid growth. Rising domestic and international energy prices have also strengthened the commercial viability of CSG exploration and production.

Queensland CSG has some commercial advantages, including that it is found closer to the surface than is conventional gas. It also tends to have a relatively high concentration of methane and lower levels of impurities, and is closer to some markets. These features also allow for a more incremental investment in production and transport than required to bring a conventional natural gas development on stream.

While CSG is produced only in Queensland and New South Wales, it is the fastest growing gas production sector. It accounted for almost 23 per cent of gas produced in eastern Australia in the year to June 2009,[9] and it meets over 70 per cent of the Queensland market.[10] In 2008–09 Queensland CSG production rose by around 18 per cent to about 143 PJ.[11]

8 A Syed, R Wilson, S Sandu, C Cuevas-Cubria and A Clarke, *Australian energy: national and state projections to 2029–30*, ABARE research report 07.24, prepared for the Australian Government Department of Resources, Energy and Tourism, Canberra, 2007.

9 EnergyQuest, *Energy Quarterly*, August 2009.

10 AER estimate derived from Hon. Geoff Wilson (Minister for Mines and Energy, Queensland), 'Coal seam methane for a cleaner energy future', Media release, 13 September 2007.

11 EnergyQuest, *Energy Quarterly*, August 2009.

Forecasts by ABARE in 2007 suggested CSG production will supply around 32 per cent of the eastern Australian gas market by 2011–12. They also suggested that production will reach around 529 PJ by 2029–30, making it the principal source of gas supply in eastern Australia (figure 8.4).[12]

8.2.2 Regional markets

The geography of Australia's gas basins and transmission networks gives rise to distinct regional markets. Market analysis often distinguishes three regional markets: eastern Australia, Western Australia and the Northern Territory.[13]

An interconnected transmission pipeline network in south east Australia has enabled gas producers in the Cooper, Gippsland, Otway, Bass and Sydney basins to sell gas to customers across South Australia, Victoria, New South Wales, the Australian Capital Territory (ACT) and Tasmania for a number of years. The completion of the new transmission pipeline extension to the South West Queensland Pipeline—the QSN Link—connected Queensland with these southern markets in January 2009. The QSN Link potentially creates an important source of new interbasin competition, because Queensland sourced CSG from the Surat-Bowen Basin can now compete with gas from Moomba and the southern basins.[14]

Western Australia has no pipeline interconnection with other jurisdictions. It is the largest gas producer nationally, and supplies both the domestic market and most of Australia's LNG exports. The state's LNG export capacity exposes the domestic market to international energy market conditions.

Similarly, the Northern Territory has no pipeline interconnection with other jurisdictions. It has a small domestic market that was historically supplied by gas from the Amadeus Basin. Domestic gas demand will, however, be increasingly sourced from the Bonaparte Basin, which has been exporting LNG since 2006. The Bonaparte Pipeline, completed in December 2008, transports natural gas from the Bonaparte Basin to Darwin. The high pressure transmission pipeline was developed to provide certainty of gas supply to the Northern Territory, as reserves in the Amadeus Basin decline.

8.2.3 Gas production in southern and eastern Australia

The Australian Energy Regulator (AER) draws on data and information provided to the National Gas Market Bulletin Board to publish weekly reports on gas market activity in southern and eastern Australia.[15] The reports covers gas flows on registered pipelines, as well as production volumes from gas plants into end markets. Table 8.2 compares average daily gas production in major basins in the third quarter of 2009, compared with the same period in 2008.

While total production for third quarter 2009 was down 6 per cent from the same period last year, volumes for gas plants in the Surat–Bowen Basin increased by 28 per cent, reflecting strong growth in Queensland's CSG sector. In contrast, production from Victorian basins was lower than at the same time last year, including a 16 per cent fall in production at Longford. In part, this decrease correlates with increased gas flows from the northern basins that enter Victoria via the New South Wales – Victoria interconnect.[16]

8.3 Domestic and international demand for Australian gas

Australia consumed around 1000 PJ of natural gas, including conventional natural gas and CSG, in 2008–09. This total was slightly down from 1016 PJ

12 A Syed, R Wilson, S Sandu, C Cuevas-Cubria and A Clarke, *Australian energy: national and state projections to 2029*–30, ABARE research report 07.24, prepared for the Australian Government Department of Resources, Energy and Tourism, Canberra, 2007.

13 See, for example, Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, *Final report of the Joint Working Group on Natural Gas Supply*, Canberra, September 2007, pp. 7–8;

14 For further information on the gas transmission network, see chapter 9 of this report.

15 The AER's weekly gas reports are available at www.aer.gov.au/content/index.phtml/itemId/729309.

16 National Gas Market Bulletin Board website (www.gasbb.com.au).

Table 8.2 Average daily production volumes, by basin

PERIOD	SURAT–BOWEN (QLD)	COOPER (SA/QLD)	OTWAY (VIC)	BASS (VIC)	GIPPSLAND (VIC)	TOTAL
Q3 2009 (TJ)	426	377	343	57	767	1 945
Q3 2008 (TJ)	332	353	387	62	910	2 069
Percentage change	28	–6	–11	–8	–16	–6

Q3, third quarter (1 July to 30 September); TJ, terajoules.

Notes: Data for each basin relate to the following production facilities:

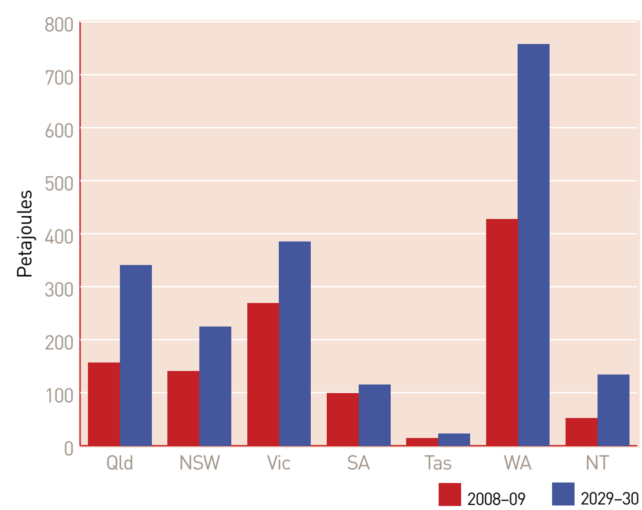
1. Surat–Bowen Basin (Queensland)—Berwyndale South, Fairview, Kenya, Kincora, Kogan North, Peat, Rolleston, Scotia, Spring Gully, Strathblane, Taloona, Wallumbilla and Yellowbank gas plants
2. Cooper Basin (South Australia / Queensland)—Moomba and Ballera gas plants
3. Otway Basin (Victoria)—Iona Underground Gas Storage, and Minerva and Otway gas plants
4. Bass Basin (Victoria)—Lang Lang gas plant
5. Gippsland Basin (Victoria)—Longford gas plant.

Source: Gas Market Bulletin Board website (www.gasbb.com.au).

consumed in 2007–08.[17] Natural gas has a range of industrial, commercial and domestic applications within Australia. It is an input to manufacturing pulp and paper, metals, chemicals, stone, clay, glass and certain processed foods. In particular, natural gas is a major feedstock in ammonia production for use in fertilisers and explosives. It is increasingly used for electricity generation, mainly to fuel intermediate and peaking generators. It is also used in the mining industry, to treat waste materials and for incineration, drying, dehumidification, heating and cooling. In the transport sector, natural gas in a compressed or liquefied form is used to power vehicles. The residential sector uses natural gas mainly for heating and cooking.

Figure 8.6 sets out ABARE forecast data on primary consumption of natural gas by state and territory in 2008–09 and 2029–30. Western Australia and Victoria have the highest consumption levels, while demand growth is forecast to be strongest over the next 20 years in Queensland, Western Australia and the Northern Territory.

Figure 8.6
Forecast primary gas consumption

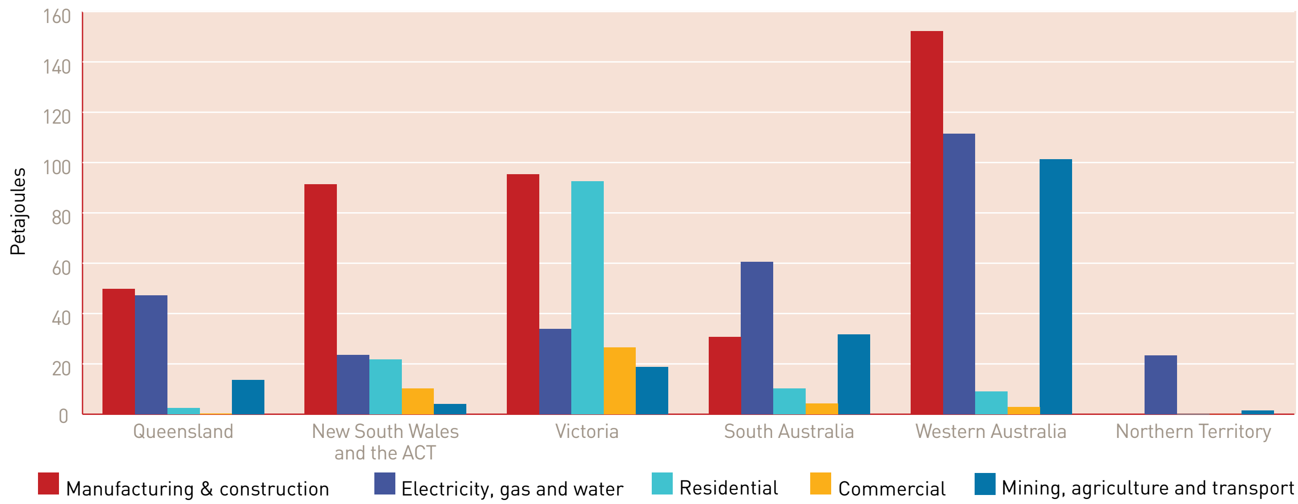


Source: A Syed, R Wilson, S Sandu, C Cuevas-Cubria and A Clarke, *Australian energy: national and state projections to 2029–30*, ABARE research report 07.24, prepared for the Australian Government Department of Resources, Energy and Tourism, Canberra, 2007.

The consumption profile varies across the jurisdictions (figure 8.7). Natural gas is widely used in most jurisdictions for industrial manufacturing. Western Australia, South Australia, Queensland and the Northern Territory are especially reliant on natural gas for electricity generation. In Western Australia, the mining sector is also a major user of gas, mainly for power generation. Household demand is relatively small, except in Victoria where residential demand accounts for around one third of total consumption. This reflects the widespread use of natural gas for cooking and heating in that state.

17 EnergyQuest, *Energy Quarterly*, August 2009.

Figure 8.7
Primary natural gas consumption, by industry



Note: Data for year ended 30 June 2005.

Source: ABARE

8.3.1 Liquefied natural gas exports

The production of LNG converts natural gas into liquid. The development of an LNG export facility requires large upfront capital investment in processing plant and port and shipping facilities. The magnitude of investment means a commercially viable LNG project requires access to substantial reserves of natural gas. The reserves may be sourced through the LNG owner's interests in a gas field, a joint venture arrangement with a natural gas producer, or long term gas supply contracts.[18]

Australia has LNG export projects in the North West Shelf (annual capacity of around 16.3 million tonnes) and Darwin (annual capacity of 3.5 million tonnes).[19] Recent LNG developments include the $50 billion Gorgon project in Western Australia (operated by Chevron with a 50 per cent share, with Shell and ExxonMobil (Esso) each holding 25 per cent). The project is scheduled to begin operation in 2014 and is expected to produce around 15 million tonnes of LNG per year—equal to Australia's current total LNG production.

The Pluto LNG project, also in Western Australia, is set to become Australia's fastest developed LNG project—from discovery of the gas field in 2005, to commencement of gas production in late 2010. The Pluto project is set to become Australia's third LNG project and has a forecast capacity of 4.3 million tonnes of LNG per year.[20]

Australia is the world's sixth largest LNG exporter after Qatar, Malaysia, Indonesia, Algeria and Nigeria. In 2008–09 Australia exported around 780 PJ of LNG, mostly from the Carnarvon Basin.[21] LNG shipments from Darwin began in February 2006. At present, LNG accounts for around 44 per cent of Australia's natural gas production. ABARE projects this ratio will rise to around 68 per cent by 2029–30.[22]

18 NERA, *The gas supply chain in eastern Australia*, Report to the AEMC, Sydney, March 2008, p. 16.

19 EnergyQuest, *Energy Quarterly*, August 2009.

20 For more information on current LNG developments, see EnergyQuest, 'Australia's natural gas markets: connecting with the world', essay in AER, *State of the energy market 2009*, Melbourne, 2009.

21 EnergyQuest, *Energy Quarterly*, August 2009.

22 A Syed, R Wilson, A Sandu, C Cuevas-Cubria and A Clarke, *Australian energy: national and state projections to 2029–30*, ABARE research report 07.24, prepared for the Australian Government Department of Resources, Energy and Tourism, Canberra, 2007, p. 44.

Rising international LNG prices, together with rapidly expanding reserves of CSG, have improved the economics of developing LNG export facilities in eastern Australia. Several LNG proposals reliant on CSG have been announced for construction in Queensland since early 2007. The proposed projects, which range in size from 1.5 to 14 million tonnes of LNG per year, are being developed by major domestic and international players. All are scheduled to commence production between 2012 and 2015. Table E.1 in the essay in this report sets out details.

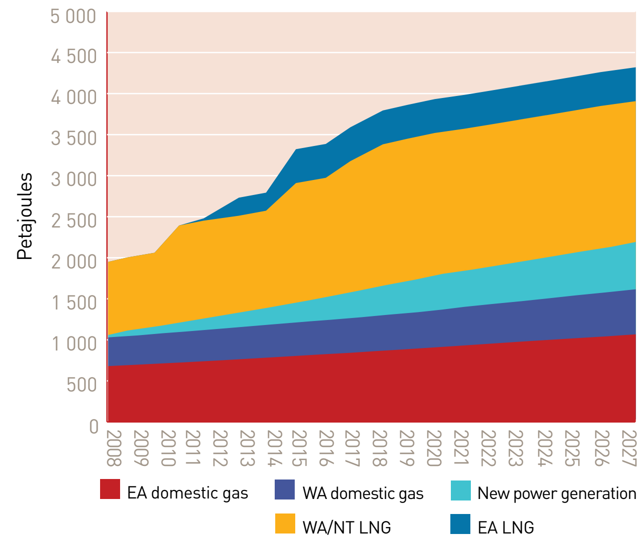
8.3.2 Links between international and domestic gas markets

Figure 8.8 illustrates ACIL Tasman forecasts (published in 2008) of demand for Australia's natural gas over the next 20 years. The forecasts account for the projected effects of the Carbon Pollution Reduction Scheme. ACIL Tasman forecast that demand growth would be driven principally by rising LNG production—in western, northern and eastern Australia—and the increasing use of gas for electricity generation. According to this view, total gas demand would more than double to around 4300 PJ (including exports) over the next 20 years.[23]

Given projected growth in LNG exports from Western Australia, the Northern Territory and potentially eastern Australia, the adequacy of domestic sources to satisfy Australia's natural gas demand over time has been debated. Assessments of the relationship between international and domestic gas markets typically distinguish among Western Australia, the Northern Territory and eastern Australia.

The Western Australian gas market experienced considerable tightening after 2006, with rising production costs and strong domestic demand occurring at a time when most producers had fully contracted their developed reserves. In addition, rising international energy prices, combined with Western Australia's substantial LNG export capacity,

Figure 8.8
Australian gas demand outlook, 2008–27



EA, eastern Australia; LNG, liquefied natural gas.

Note: Forecasts account for the projected effects of the Carbon Pollution Reduction Scheme and LNG expansion.

Source: ACIL Tasman, 'Australia's natural gas markets: the emergence of competition?', essay in AER, *State of the energy market 2008*, Melbourne, 2008.

put pressure on domestic prices and supply. In June 2008 an explosion at the Varanus Island gas facility put further pressure on the domestic market, reducing domestic gas supplies by 30 per cent for over two months.

International energy prices eased in 2008-09 due to the effects of the global financial crisis on the manufacturing and industrial sectors. This easing was mirrored by softening price pressure in the domestic market (section 8.6.1). Western Australia has been projected, however, to continue to face difficulties in achieving a supply–demand balance until at least 2010.[24] EnergyQuest's essay further analyses the Western Australian market (section E.1.3).

There have been some suggestions that the opening of an LNG export facility in Darwin in 2006 could affect the availability of gas supplies in the Northern Territory. While supply contracts in the Territory

23 ACIL Tasman, 'Australia's natural gas markets: the emergence of competition?', essay in AER, *State of the energy market 2008*, Melbourne, 2008.
24 Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, *Final report of the Joint Working Group on Natural Gas Supply*, Canberra, September 2007, p. 10.

appear to cover the needs of existing customers for up to 15 years, competition to supply LNG exports could pose risks to the market in sourcing additional gas supplies to support major new industrial projects.[25] EnergyQuest estimates that the Blacktip field, which supplies the Darwin LNG plant, could meet current Northern Territory needs for about 70 years. The Bonaparte Pipeline, commissioned in 2008, supplies gas from Blacktip to the domestic market.

In eastern Australia, an interaction of several factors will affect the supply–demand balance over the next few years. Since the 1990s improved pipeline interconnection among the eastern gas basins has enhanced the flexibility of the market to respond to customer demand. Importantly, the completion in 2008 of the QSN Link pipeline from Queensland to southern Australia resulted in an interconnected pipeline network linking Queensland, New South Wales, the ACT, Victoria, South Australia and Tasmania (see chapter 9).

While new pipeline investment and rising CSG reserves are strengthening the supply base, a number of factors may also put upward pressure on demand. Eastern Australia is insulated from global gas markets, but this will change with the likely development of LNG export projects in Queensland. The proposed introduction of the Carbon Pollution Reduction Scheme will also likely increase reliance on natural gas as a fuel for electricity generation.

ACIL Tasman projected that a 4 million tonne per year LNG plant (as proposed by Santos) could divert significant quantities of gas to exports. It argued that such diversion, while maybe not leaving the domestic market short of supply, would likely require earlier reliance on higher cost and less productive sources of CSG than if the LNG projects did not proceed. This would have implications for domestic gas prices.[26]

The EnergyQuest essay in this report argues that domestic gas supplies may increase (and price pressure may ease) in the medium term during the ramp-up phase of Queensland's CSG–LNG projects. In the longer term, prices for new domestic gas contracts may rise closer to international levels, as has occurred in Western Australia.

Features of east coast markets may cushion price impacts. Unlike Western Australia, the east coast has a number of gas basins, with greater diversity of supply. There is substantial exploration acreage with relatively low barriers to entry, and an extensive gas transmission network linking the producing basins.

8.4 Industry structure

The prevalence of high sunk costs and the relatively small number of Australian gas fields mean the supply of natural gas is concentrated in the hands of a small number of producers. It is common for oil and gas companies to establish joint ventures to help manage risk. Typically, the operator holds a substantial interest in the project—for example, the Cooper Basin partnership comprises Santos (the operator and majority owner), along with Beach Petroleum and Origin Energy.

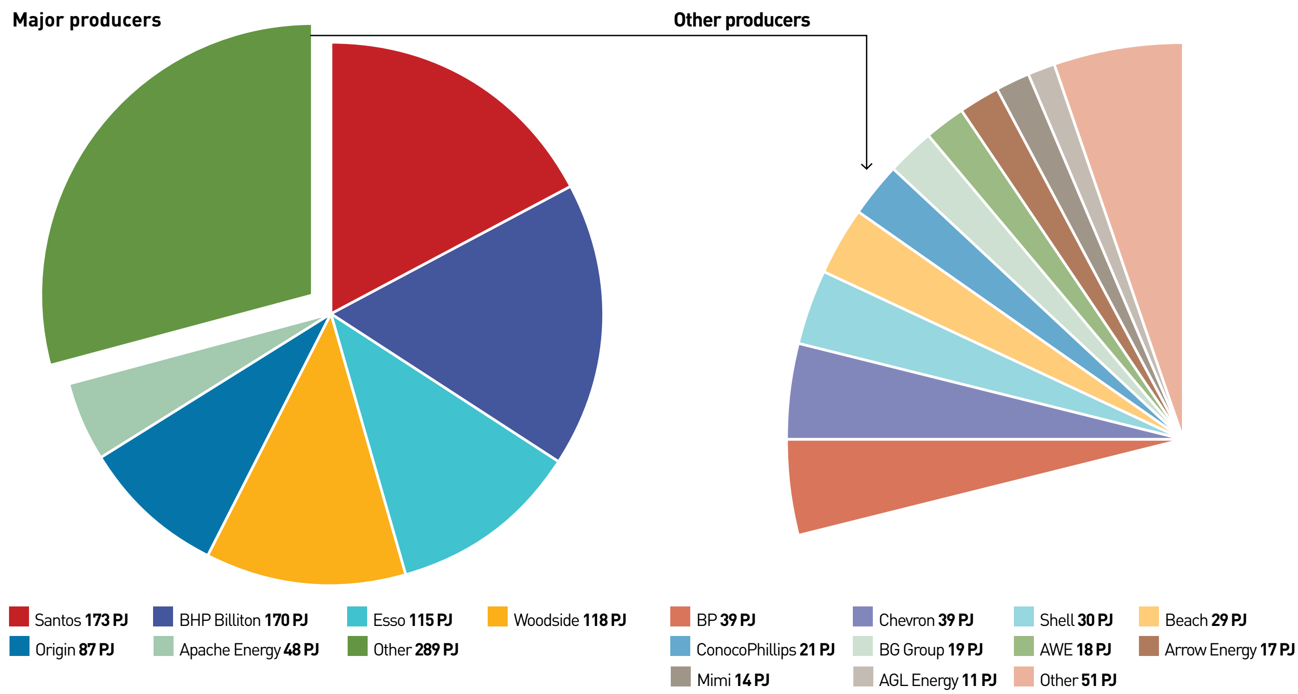
The structures of the exploration and development sector and the gas production sector differ somewhat, although many participants—especially the large corporations—are active in both. The three main types of entity involved in gas and oil exploration are:

> international majors—multinational corporations with large production interests and substantial exploration budgets (for example, BP, BHP Billiton, Esso, Chevron and Apache Energy)
> Australian majors—major Australian energy companies with significant production interests and exploration budgets (for example, Woodside Petroleum, Santos and Origin Energy)
> juniors—smaller exploration and production companies, which may or may not engage in gas production (for example, Australian Worldwide Exploration and Arrow Energy).

25 Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, *Final report of the Joint Working Group on Natural Gas Supply*, Canberra, September 2007, p. 11.

26 ACIL Tasman, 'Australia's natural gas markets: the emergence of competition?', essay in AER, *State of the energy market 2008*, Melbourne, 2008.

Figure 8.9
Natural gas producers supplying the domestic market, 2008–09



PJ, petajoules.

Note: Some corporate names have been shortened or abbreviated.

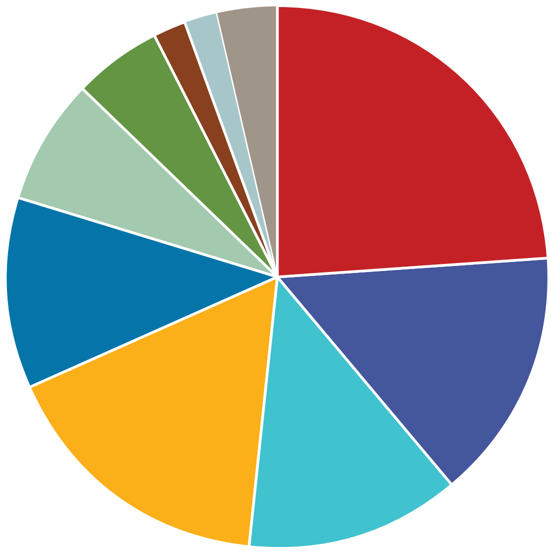
Source: EnergyQuest, *Energy Quarterly*, August 2009.

International majors tend to be involved in the larger offshore oil and LNG projects. Australian majors and smaller companies focus on mainly onshore discoveries, typically for natural gas sales to the domestic market. A number of Australian majors—for example, Woodside Petroleum, Origin Energy, Santos and Arrow Energy—are LNG exporters or are developing LNG projects. Junior explorers often play a significant role in higher risk greenfields exploration, such as the early phase of CSG developments.

Gas production in Australia is relatively concentrated. While over 100 companies are involved in gas and oil exploration, only around 35 produce gas. The six majors supplied around 71 per cent of the domestic market in 2008–09, down from 77 per cent in 2007–08. Santos and BHP Billiton each supplied around 17 per cent, followed by Esso (12 per cent), Woodside (12 per cent), Origin Energy (9 per cent) and Apache Energy (5 per cent). The next tier of players in terms of market share include BP, Chevron, Beach Petroleum, Shell and BG Group (figure 8.9).

The rise of CSG has involved the entry of several new players in both the exploration and production sectors over the past decade. New entrants have included Queensland Gas Company, Sydney Gas, Sunshine Gas and coal and oil producers Anglo Coal and Mosaic Oil (figure 8.10). Since 2007 several international majors, including BG Group, ConocoPhillips and Petronas, have entered the market as project partners with domestic players, with a view to developing CSG resources for LNG export (see section 8.4.3 and section E.2.2 in the essay in this report).

Figure 8.10
Coal seam gas producers in Australia, 2008–09



PJ, petajoules.

Note: Some corporate names have been shortened or abbreviated.

Source: EnergyQuest, *Energy Quarterly*, August 2009.

8.4.1 Vertical integration

The increasing use of natural gas as a fuel for electricity generation creates synergies for energy retailers to manage price and supply risk through equity in gas production and gas fired electricity generation. The energy retailers Origin Energy and AGL Energy each have substantial interests in gas production and electricity generation:

- Origin Energy is a leading energy retailer in Queensland, Victoria and South Australia; is a significant gas producer; and is expanding its electricity generation portfolio. It has held a minority interest in gas production in the Cooper Basin for some time, and since 2000 has expanded its equity in CSG production in Queensland and in conventional gas production in Victoria's Otway and Bass basins.
  It has also been developing new gas fired electricity generation capacity in Queensland, Victoria, South Australia and New South Wales. This includes the Uranquinty power station in New South Wales (commissioned in January 2009), the Darling Downs power station in Queensland (planned for commissioning in late 2009) and the Mortlake power station in Victoria (set for completion in 2010). Origin Energy also completed an expansion of the Quarantine power station in South Australia in March 2009.
- AGL Energy is a leading energy retailer in Queensland, Victoria, New South Wales and South Australia; is a major electricity generator in eastern Australia; and is increasing its interests in gas production. A relative newcomer to gas production, AGL Energy began acquiring CSG interests in Queensland and New South Wales in 2005. It has continued to expand its portfolio through mergers and acquisitions (see section 8.4.3).

8.4.2 Market concentration

Market concentration within particular gas basins depends on a variety of factors, including the number of fields developed, the ownership structure of the fields, and acreage management and permit allocation. Table 8.3 and figure 8.11 set out EnergyQuest estimates of market shares in gas production for the domestic market in each major basin. Table 8.4 sets out market shares in proved and probable gas reserves (including reserves available for export) at May 2009.

Several major companies have equity in Western Australia's Carnarvon Basin, which is Australia's largest producing basin. Woodside is the largest producer for the domestic market (around 29 per cent), but Apache Energy (14 per cent), Chevron (12 per cent), BP (12 per cent), Santos (9 per cent), BHP Billiton (9 per cent) and Shell (8 per cent) each have significant market share. Ownership of gas reserves is split between these and other entities such as MIMI (owned by Mitsubishi and Mitsui) and the China National Offshore Oil Company (CNOOC). The businesses participate in joint ventures, typically with overlapping ownership interests.

Table 8.3 Market shares in domestic gas production, by basin, calendar year 2008 (per cent)

COMPANY	CARNARVON (WA)	PERTH (WA)	AMADEUS (NT)	COOPER (SA/QLD)	SURAT–BOWEN (QLD)	SYDNEY (NSW)	GIPPSLAND (VIC)	OTWAY (VIC)	BASS (VIC)	ALL BASINS (%)
AGL Energy					5.1	50.0				1.0
Anglo Coal					0.6					0.1
Apache Energy	14.4									4.5
ARC Energy		33.8							8.5	0.4
Arrow Energy					12.0					1.8
AWE		17.5						7.8	33.9	1.5
Beach				21.2	2.2					3.1
Benaris								5.0		0.5
BG Group					15.7					2.3
BHP Billiton	8.5						49.8	26.3		17.9
BP	12.4									3.9
CalEnergy								1.5	15.2	0.4
Chevron	12.4									3.9
ConocoPhillips					3.0					0.4
CS Energy					1.1					0.2
Esso	0.2						49.8			12.5
Inpex	0.1									0.0
Kufpec	1.1									0.3
Magellan			37.8							0.7
MIMI	4.1									1.3
Mitsui					0.5			7.7		0.9
Molopo					0.1					0.0
Mosaic					1.3					0.2
Origin Energy		48.8		14.6	34.2			13.1	42.4	9.5
Petronas					1.8					0.3
Santos	8.6		62.2	64.1	22.0		0.4	18.3		17.6
Shell	8.2									2.6
Sydney Gas						50.0				0.3
Tap	0.7									0.2
Woodside	29.3							20.5		11.5
Other					0.3					0.0
TOTAL (PETAJOULES)	**318**	**8**	**20**	**130**	**149**	**5**	**251**	**110**	**17**	**1008**

Notes:

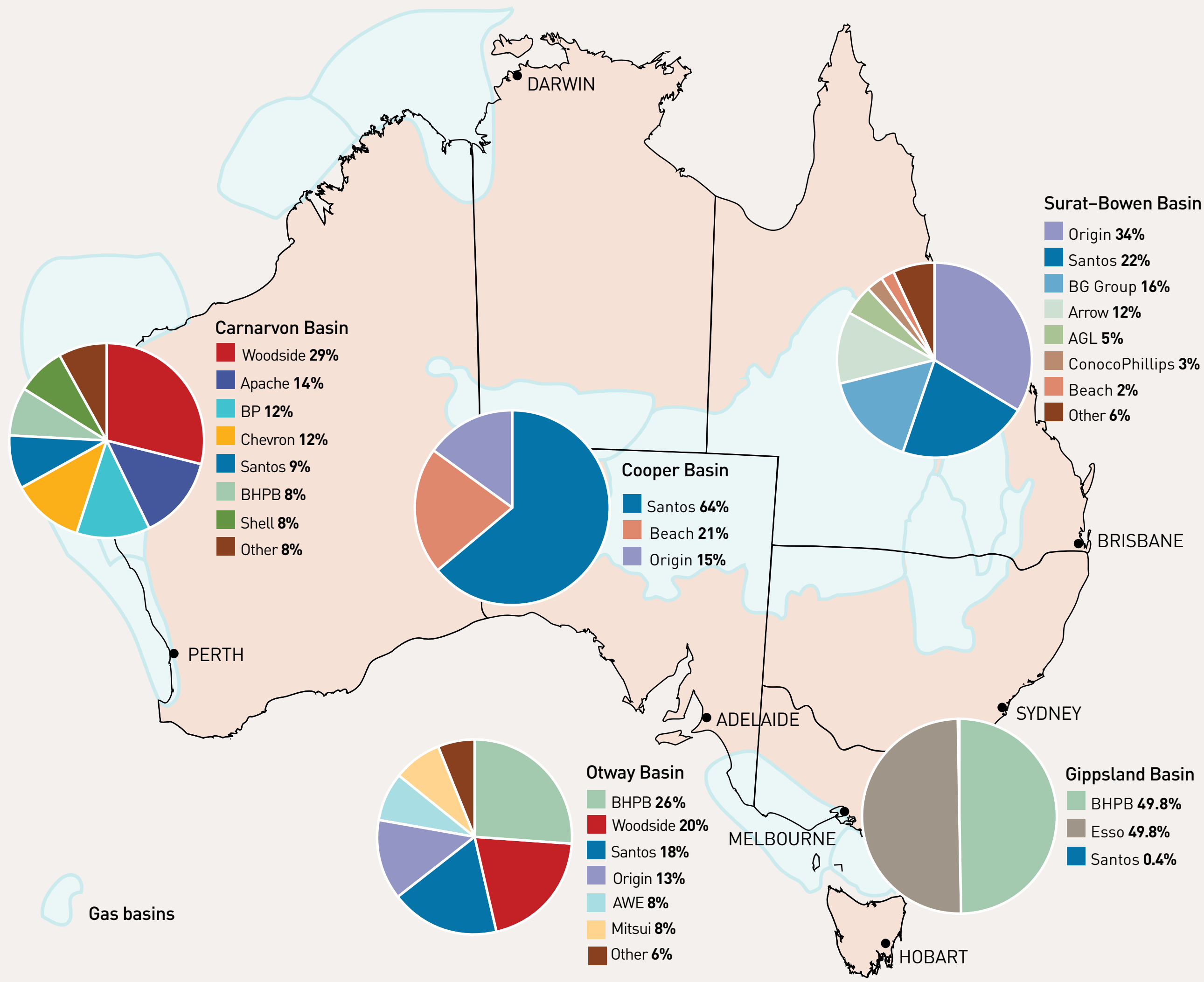
Excludes liquefied natural gas.

Some corporate names have been shortened or abbreviated.

Source: EnergyQuest 2009 (unpublished data).

Figure 8.11

Market shares in domestic gas production, by basin, 2008



AWE, Australian Worldwide Exploration; BHPB, BHP Billiton

Notes:

Excludes liquefied natural gas.

Some corporate names have been shortened or abbreviated.

Source: EnergyQuest 2009 (unpublished data).

Gas for the Northern Territory was historically sourced from the Amadeus Basin and produced by Santos and Magellan. The principal reserves in the Northern Territory are located in the Bonaparte Basin in the Timor Sea. The Italian energy firm Eni owns the majority of Australian reserves in the basin.

While around 22 entities have equity in natural gas fields in eastern Australia, control of the more substantial fields in the Gippsland and Cooper basins is concentrated among a handful of established producers. A joint venture led by Santos (64 per cent) dominates production in South Australia's Cooper Basin. The other participants are Beach Petroleum (21 per cent) and Origin Energy (15 per cent). The same companies participate with slightly different shares on the Queensland side of the basin. New entry by smaller explorers has also occurred in the Cooper Basin in recent years.

The Gippsland, Otway and Bass basins off coastal Victoria serve the Victorian market and export gas to New South Wales, South Australia and Tasmania. A joint venture between Esso and BHP Billiton accounts for around 98 per cent of production in the Gippsland Basin, which is the largest producing basin in eastern Australia. The Otway Basin off south west Victoria has a more diverse ownership base, with BHP Billiton (26 per cent), Woodside (20 per cent), Santos (18 per cent) and Origin Energy (13 per cent) accounting for the bulk of production. The principal producers in the smaller Bass Basin are Origin Energy and Australian Worldwide Exploration, with a combined share of 76 per cent of production. The businesses market gas from the Bass Basin through a joint venture.

The growth of the CSG industry has led to considerable new entry in Queensland's Surat–Bowen Basin over the past decade, and a diverse ownership profile. A number of smaller businesses such as Queensland Gas Company (now owned by BG Group) and Arrow Energy have developed considerable market share, alongside more established entities such as Origin Energy and Santos. Overall, the largest producers in the basin are Origin Energy (34 per cent), Santos (22 per cent), BG Group (16 per cent), Arrow Energy (12 per cent) and AGL Energy (5 per cent). These businesses also own the majority of gas reserves in the Surat–Bowen Basin. Recently, international majors ConocoPhillips, Petronas and Shell acquired 17 per cent, 8 per cent and 3 per cent of gas reserves in the basin respectively.

8.4.3 Mergers and acquisitions

There has been significant merger and acquisition activity in the gas production sector in recent years, with interest since 2006 focused mainly on CSG (and associated LNG proposals) in Queensland and New South Wales. Table 8.5 lists a number of proposed and successful acquisitions from June 2006 to September 2009.

Queensland Gas Company, a significant producer in the Surat–Bowen Basin, has been a focus of acquisition interest. Following an unsuccessful takeover attempt by Santos in 2006, the company sold a 27.5 per cent stake in its assets to AGL Energy in 2007. In 2008 Queensland Gas Company sold a further 20 per cent stake to BG Group. The agreement was based around the development of CSG resources for LNG exports. BG Group acquired full ownership of Queensland Gas Company in March 2009.

BG Group sought to expand its market profile in 2008 by attempting to acquire Origin Energy. The offer was rejected in June 2008, and in September 2008, Origin Energy announced a LNG joint venture with ConocoPhillips.

Table 8.4 Market shares in proved and probable gas reserves, by basin, May 2009 (per cent)

COMPANY	CARNARVON (WA)	BONAPARTE (WA/NT)	PERTH (WA)	AMADEUS (NT)	COOPER (SA/QLD)	SURAT–BOWEN (QLD)	GUNNEDAH (NSW)	CLARENCE MORTON (QLD/NSW)	GLOUCESTER (NSW)	SYDNEY (NSW)	GIPPSLAND (VIC)	OTWAY (VIC)	BASS (VIC)	ALL BASINS (%)
Adelaide Energy												3.2		0.1
AGL Energy						2.9			100.0	100.0				1.3
AJ Lucas						0.3								0.1
Anglo						0.6								0.2
Apache Energy	4.6													2.3
Arrow Energy						10.0								2.9
AWE			53.8									8.2	42.5	0.5
Beach					20.7						1.3			0.5
Benaris												6.3		0.2
BG Group						26.4								7.8
BHP Billiton	11.9										42.7	13.1		10.6
BP	12.1													6.1
CalEnergy												2.5	15.0	0.1
Chevron	12.1													6.1
CNOOC	3.3													1.7
ConocoPhillips		9.4				16.5								5.1
CS Energy								11.4						0.1
Drillsearch					0.4									0.0
Eastern Star Gas							64.9							0.4
Eni		85.4												2.5
Esso											42.7			4.2
Gastar							35.1							0.2
Inpex		1.8												0.1
ITOCHU											0.9			0.1
Kansai Electric	0.8													0.4
Kufpec	0.1													0.1
Magellan				44.7										0.1
Metgasco								88.6						0.5
MIMI	11.8													6.0
Mitsui						0.6						8.2		0.4
Molopo						0.3								0.1
Mosaic						0.3								0.1
Nexus											6.2			0.6
Origin Energy			46.2		12.9	16.7						15.2	42.5	5.8
Petronas						7.7								2.3

COMPANY	CARNARVON (WA)	BONAPARTE (WA/NT)	PERTH (WA)	AMADEUS (NT)	COOPER (SA/QLD)	SURAT-BOWEN (QLD)	GUNNEDAH (NSW)	CLARENCE MORTON (QLD/NSW)	GLOUCESTER (NSW)	SYDNEY (NSW)	GIPPSLAND (VIC)	OTWAY (VIC)	BASS (VIC)	ALL BASINS (%)
Roc											1.8			0.2
Santos	2.7	1.9		55.3	65.9	14.5					4.0	17.9		8.1
Shell	11.9					3.0								6.9
Sojitz											0.5			0.0
Tap	0.1													0.0
Tokyo Gas	0.8													0.4
Tokyo Electric		1.5												0.0
Woodside	27.7											25.4		14.6
Other CSG						0.3								0.1
TOTAL (PETAJOULES)	**28 749**	**1647**	**26**	**190**	**1138**	**16 773**	**336**	**298**	**175**	**82**	**5637**	**1416**	**306**	**56 773**

Notes:

Based on 2P (proved and probable) reserves at May 2009.

Some corporate names have been shortened or abbreviated. Not all minority owners are listed.

Source: EnergyQuest 2009 (unpublished data).

Further acquisitions in 2008 and 2009 based around the development of CSG and CSG-LNG export projects included the following:

> In June 2008 Arrow Energy agreed to sell 30 per cent of its CSG resources in Queensland to Shell.
> In August 2008 ARC Energy merged with Australian Worldwide Exploration.
> In October 2008 Queensland Gas Company acquired all issued shares in Sunshine Gas.
> In December 2008 AGL Energy acquired Sydney Gas Limited and CSG assets from AJ Lucas Group and Molopo Australia in the Gloucester basin in New South Wales.
> In April 2009 Origin Energy acquired an exploration permit in the Surat-Bowen Basin from Pangaea.
> In July 2009 Santos acquired Gastar Exploration's 35 per cent interest in CSG exploration permits and production areas in the Gunnedah Basin in New South Wales. Santos also acquired a 19.99 per cent interest in Eastern Star Gas, a gas explorer in the Gunnedah Basin.

8.5 Gas wholesale markets

Wholesale gas markets involve the sale of gas by producers, mainly to energy retailers, which on-sell it to business and residential customers. In addition, some major industrial, mining and power generation customers buy gas directly from producers in the wholesale market.

8.5.1 Wholesale market contracts

In Australia, wholesale gas is mostly sold under confidential, long term contracts. The trend in recent years has been towards shorter term supply, but most contracts still run for at least five years. Foundation contracts underpinning new production projects are still often struck for terms of up to 20 years. Such long term contracts are commonly argued as being essential to the financing of new projects because they provide reasonable security of gas supply, as well as a degree of cost and revenue stability.

Table 8.5 Upstream gas merger and acquisition activity, June 2006 – September 2009

DATE	PROPOSED MERGER/ACQUISITION	GAS BASINS	STATUS AT SEPTEMBER 2009
June 2006	Arrow Energy acquisition of CH4	Surat–Bowen (Qld)	Completed July 2006
Sept 2006	Beach Petroleum acquisition of Delhi Petroleum	Cooper (Qld/SA)	Completed September 2006
Oct 2006	Santos acquisition of Queensland Gas Company	Surat–Bowen (Qld)	Proposal withdrawn
Jan 2007	AGL Energy and Origin Energy merger	Various	Proposal withdrawn
Jan 2007	AGL Energy acquisition of a 27.5 per cent stake in Queensland Gas Company	Surat–Bowen (Qld)	Completed December 2006
Nov 2007	AGL Energy – Arrow Energy joint venture acquisition of Enertrade's Moranbah gas assets	Surat–Bowen (Qld)	Completed December 2007
April 2008	BG Group acquisition of about 20 per cent of Queensland Gas Company	Surat–Bowen (Qld)	Completed April 2008
May 2008	BG Group acquisition of Origin Energy	Various	Proposal withdrawn September 2008
May 2008	Petronas acquisition of 40 per cent of Santos's LNG project at Gladstone (joint venture)	Surat–Bowen (Qld)	Sales agreement signed June 2009 Final investment decision due first half of 2010
June 2008	Shell acquisition of 30 per cent of Arrow Energy's CSG resources	Surat–Bowen (Qld)	Completed February 2009
Aug 2008	Queensland Gas Company acquisition of Sunshine Gas	Surat–Bowen (Qld)	Completed October 2008
Aug 2008	ARC Energy and Australian Worldwide Exploration merger	Perth (WA) and Bass (Vic)	Completed September 2008
Sept 2008	ConocoPhillips acquisition of 50 per cent of the issued share capital of Origin Energy CSG Ltd	Surat–Bowen (Qld)	Completed October 2008
Oct 2008	BG Group acquisition of remaining shares in Queensland Gas Company	Surat–Bowen (Qld)	Completed March 2009
Dec 2008	AGL Energy acquisition of Sydney Gas Limited	Sydney (NSW)	Completed April 2009
Dec 2008	AGL Energy acquisition of certain CSG assets from AJ Lucas Group Ltd and Molopo Australia Ltd	Gloucester (NSW)	Completed December 2008
April 2009	Origin Energy acquisition of exploration permit ATP 788P from Pangaea Group	Surat–Bowen (Qld)	Completed August 2009
July 2009	Santos acquisition of Gastar Exploration's 35 per cent interest in CSG exploration permits and production areas	Gunnedah CSG (NSW)	Completed July 2009
July 2009	Santos acquisition of Hillgrove Resources's 19.99 per cent interest in Eastern Star Gas	Gunnedah CSG (NSW)	Completed July 2009

Wholesale gas contracts typically include *take or pay* clauses that require the purchaser to pay for a minimum quantity of gas each year regardless of the actual quantity used. Prices may be reviewed periodically during the life of the contract. Between reviews, prices are typically indexed (often to the consumer price index). Contract prices, therefore, do not tend to fluctuate on a daily or seasonal basis. But the many variations in provisions—such as term, volume, volume flexibility and penalties associated with failure to supply—mean there can be significant price differences between contracts.[27]

While contracts form the basis of most gas sales arrangements, a wholesale gas market operates in Victoria to facilitate gas sales to manage system imbalances and pipeline network constraints (box 8.1).

8.5.2 Joint marketing

Joint venture parties in gas production typically sell their gas through joint marketing arrangements under authorisation from the Australian Competition and Consumer Commission. More recently, some joint venture parties in new gas fields have undertaken

27 ACIL Tasman, 'Australia's natural gas markets: the emergence of competition?', essay in AER, *State of the energy market 2008*, Melbourne, 2008.

separate marketing. Santos has separately marketed gas from its interest in the Casino field (Otway Basin), for example, as has Woodside with its interest in the Geographe/Thylacine field (also in the Otway Basin).[28]

8.5.3 Scheduling and balancing

Wholesale market arrangements must account for the physical properties of natural gas and transmission pipelines:

- Unlike electricity, gas takes time to move from point to point. In Victoria, gas is typically produced and delivered within 6–8 hours because most demand centres are within 300 kilometres of gas fields. Gas delivered from the Cooper Basin into Sydney, or from the Carnarvon Basin into Perth, can take two to three days because the gas must be transported over much longer distances.
- Natural gas is automatically stored in pipelines (known as *linepack*). It can also be stored in depleted reservoirs or in liquefied form, which is economic only to meet peak demand or for use in emergencies.
- Natural gas pipelines are subject to pressure constraints for safety reasons. The quantity of gas that can be transported in a given period depends on the diameter and length of the pipeline, the maximum allowable operating pressure and the difference in pressure between the two ends.

These features make it essential that daily gas flows are managed. In particular, deliveries must be scheduled to ensure gas produced and injected into a pipeline system remains in approximate balance with gas withdrawn for delivery to customers. To achieve this, gas retailers and major users must estimate requirements ahead of time and nominate these to producers and pipeline operators, subject to any pre-agreed constraints on flow rates and pipeline capacity.

Each day, producers and storage providers inject the nominated quantities of gas into the transmission network for delivery to customers. There are typically short term variations between a retailer's nominated injections and their actual withdrawals from the system, creating imbalances. A variety of systems operate in Australia for dealing with physical imbalances, as well as financial settlements to address imbalances between the injections and withdrawals of particular shippers.

In most jurisdictions, pipeline operators manage physical balancing, while independent system operators manage financial settlements for imbalances. The Australian Energy Market Operator (AEMO) is the system operator in Victoria, New South Wales, the ACT and South Australia, while REMCo operates the Western Australian market. AEMO also operates a spot market in Victoria to manage gas balancing (box 8.1). Similar market arrangements are being developed for major gas hubs in eastern Australia (see section 8.7.3).

8.5.4 Secondary trading

There is some secondary trading in gas, whereby contracted bulk supplies are traded to alter delivery points and other supply arrangements. Types of secondary trade include backhaul and gas swaps.

Backhaul can be used for the notional transport of gas in the opposite direction to the physical flow in a pipeline. It is achieved by redelivering gas at a point upstream from the contracted point of receipt. Backhaul arrangements are used most commonly by gas fired electricity generators and industrial users that can cope with intermittent supplies.

A *gas swap* is an exchange of gas at one location for an equivalent amount of gas delivered to another location. Shippers may use swaps to deal with regional mismatches in supply and demand. Swaps can also help deal with physical limitations imposed by the direction or capacity of gas pipelines, and may delay the need to invest in new pipeline capacity.

Anecdotal evidence suggests swaps are reasonably common in Australia, but mostly conducted on a minor scale.[29] Origin Energy and the South West Queensland

28 NERA, *The gas supply chain in eastern Australia*, Report to the AEMC, Sydney, March 2008, p. 26.
29 Firecone Ventures, *Gas swaps*, Report prepared for the National Competition Council, Melbourne, 2006.

Gas Producers (SWQP) entered a major swap arrangement in 2004 to enable Origin Energy to meet supply obligations in south east Australia using gas produced by the SWQP in the Cooper Basin. In return, Origin Energy delivered gas from its central Queensland field to meet supply obligations of the SWQP, including to customers in Gladstone and Brisbane.[30]

8.5.5 Trading hubs

A gas hub is an interconnection point between gas pipelines, at which trading in gas and pipeline capacity may occur. In Australia, gas hubs include Moomba (South Australia), Wallumbilla (Queensland) and Longford (Victoria).

VicHub at Longford was established in 2003 and connects the Eastern Gas Pipeline, Tasmania Gas Pipeline and Victorian Transmission System. This connection allows for the trading of gas between New South Wales, Victoria and Tasmania. VicHub allows for the posting of public buy and sell offers, but is not a formal trading centre that provides brokering services.

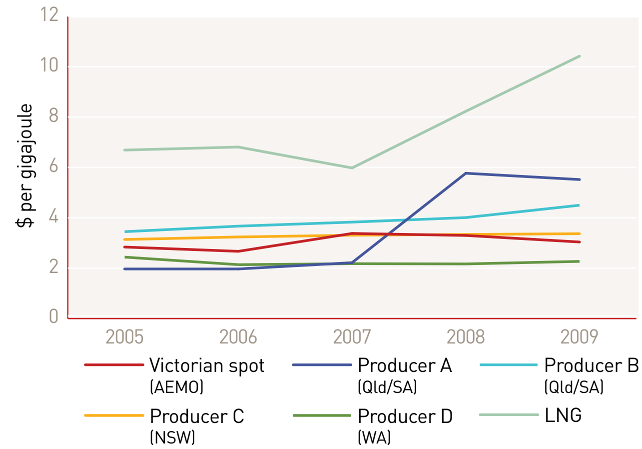
The establishment of the National Gas Market Bulletin Board in July 2008 and the development of a short term trading market at defined gas hubs (scheduled to commence by winter 2010) are likely to enhance market transparency and opportunities for gas trading at the major hubs of Sydney and Adelaide.

8.6 Gas prices

Australian gas prices have historically been low by international standards. They have also been relatively stable, defined by provisions in long term supply contracts. In the United States and Europe, gas prices closely follow oil prices. Conversely, natural gas in Australia has generally been perceived as a substitute for coal and coal fired electricity. Australia's abundant low cost coal sources have effectively capped gas prices.

Because gas contracts are not transparent outside Victoria, comprehensive price information is not widely available. Figure 8.12 sets out indicative data for domestic gas and LNG exports. The data relating to particular producers are based on average prices and, in some cases, may understate prices struck under new contracts.

Figure 8.12
Indicative wholesale natural gas prices



LNG, liquefied natural gas.

Notes:

Prices for the second quarter of the year (April–June).

Data for producers A, B, C and D are average company realisations for specific Australian gas producers.

Sources: EnergyQuest, *Energy Quarterly* (various editions); LNG data are sourced from the ABS.

Between 2005 and 2008 the following interacting factors put upward pressure on gas prices:

- A substantial rise in exploration, development and production costs flowed through to wholesale prices.
- Rising international energy prices, including for Australian LNG exports, increased domestic gas prices in Western Australia.
- Drought led to greater demand for gas fired generation in eastern Australia in 2007, with flow-on effects for gas prices.
- Market participants began factoring the projected effects of the Carbon Pollution Reduction Scheme into demand projections and pricing on long term gas contracts.[31]

Weaker economic growth—domestically and internationally—softened demand for natural gas in 2008 and 2009, and eased price pressure.

30 Details of the swap arrangement are provided in AER, *State of the energy market 2007*, box 8.4, Melbourne, 2007, p. 248.
31 ACIL Tasman, 'Australia's natural gas markets: the emergence of competition?', essay in AER, *State of the energy market 2008*, Melbourne, 2008, p. 30.

8.6.1 Western Australia

Western Australia experienced low domestic gas prices for several years as a result of competition between the North West Shelf Venture and smaller producers dedicated to the domestic market. Price pressure emerged around 2006 as rising demand for gas contracts—driven partly by the mining boom—occurred at a time when most producers had fully contracted their developed reserves. This was accompanied by substantial increases in gas field development costs.

At the same time, Western Australia's LNG export capacity has increased the domestic market's exposure to international energy prices. Average LNG prices received by Australian producers rose by 48 per cent between the June quarters of 2007 and 2008, and led to further escalation in domestic gas prices. The Western Australian Department of Industry and Resources reported that Santos secured domestic gas prices in July 2007 of more than $7 per gigajoule in two separate contracts.[32] Short term wholesale prices reached almost $17 per gigajoule in July 2008 following the Varanus Island incident, which cut domestic supply by around 30 per cent.[33]

International energy prices eased in 2008–09, given the effects of the global financial crisis on the manufacturing and industrial sectors. The average price received by Australian LNG producers in June quarter 2009 was $6.24 per gigajoule—down 24 per cent from the June quarter 2008 price of $8.17 per gigajoule. This was mirrored in a softening of price pressure in Western Australia's domestic market. EnergyQuest reported that some producers averaged prices in June quarter 2009 of between $2.26 and $4.84 per gigajoule (reflecting contracts of varying age and duration). One major producer, however, negotiated a four year contract with a mining customer at a price believed to be above $5.50 per gigajoule.[34] These price outcomes are generally lower than those recorded in 2007, but remain significantly higher than the typical prices of around $2.50 per gigajoule that prevailed in Western Australia earlier in the decade.

8.6.2 Eastern Australia

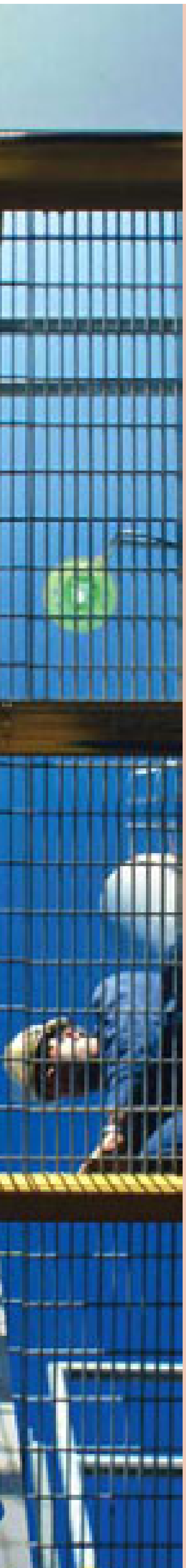
According to some published estimates, wholesale gas prices in Queensland rose from around $2.50–2.90 per gigajoule in 2006[35] to around $4 per gigajoule in 2008.[36] EnergyQuest reported mixed outcomes in 2008–09. One Queensland joint venture recorded average price realisations of $3.15 per gigajoule in June quarter 2009. On the east coast generally, one major producer recorded average prices of around $3.46 per gigajoule in June quarter 2009, compared with $3.12 in the equivalent period of 2008.[37]

While the development of CSG–LNG projects around Gladstone in the next few years may increase wholesale gas prices in the longer term, EnergyQuest projects that domestic prices may ease during the lengthy ramp-up of LNG export capacity.[38]

8.6.3 Victorian spot prices

The Victorian spot market (box 8.1) is Australia's only gas wholesale market that provides transparent price and volume data. The market is for sales of natural gas to balance daily requirements between retailers and suppliers. Market volumes can range from around 300 to 1200 terajoules per day. While the market accounts for only about 10–20 per cent of wholesale volumes in Victoria, its price outcomes are widely used as a guide to underlying contract prices.

32 Department of Industry and Resources (Western Australia), *Western Australian oil and gas review 2008*, Perth, 2008.
33 EnergyQuest, *Energy Quarterly*, August 2008.
34 EnergyQuest, *Energy Quarterly*, August 2009, p. 73.
35 Core Collaborative's *Australian gas sector outlook estimate* published in NERA, *The gas supply chain in eastern Australia*, Report to the AEMC, Sydney, March 2008, p. 36.
36 ACIL Tasman, 'Australia's natural gas markets: the emergence of competition?', essay in AER, *State of the energy market 2008*, Melbourne, 2008, p. 47.
37 EnergyQuest, *Energy Quarterly*, August 2009, p. 72.
38 EnergyQuest, 'Australia's natural gas markets: connecting with the world', essay in AER, *State of the energy market 2009*, Melbourne, 2009.



Box 8.1 The Victorian gas wholesale market

Victoria established a spot market for gas in 1999 to manage gas flows on the Victorian Transmission System (VTS). The market allows participants to trade gas supply imbalances (the difference between contracted gas supply quantities and actual requirements) on a daily basis. The Australian Energy Market Operator (AEMO), formerly VENCorp, operates both the wholesale market and the VTS.

Participants submit bids into the spot market on a daily basis via a market information bulletin board. Bids may range from $0 per gigajoule (the floor price) to $800 per gigajoule (the price cap). Following initial bidding at the beginning of the gas day (6 am), the bids may be revised four times a day at the scheduling intervals of 10 am, 2 pm, 6 pm and 10 pm.

Market participants (mostly retailers) inform AEMO of their nominations for gas one and two days ahead of requirements. At the beginning of each day, schedules are drawn up that set out the hourly gas injections into and withdrawals from the system. The schedules rely on information from market participants and AEMO, including demand forecasts, bids, weather conditions or supply constraints affecting bids, hedge nominations and AEMO's modelling of system constraints.

At the beginning of each day, AEMO stacks supply offers and selects the least cost bids to match demand across the market. This establishes a spot market clearing price. Given the Victorian market is a net market, this price applies only to net injections or withdrawals (the difference between contracted and actual amounts).

Overall, gas traded at the spot price accounts for around 10–20 per cent of wholesale volumes in Victoria, with the balance sourced via bilateral contracts or vertical ownership arrangements between producers and retailers.

In effect, the spot market provides a clearing house in which prices reflect short term supply–demand conditions, while underlying long term contracts insulate parties from price volatility. Nevertheless, a comparison of projected spot market prices with underlying contract prices allows a retailer to take a position to modify its own injections of gas and then trade gas at the spot price.

Sometimes, AEMO needs to schedule additional injections of gas (typically LNG) that have been offered at above market price to alleviate short term constraints. Market participants that inject the higher priced gas receive ancillary payments. These payments are recovered from uplift charges paid, as far as practicable, by the market participants whose actions resulted in a need for injections. A user's authorised maximum interval quantity (AMIQ) is a key allocation factor in determining who must contribute uplift payments to pay for this gas.

In particular, market participants that exceed their AMIQ on a day when congestion occurs may face an uplift charge, which provides a price signal to participants to adjust their gas use.

Market participants with AMIQ credits also have higher priority access to the pipeline system if congestion requires the curtailment of some users to maintain system pressure. This has not been necessary in recent years because sufficient gas (including LNG) has been available to support all users on the system. A party can acquire AMIQ certificates by injecting gas into the Victorian system at Longford or by entering a contract with the VTS owner, GasNet.

Until winter 2007 available gas and capacity on the VTS had been sufficient to meet customer requirements. Congestion occurred on only a few days a year, usually in winter. During winter 2007, however, there was a greater incidence of the market operator having to inject higher priced LNG to manage constraints and maintain minimum pressures. A key factor was that drought constrained the availability of coal fired and hydroelectric generation, resulting in greater reliance on gas fired generation and increased demand for natural gas.

With the easing of drought, a recent downturn in interstate gas demand, the commissioning of new pipeline capacity in 2008–09, and relatively mild weather, high cost injections of LNG were less necessary in the winter of 2009.

While Victorian spot prices are generally relatively stable, there are occasional troughs and spikes. On 22 November 2008, for example, the spot price rose from $3.50 per gigajoule at the beginning of the day to the price cap of $800 per gigajoule in the final trading interval, before falling to $5.75 per gigajoule at the start of the following gas day. According to AEMO, price spikes in the market have been mostly due to operational and market issues, often related to severe or unpredictable weather.

Further information on Victorian gas prices is set out in sections 8.6.3 and 8.7.4.

Figure 8.13 charts price and volume activity since the market started in 1999. Aside from a winter peaking demand profile, prices remained relatively stable until 2005. Volatility has since been greater, with significantly higher winter prices in 2006, 2007 and 2008. The market recorded its highest monthly price of almost $9 per gigajoule in July 2007, when drought caused an increase in demand for gas fired electricity generation. Spot prices peaked at $336 per gigajoule on 17 July 2007.

Prices later eased back towards trend levels, although the price cap of $800 per gigajoule was reached in the final scheduling interval on 22 November 2008. This outcome was due to a combination of planned and unplanned plant outages and higher than expected gas demand.

Gas prices have generally eased in 2009, reflecting a combination of factors:

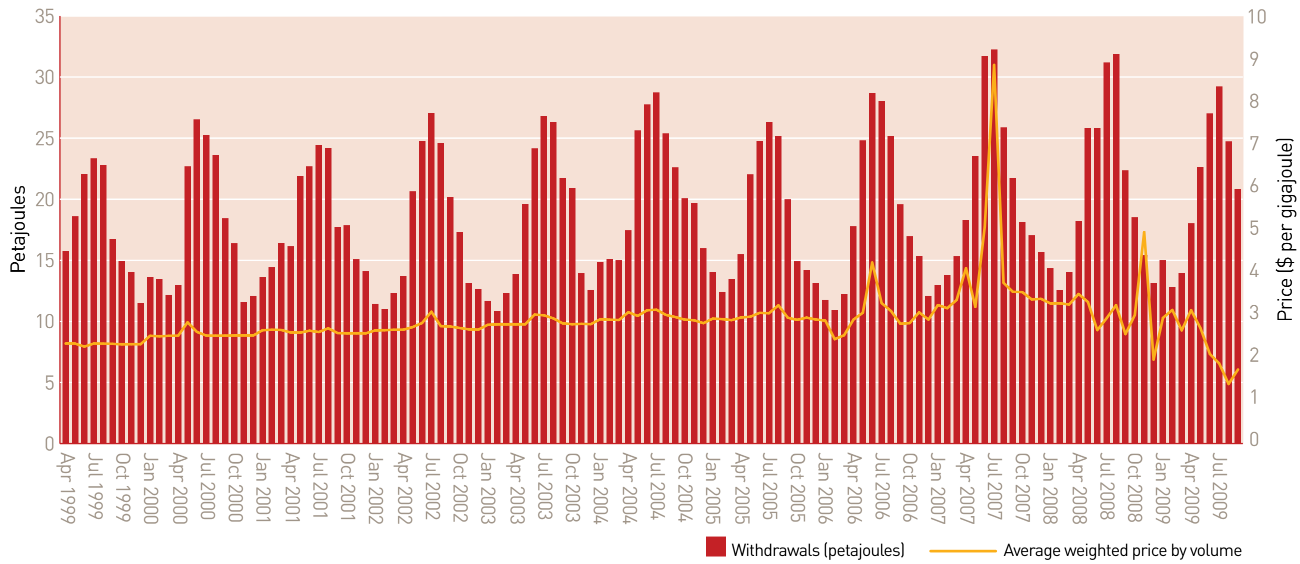
> An expansion of the Victorian Transmission System (completed in 2008) has eased capacity constraints on the network.
> An easing of the drought in 2008 led to a downturn in interstate demand for gas for electricity generation.
> A weaker economy and a relatively mild winter led to some easing of demand in 2009.

Victorian spot prices averaged $2.68 per gigajoule for June quarter 2009—down 19 per cent on the previous year's June quarter average. EnergyQuest reported that spot prices in June 2009 were below current contract prices.[39]

39 EnergyQuest, *Energy Quarterly*, August 2009, p. 73.

Figure 8.13

Victorian gas market—monthly prices and volumes



Note: Average monthly prices (right axis). Withdrawals are monthly totals (left axis).

Source: AEMO.

8.7 Gas market development

The Ministerial Council on Energy (MCE) in 2005 appointed a Gas Market Leaders Group to consider the need for further reform of the Australian gas market. In 2006 the group recommended establishing:

- a gas market bulletin board
- a short term trading market in gas
- a national gas market operator to administer the bulletin board and short term trading market, and to produce an annual national statement of opportunities on the gas market covering supply–demand conditions.

The National Gas Market Bulletin Board was launched on 1 July 2008, and there has been significant progress towards implementing the other initiatives. The reforms aim to improve transparency and efficiency in Australian gas markets. They also aim to provide information to help manage gas emergencies and system constraints.

8.7.1 Australian Energy Market Operator

As the single national energy market operator, AEMO commenced operation on 1 July 2009, replacing gas and electricity market operators such as VENCorp and the National Electricity Market Management Company. It operates the bulletin board and will operate the short term trading market from July 2010. It will also publish an annual Gas Statement of Opportunities (GSOO)—a national gas supply and demand statement similar to the annual Statement of Opportunities published for electricity.

The GSOO is intended to provide information to assist gas industry participants in their planning and commercial decisions on infrastructure investment. AEMO expects to publish the first GSOO in December 2009.

8.7.2 National Gas Market Bulletin Board

The bulletin board, which commenced on 1 July 2008, is a website covering major gas production plants, storage facilities, demand centres and transmission pipelines in southern and eastern Australia.[40] Provision has been made for Western Australia, the Northern Territory and facilities in north Queensland to participate in the future.[41]

The bulletin board aims to provide transparent, real-time and independent information to gas customers, small market participants, potential new entrants and market observers (including governments) on the state of the gas market, system constraints and market opportunities. Information provision by relevant market participants is mandatory and covers:

- gas pipeline capacity and daily aggregated data on expected gas volumes
- production capabilities (maximum daily quantities) and three day outlooks for production facilities
- storage capabilities and three day outlooks for storage facilities.

Participants may also advise of spare capacity and make offers through the bulletin board.

The bulletin board facilitates trade in gas and pipeline capacity by providing readily available system and market information. It provides, for example, information on outages and maintenance at production points, and on pipeline linepack.[42] It also provides daily demand forecasts, actual or expected changes in supply capacity to demand centres and, in the event of significant outages or system incidents, a flag indicating likely interruptions to customer supplies.

The bulletin board has been operated by AEMO since 1 July 2009. Under the National Gas Law, the AER monitors and enforces the compliance of market participants with the rules of the bulletin board.

8.7.3 Short term trading market

The Gas Market Leaders Group is developing a short term trading market in gas to commence in June 2010, following a trial from March 2010. The reform will create a day-ahead wholesale spot market in gas for balancing purposes. AEMO will operate the market, which will apply at nominated hubs or city gates. Initially, the market will operate only in Sydney and Adelaide. The MCE has flagged the potential for trading hubs to be established in Queensland and the ACT. The reform will not apply in Victoria, which has operated its own gas wholesale market since 1999 (box 8.1).

The rationale for the market stems from concerns that the gas balancing mechanisms in Sydney and Adelaide have caused barriers to retail market entry and impeded gas supply efficiency. In particular, the mechanisms have created substantial financial exposures that are disproportionate to underlying costs. New entrants have faced difficulties acquiring appropriate hedging to manage these risks. The issues have been especially pertinent for Sydney and Adelaide, which are sourced by multiple transmission pipelines.[43]

The new spot market will set a daily clearing price at each hub, based on bids by gas shippers to deliver additional gas. The market operator will then settle, at the clearing price, the difference between each user's daily deliveries and withdrawals of gas. The mechanism is aimed at providing transparent price signals to market participants to stimulate trading—including secondary trading—and demand-side response by users.

The short term trading market is intended to operate in conjunction with longer term gas supply and transportation contracts. It will provide an additional option for users to buy or sell gas on a spot basis without needing to enter delivery contracts in advance. It will also allow contracted parties to manage short term supply and demand variations to their contracted quantities.

40 National Gas Market Bulletin Board website (www.gasbb.com.au).

41 Western Australia created its own limited bulletin board, run by the Independent Market Operator, to assist with the Varanus Island gas emergency in 2008. Although low volumes of trade were reported, the bulletin board provided some indication of prices during this period of restricted supply.

42 'Linepack' refers to the amount of gas stored in a pipeline.

43 Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, *Final report of the Joint Working Group on Natural Gas Supply*, Canberra, September 2007, p. 19; McLennan Magasanik Associates, *Report to the Joint Working Group on Natural Gas Supply*, Melbourne, July 2007.

8.7.4 Futures markets

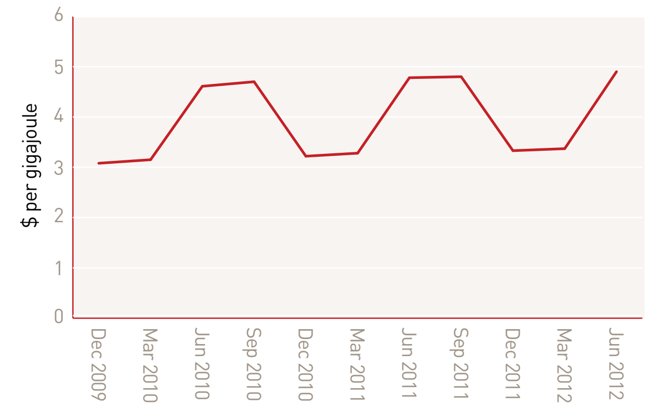
Participants in a commodity market can usually hedge their risk using physical or financial instruments. Internationally, gas futures markets tend to develop only after the underlying physical markets reach a certain level of maturity, with significant trading between buyers and sellers under transparent short term contracts.

The Sydney Futures Exchange introduced trading in Victorian wholesale gas futures and options on 21 July 2009. The market enables participants to plan and implement trading strategies, and provides hedge cover for new entrants. It also introduces a new asset class for financial market participants seeking diversity in their commodity portfolios, and allows arbitrage across the energy sectors.

Figure 8.14 illustrates Victorian gas futures prices at 30 September 2009 for December quarter 2009 through to June quarter 2012. The data indicate a general expectation of lower gas prices in the December and March quarters, when warmer weather eases demand for gas. In contrast, futures prices in the June and September quarters are well above $4 per gigajoule, with colder weather driving up gas demand for heating. Overall, there is a slight upward trend in prices over the next two to three years, with prices reaching $4.90 per gigajoule for June quarter 2012.

Rising demand for natural gas as a fuel for electricity generation, together with the proposed Carbon Pollution Reduction Scheme, bode well for the growth of gas futures markets in Australia. The short term trading market to commence from 2010 may encourage further development of hedge market instruments for gas.

Figure 8.14
Victorian gas futures market—quarterly prices



Source: SFE.

8.8 Reliability of supply

Reliability relates to the continuity of gas supply to customers. Various factors—planned and unplanned—can lead to outages that interrupt supply. These interruptions may occur in gas production facilities or in the pipelines that deliver gas to customers.[44] A planned outage may occur for maintenance or construction works, and can be timed for minimal impact. Unplanned outages occur when equipment failure causes the supply of gas to be interrupted.

A distinguishing feature of reliability issues in the gas sector compared with the electricity sector is the management of safety issues. While incidents such as gas explosions and fires at upstream facilities are rare, the risk of widespread damage and injury is serious. In extreme cases, an upstream gas incident may also lead to the load shedding of customers.

44 Section 10.7 of this report discusses reliability issues in the gas distribution sector.

Major upstream incidents occurred at Longford (Victoria) in 1998, Moomba (South Australia) in 2004 and Varanus Island (Western Australia) in 2008. Victoria experienced a major supply outage in 1998 following gas fires at the Longford gas plant, which killed two people and shut down the state's entire gas supply for three weeks. The incident created significant economic costs. There was limited pipeline interconnection in 1998, which restricted Victoria's ability to import gas from other states to alleviate the shortage.

An explosion at South Australia's Moomba gas plant in January 2004 caused a significant loss of production capacity from the Cooper Basin, which restricted gas supplies into New South Wales. The issue was managed partly by importing gas from Victoria along the Eastern Gas Pipeline (constructed in 2000).

The incidents at Longford and Moomba led Australian governments to agree in 2005 on protocols to manage major gas supply interruptions on the interconnected networks.[45] The agreement established a government–industry National Gas Emergency Response Advisory Committee to report on the risk of gas supply shortages, and on options for managing potential shortages. A working group developed a communications protocol and procedures manual that details instructions for officials and industry members in the event of an incident.

In the event of a major gas supply shortage, the protocol requires that commercial arrangements operate, as far as possible, to balance gas supply and demand and maintain system integrity. Emergency powers are available as a last resort. The Gas Market Bulletin Board includes a facility to support the emergency protocol. It can gather emergency information from relevant market participants and jurisdictions.

There were significant reliability issues in New South Wales and the ACT in June 2007 when capacity on the Eastern Gas Pipeline and gas flows on the Moomba to Sydney Pipeline were insufficient to meet higher than expected demand. While there was no infrastructure failure by gas producers or transmission pipeline operators, the New South Wales Government established a Gas Continuity Scheme in 2008 to mitigate the risk of a recurrence. The scheme provides commercial incentives for producers to increase supplies and for customers to reduce gas use in the event of a shortfall.

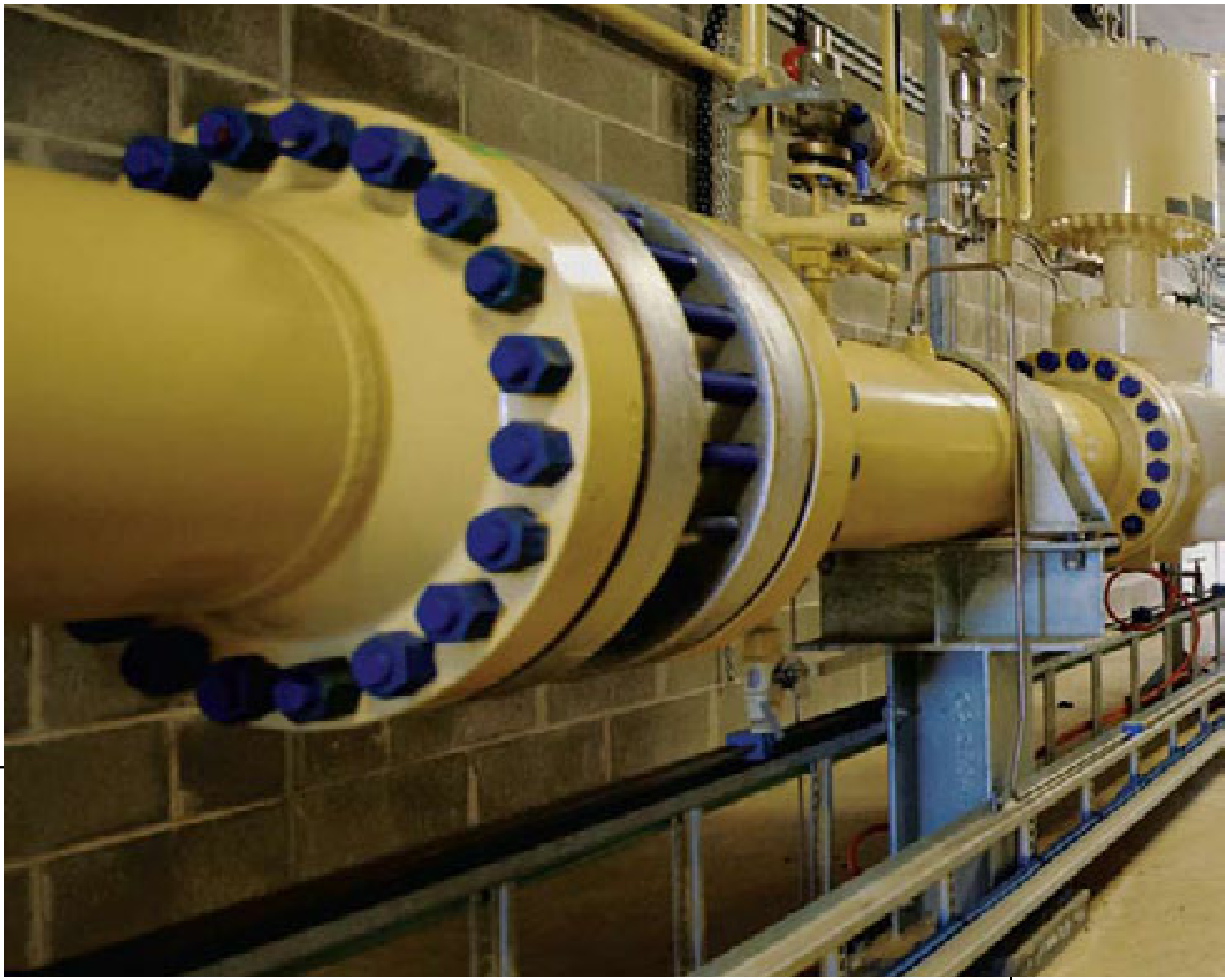
Western Australia's domestic gas supply was severely disrupted by an explosion at Varanus Island on 3 June 2008. The incident shut down Apache Energy's gas processing plant and reduced Western Australia's gas supply by around 30 per cent for over two months.

Spot prices for gas rose sharply as a result of the explosion. Limited gas supplies forced several mining and industrial companies to scale back production, and some electricity generators switched to emergency diesel stocks. Some coal fired power plants that had been closed were also brought back online. Western Australia's Independent Market Operator (which operates the state's wholesale electricity market) established a gas bulletin board to facilitate trading during the disruption.

The Western Australian Treasury estimated that the crisis cost the state economy $2 billion. It took 12 months to repair the Varanus Island facilities and return to pre-incident production rates.[46]

45 Memorandum of Understanding in Relation to National Gas Emergency Response Protocol (Including Use of Emergency Powers), June 2005 (available at www.mce.gov.au).

46 For further information on the Varanus Island incident, see EnergyQuest's essay in this report, section E.5.



9 GAS TRANSMISSION

Transmission pipelines transport natural gas from production fields to major demand centres. The pipelines typically have wide diameters and operate under high pressure to optimise shipping capacity. They are placed mainly underground, which helps to minimise damage that could pose safety issues and interrupt gas supplies. In total, Australia's gas transmission network covers over 20 000 kilometres.

9 GAS TRANSMISSION

This chapter considers:

- Australia's gas transmission sector
- the structure of the sector, including industry participants and ownership changes over time
- the economic regulation of the gas transmission sector
- new investment in transmission pipelines
- emerging competition in the gas transmission sector
- pipeline tariffs.

9.1 Australia's gas transmission pipelines

Australia's gas transmission pipeline network has almost trebled in length since the early 1990s. Around $4 billion has been invested or committed to new transmission pipelines and expansions since 2000.[1] Much of this investment has been in long haul interstate pipelines to introduce new supply sources and improve security of supply. The construction of Epic Energy's QSN Link (stage 1 completed in 2009) has interconnected the Queensland transmission network with major pipelines in South Australia and New South Wales.[2]

Earlier projects included the Eastern Gas Pipeline (Longford to Sydney, completed in 2000), the Tasmanian Gas Pipeline (Longford to Hobart, 2002) and the South East Australia Gas (SEA Gas) Pipeline (Port Campbell to Adelaide, 2003). The VicHub in eastern Victoria was constructed in 2002 to physically interconnect the Victorian Transmission System with the Tasmanian Gas Pipeline and the Eastern Gas Pipeline.

1 AER estimate comprising investment in new pipelines and major expansions (table 9.3) and regulatory approved investment in covered pipelines.

2 Previously, only a raw gas pipeline from Ballera to Moomba connected the Queensland and South Australian pipeline systems.

In combination, these projects have created an interconnected pipeline network covering Queensland, New South Wales, Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT).

The interconnection of the eastern jurisdictions has improved options to source gas from alternative gas basins. A retailer in Sydney, for example, can source natural gas from Queensland's Surat–Bowen Basin (using the QSN Link and Moomba to Sydney Pipeline), South Australia's Cooper Basin (using the Moomba to Sydney Pipeline) or Bass Strait (using the Eastern Gas Pipeline). These developments are enhancing the competitive environment for gas producers, pipeline operators and gas retailers and improve supply options in times of constrained production.

Transmission pipelines in Western Australia and the Northern Territory are not interconnected with other jurisdictions. The populated south west of Western Australia is serviced by the Dampier to Bunbury Pipeline, which delivers gas from the Carnarvon Basin. The smaller Parmelia Pipeline transports gas from both the Carnarvon and Perth basins. There has been substantial investment in Western Australian pipelines in the past decade, including major expansions of the Dampier to Bunbury Pipeline and new pipelines to supply gas to the mining and resources sector.

In the Northern Territory, the completion of the Bonaparte Pipeline in December 2008 introduced a second source of natural gas—from the Blacktip field—to compete with gas from the declining Mereenie and Palm Valley gas fields (which ship gas via the Amadeus Basin to Darwin Pipeline).

Table 9.1 sets out summary details of Australia's major transmission pipelines. Figure 9.1 illustrates pipeline routes.

9.2 Ownership of gas transmission pipelines

Government reforms to the gas sector in the 1990s led to structural reform and significant ownership changes. In particular, vertically integrated gas utilities were disaggregated and most government owned transmission pipelines were privatised. Figure 9.2 summarises changes in the ownership of major transmission pipelines since 1994.

Privatisation led to the entry of United States based utilities such as Epic Energy and Duke Energy. The principal domestic player was the New South Wales energy utility AGL, which owned or acquired major transmission assets in New South Wales and Queensland. In 2000 AGL's gas transmission assets were transferred to the Australian Pipeline Trust, which is now part of APA Group.[3]

Over time, the United States based utilities exited the Australian market, and new players such as Alinta took their place. Investment trusts such as Hastings and DUET Group also acquired transmission assets. The ownership landscape experienced a major shift in 2007 with the sale of Alinta to Singapore Power International and Babcock & Brown.[4]

Further consolidation has reduced the number of principal players in the gas transmission sector to four:

> *Singapore Power International* acquired a portfolio of gas transmission assets from Alinta in 2007, and rebranded them as *Jemena* in August 2008. It owns and operates the Eastern Gas Pipeline, VicHub and the Queensland Gas Pipeline, and operates the Tasmanian Gas Pipeline.

3 In 2006 the Australian Pipeline Trust began trading as part of APA Group, which comprises Australian Pipeline Ltd, the Australian Pipeline Trust and the APT Investment Trust.

4 The 2007 and 2008 editions of the AER's *State of the energy market* report detail the historical changes in the ownership of gas transmission infrastructure. The reports are available on the AER website: www.aer.gov.au.

Table 9.1 Major gas transmission pipelines

PIPELINE	LOCATION	LENGTH (KM)	CAPACITY (TJ/D)	CONSTRUCTED	COVERED?
NORTH EAST AUSTRALIA					
North Queensland Gas Pipeline	Qld	391	108	2004	No
Queensland Gas Pipeline (Wallumbilla to Gladstone)	Qld	629	79	1989–91	No
Carpentaria Pipeline (Ballera to Mount Isa)	Qld	840	117	1998	Yes (light)
Berwyndale to Wallumbilla Pipeline	Qld	113		2009	No
Dawson Valley Pipeline	Qld	47	30	1996	Yes
Roma (Wallumbilla) to Brisbane	Qld	440	208	1969	Yes
Wallumbilla to Darling Downs Pipeline	Qld	205	400	2009	No
South West Queensland Pipeline (Ballera to Wallumbilla)	Qld	756	168	1996	No
QSN Link (Ballera to Moomba)	Qld–SA and NSW	180	212	2009	No
SOUTH EAST AUSTRALIA					
Moomba to Sydney Pipeline	SA–NSW	2029	420	1974–93	Partial (light)
Central West (Marsden to Dubbo) Pipeline	NSW	255	10	1998	Yes
Central Ranges (Dubbo to Tamworth) Pipeline	NSW	300	7	2006	Yes
Eastern Gas Pipeline (Longford to Sydney)	Vic–NSW	795	250	2000	No
Victorian Transmission System (GasNet)	Vic	2035	1030	1969–2008	Yes
South Gippsland Natural Gas Pipeline	Vic	250		2006–10	No
VicHub	Vic		150 (into Vic)	2003	No
Tasmanian Gas Pipeline (Longford to Hobart)	Vic–Tas	734	129	2002	No
SEA Gas Pipeline (Port Campbell to Adelaide)	Vic–SA	680	314	2003	No
Moomba to Adelaide Pipeline	SA	1185	253	1969	No
WESTERN AUSTRALIA					
Dampier to Bunbury Pipeline	WA	1854	785	1984	Yes
Goldfields Gas Pipeline	WA	1427	150	1996	Yes
Parmelia Pipeline	WA	445	70	1971	No
Pilbara Energy Pipeline	WA	219	188	1995	No
Midwest Pipeline	WA	353	20	1999	No
Telfer Pipeline (Port Hedland to Telfer)	WA	443	25	2004	No
Kambalda to Esperance Pipeline	WA	350	6	2004	No
Kalgoorlie to Kambalda Pipeline	WA	44	20		Yes
NORTHERN TERRITORY					
Bonaparte Pipeline	NT	287	80	2008	No
Amadeus Basin to Darwin Pipeline	NT	1512	44	1987	Yes
Wickham Point Pipeline	NT	13		2009	No
Daly Waters to McArthur River Pipeline	NT	330	16	1994	No
Palm Valley to Alice Springs Pipeline	NT	140	27	1983	No

TJ/d, terajoules per day; CKI, Cheung Kong Infrastructure; REST, Retail Employees Superannuation Trust.

Notes:

Covered pipelines are subject to regulatory arrangements under the National Gas Law. The Australian Energy Regulator (AER) regulates covered pipelines outside Western Australia, where the Economic Regulation Authority is the transmission regulator.

For covered pipelines subject to full regulation, valuation refers to the opening capital base for the current regulatory period. For the Moomba to Sydney Pipeline, the Australian Competition Tribunal determined the valuation. For non-covered pipelines, listed valuations are estimated construction costs, subject to availability of data.

VALUATION ($ MILLION)	CURRENT ACCESS ARRANGEMENT	OWNER	OPERATOR
160 (2005)	Not required	Victorian Funds Management Corporation	AGL Energy, Arrow Energy
	Not required	Jemena (Singapore Power International (Australia))	Jemena Asset Management
	Not required	APA Group	APA Group
70 (2009)	Not required	AGL Energy	AGL Energy
8 (2007)	2007–16	Anglo Coal (51%), Mitsui (49%)	Anglo Coal
296 (2006)	2007–11	APA Group	APA Group
90 (2009)	Not required	Origin Energy	Origin Energy
	Not required	Epic Energy (Hastings)	Epic Energy
165 (2009)	Not required	Epic Energy (Hastings)	Epic Energy
835 (2003)	2004–09	APA Group	APA Group
28 (1999)	2000–10	APA Group	APA Group
53 (2003)	2005–19	APA Group	Country Energy (NSW Govt)
450 (2000)	Not required	Jemena (Singapore Power International (Australia))	Jemena Asset Management
524 (2007)	2008–12	APA Group	APA Group/AEMO
50 (2007)	Not required	Multinet Gas	Jemena Asset Management
	Not required	Jemena (Singapore Power International (Australia))	Jemena Asset Management
440 (2005)	Not required	Babcock & Brown Infrastructure	Jemena Asset Management
500 (2003)	Not required	International Power, APA Group and REST (equal shares)	APA Group
370 (2001)	Not required	Epic Energy (Hastings)	Epic Energy
1618 (2004)	2005–10	DUET Group (60%), Alcoa (20%), Babcock & Brown Infrastructure (20%)	WestNet Energy (Babcock & Brown Infrastructure)
514 (1999)	2000–09	APA Group (88.2%), Babcock & Brown Power (11.8%)	APA Group
	Not required	APA Group	APA Group
	Not required	Epic Energy (Hastings)	Epic Energy
	Not required	APA Group (50%), Horizon Power (WA Govt) (50%)	APA Group
114 (2004)	Not required	Energy Infrastructure Investments (APA Group 20%, Marubeni 50%, Osaka Gas 30%)	APA Group
45 (2004)	Not required	ANZ Infrastructure Services	WorleyParsons Asset Management
	None approved	APA Group	APA Group
170 (2008)	Not required	Energy Infrastructure Investments (APA Group 20%, Marubeni 50%, Osaka Gas 30%)	APA Group
229 (2001)	2001–11	Amadeus Pipeline Trust (APA Group 96%)	NT Gas (APA Group)
36 (2009)	Not required	Energy Infrastructure Investments (APA Group 20%, Marubeni 50%, Osaka Gas 30%)	APA Group
	Not required	APA Group, Power and Water	NT Gas (APA Group)
	Not required	Envestra (APA Group 31%, CKI 17%)	APA Group

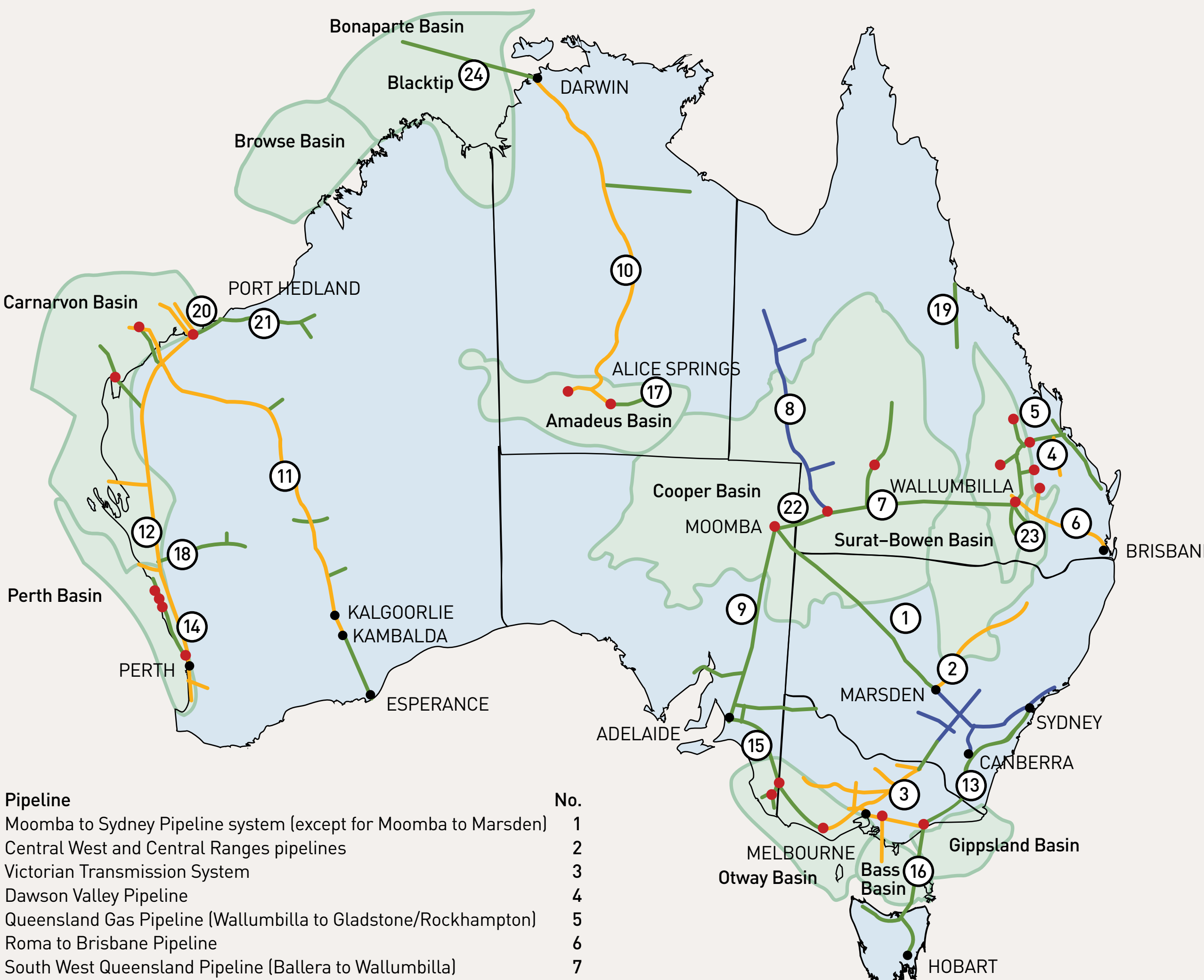
Coverage of the Moomba to Sydney Pipeline was partly revoked in 2003. The revoked portion runs from Moomba to the offtake point of the Central West Pipeline at Marsden (figure 9.1). The covered portion became a light regulation pipeline in 2008.

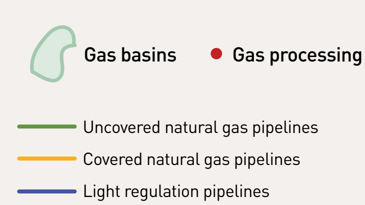
'Current access arrangement' refers to access terms and conditions approved by the regulator.

Some corporate names have been abbreviated or shortened.

Sources: Capacity: Office of Energy (Western Australia); National Gas Market Bulletin Board (www.gasbb.com.au); EnergyQuest, *Energy Quarterly*, August 2009; corporate websites. Other data: access arrangements for covered pipelines; EnergyQuest, *Energy Quarterly*, August 2009; ABARE, *Major development projects*, April 2009; corporate websites, annual reports and media releases.

Figure 9.1
Major gas transmission pipelines

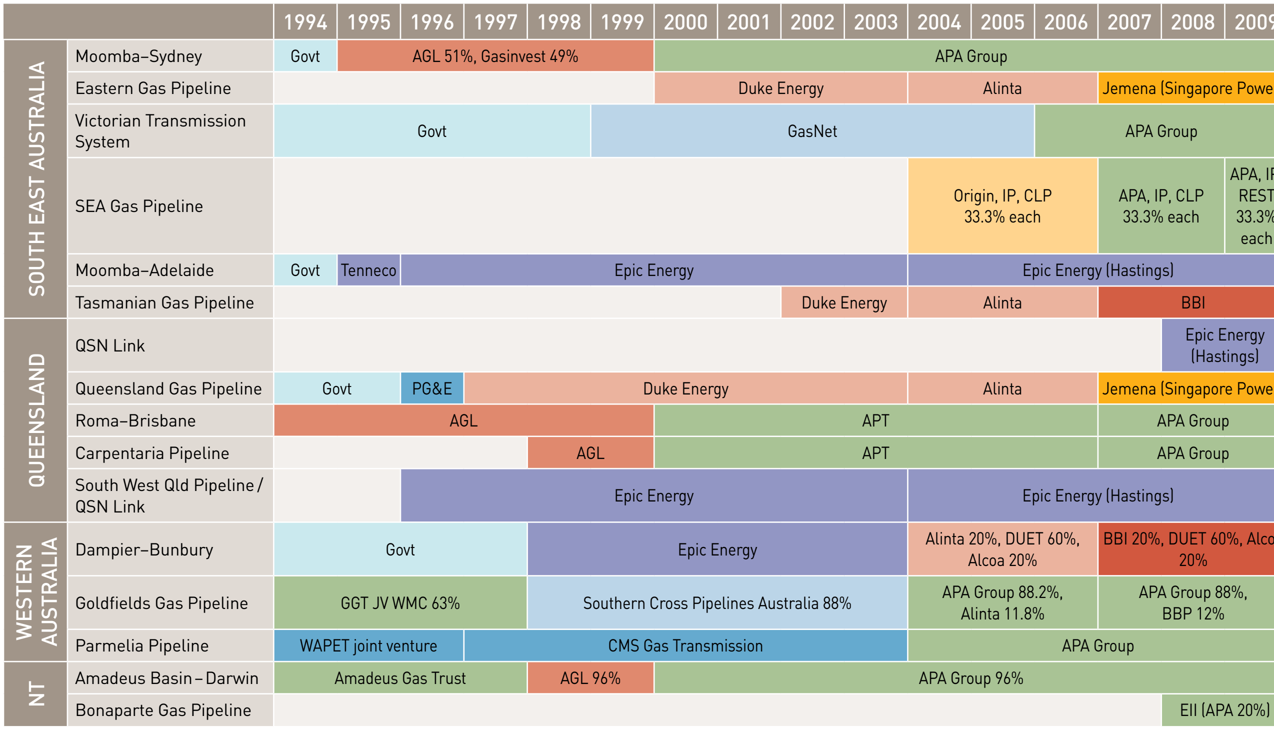




Pipeline	No.
Moomba to Sydney Pipeline system (except for Moomba to Marsden)	1
Central West and Central Ranges pipelines	2
Victorian Transmission System	3
Dawson Valley Pipeline	4
Queensland Gas Pipeline (Wallumbilla to Gladstone/Rockhampton)	5
Roma to Brisbane Pipeline	6
South West Queensland Pipeline (Ballera to Wallumbilla)	7
Carpentaria Pipeline (Ballera to Mount Isa)	8
Moomba to Adelaide Pipeline system	9
Amadeus Basin to Darwin Pipeline	10
Goldfields Gas Pipeline	11
Dampier to Bunbury Natural Gas Pipeline	12
Eastern Gas Pipeline (Longford to Horsley Park)	13
Parmelia Pipeline	14
SEA Gas Pipeline	15
Tasmanian Gas Pipeline	16
Palm Valley to Alice Springs Pipeline	17
Midwest Pipeline	18
North Queensland Gas Pipeline	19
Pilbara Pipeline	20
Telfer Pipeline	21
QSN Link	22
Berwyndale to Wallumbilla Pipeline	23
Bonaparte Pipeline	24

Source: AER.

Figure 9.2
Transmission pipeline ownership



APT, Australian Pipeline Trust (assets now part of APA Group); BBI, Babcock & Brown Infrastructure; BBP, Babcock & Brown Power; CKI, Cheung Kong Infrastructure; EII, Energy Infrastructure Investments; GGT JV, Goldfields Gas Pipeline Joint Venture; IP, International Power; WMC, Western Mining Company; PG&E, Pacific Gas and Electric; REST, Retail Employees Superannuation Trust; WAPET, West Australian Petroleum Pty Limited joint venture.

Notes:

Some corporate names have been abbreviated or shortened.

From 1996–2003 Epic Energy was owned by El Paso Energy (30%), CNG International (30%), Allgas Energy (10%), AMP Investments (10%), Axiom Funds Management (10%) and Hastings (10%).

In 2008 Singapore Power International rebranded its gas transmission assets as Jemena.

Sources: AER; Australian Gas Association, *Gas statistics Australia*, Melbourne (various years); corporate reports and websites.

> *APA Group* owns the Moomba to Sydney, Central West and Central Ranges pipelines in New South Wales; the Victorian Transmission System; two major Queensland pipelines (Carpentaria and Roma to Brisbane); three major Western Australian pipelines (Goldfields, Parmelia and Midwest); and a major Northern Territory pipeline (Amadeus Basin to Darwin). It also part owns the SEA Gas Pipeline and other Northern Territory pipelines.
  In December 2008 APA Group sold the Bonaparte and Wickham Point pipelines (Northern Territory) and Telfer Gas Pipeline (Western Australia) into an unlisted investment vehicle, Energy Infrastructure Investments Pty Limited (EII). Marubeni Corporation (50 per cent stake) and Osaka Gas (30 per cent) have majority equity. APA Group retains a 20 per cent equity interest and continues to operate the assets.

> *Babcock & Brown Infrastructure* acquired a 20 per cent interest in the Dampier to Bunbury Pipeline from Alinta in 2007. It now operates the pipeline through its management services business WestNet Energy. It also owns the Tasmanian Gas Pipeline and has a minority interest in Western Australia's Goldfields Gas Pipeline.

- *Hastings Diversified Utilities Fund*, managed by a fund acquired by Westpac in 2005, acquired *Epic Energy*'s gas transmission assets in 2000. It owns the Moomba to Adelaide Pipeline (South Australia), the Pilbara Energy Pipeline (Western Australia) and the South West Queensland Pipeline. In 2009 Epic Energy completed stage 1 of the QSN Link from Queensland to South Australia and New South Wales. In 2009 Hastings called for expressions of interest for the sale of part or all of Epic Energy. Hastings reported on 26 June 2009 that the sale process was continuing.

Other players include:
- DUET Group, the majority owner (60 per cent) of the Dampier to Bunbury Pipeline[5]
- International Power and the Retail Employees Superannuation Trust, each of which have ownership interests in the SEA Gas Pipeline
- AGL Energy, which owns the Berwyndale to Wallumbilla Pipeline (commissioned in 2009) but has announced plans for its sale
- Origin Energy, which owns the Wallumbilla to Darling Downs Pipeline (commissioned in 2009).

Earlier this decade, the ownership and operation (management control) of gas transmission pipelines tended to be separate, but more recently this pattern has reversed. In particular, APA Group and Jemena have moved to an integrated model, whereby a group entity operates and manages all pipeline assets owned or partially owned in the group. The Epic Energy (Hastings) pipelines continue to be operated by group management companies. Babcock & Brown Infrastructure uses a mix of in-house and outsourced asset management approaches.

9.3 Economic regulation of gas transmission pipelines

Gas transmission pipelines are capital intensive and incur declining marginal costs as output increases. This gives rise to a natural monopoly industry structure. Rising demand can usually be accommodated more cheaply by adding compressors or looping (duplicating part or all of) an existing pipeline than by constructing additional pipelines.

The National Gas Law (Gas Law) and National Gas Rules (Gas Rules) provide the overarching regulatory framework for the gas transmission sector. The Gas Law and Gas Rules commenced on 1 July 2008 in all jurisdictions except Western Australia, which expects to implement the pipeline access provisions in the second half of 2009. These instruments replace the Gas Pipelines Access Law and the National Gas Code (Gas Code), which had provided the national regulatory framework from 1997.

On 1 July 2008 the Australian Energy Regulator (AER) replaced the Australian Competition and Consumer Commission (ACCC) as the regulator for pipelines outside Western Australia. The Economic Regulation Authority of Western Australia is the regulator of covered pipelines in that state.

The Gas Law and Gas Rules apply to covered pipelines (see section 9.3.1). There are different forms of economic regulation for covered pipelines, based on criteria set out in the law (see section 9.3.2).

9.3.1 Which pipelines are regulated?

The Gas Pipelines Access Law applied to most Australian transmission pipelines initially, but this coverage changed over the past decade. Significant new investment in gas pipelines has led to improved interconnection between gas basins and retail markets in the southern and eastern states. This interconnection has increased supply options and, in some instances, may limit the ability of pipeline operators to exercise market power.

The Gas Law anticipates the potential for market conditions to evolve, and includes a coverage mechanism to allow for an independent review of whether there is a need to regulate a particular pipeline. The National Competition Council is the coverage review body, but designated government ministers make final decisions.

5 DUET Group comprises a number of trusts, for which Macquarie Bank (50%) and AMP Capital Holdings (50%) jointly own the responsible entities.

The decisions are open to review by the Australian Competition Tribunal, and in 2001 the tribunal reversed a ministerial decision to cover the Eastern Gas Pipeline.[6]

The coverage process has led to the lifting of economic regulation—in whole or part—from several major pipelines, including the Eastern Gas Pipeline, Western Australia's Parmelia Pipeline, the Moomba to Adelaide Pipeline and a significant portion of the Moomba to Sydney Pipeline. The Queensland Government passed legislation in 2008 that revoked the coverage of two major pipelines: the South West Queensland and Queensland Gas pipelines.[7]

The Gas Law includes a process to allow newly constructed pipelines to be covered. Only one pipeline constructed in the past decade (the Central Ranges Pipeline in New South Wales) is currently covered. Other new pipelines—including the SEA Gas and Tasmanian Gas pipelines and several new pipelines in Western Australia—are not covered. At July 2008 no transmission pipeline into Adelaide or Hobart was subject to economic regulation.

The service provider[8] of a covered pipeline must comply with the provisions of the Gas Law and Gas Rules. Pipelines that are not covered are subject only to the general anti-competitive provisions of the *Trade Practices Act 1974* (Cwlth). Access to non-covered pipelines is a matter for the access provider and an access seeker to negotiate, without regulatory assistance.

Table 9.1 indicates the coverage status of each major pipeline. At 1 July 2009 11 gas transmission pipelines were covered under the Gas Law (table 9.2). Of these, nine were subject to full regulation and two were subject to light regulation (see section 9.3.2).

In 2008 the Gas Law introduced incentives for investment in greenfields pipelines and international pipelines to Australia. Pipeline owners can apply for a determination that provides a 15 year exemption from coverage for greenfields pipelines and a 15 year exemption from price regulation for international pipelines.

Table 9.2 Covered transmission pipelines, September 2009

JURISDICTION AND PIPELINE	COMMENTS
NEW SOUTH WALES	
Moomba to Sydney Pipeline	Partially covered; light regulation of covered portion since 2008[1,2]
Central West Pipeline (Marsden to Dubbo)	Covered since 1998[3]
Central Ranges Pipeline	Covered since May 2004[4]
VICTORIA	
Victorian Transmission System	Covered since 1997
QUEENSLAND	
Roma (Wallumbilla) to Brisbane Pipeline	Covered since 1997; derogations expired in 2006, enabling the regulator to set tariffs for the first time
Dawson Valley Pipeline	Coverage revoked in 2000 but re-instated in 2006
Carpentaria Pipeline (Ballera to Mount Isa)	Covered since 1997; light regulation since 2008[2]
WESTERN AUSTRALIA[5]	
Dampier to Bunbury Pipeline	Covered since 1999
Goldfields Gas Pipeline	Covered since 1999
Kalgoorlie to Kambalda Pipeline[6]	Covered since 1999
NORTHERN TERRITORY	
Amadeus Basin to Darwin Pipeline	Covered since 1997

1. Coverage of the Moomba to Sydney Pipeline was partly revoked in 2003. The revoked portion runs from Moomba to the offtake point of the Central West Pipeline at Marsden (figure 9.1). The covered portion (Marsden to Wilton) became a light regulation pipeline in 2008.
2. The service provider of a light regulation pipeline must publish the terms and conditions of access, including tariffs, on its website. It is not required to submit an access arrangement to the regulator for approval.
3. The service provider of the Central West Pipeline lodged an application in October 2009 to convert to light regulation.
4. Under the National Gas Law, the Central Ranges Pipeline will cease to be covered once the current access arrangement expires.
5. The Gas Code commenced in Western Australia in 1999.
6. The regulator has not approved an access arrangement for this pipeline.

6 The Eastern Gas Pipeline was covered by a ministerial decision on 16 October 2000. The Australian Competition Tribunal reversed this decision on 4 May 2001.

7 Any party may apply to the National Competition Council to consider whether a previously covered pipeline should be covered again. The Dawson Valley Pipeline was revoked from coverage in 2000, but a later application reversed this decision in 2006 (table 9.2). The National Gas (Queensland) Regulation 2008 provided that no person may apply to reactivate coverage of the South West Queensland Pipeline for a period of one year, or the Queensland Gas Pipeline for a period of two years.

8 The service provider may be the controller, owner or operator of the whole pipeline or any part of the pipeline.

9.3.2 Regulatory framework

In Australia, the providers of most gas transmission pipelines negotiate contracts to sell transportation services to customers such as energy retailers. The contracts, which set the terms and conditions of third party access, are negotiated on commercial terms that may differ from those set through regulatory processes. A contract typically features a maximum daily quantity allocation and sets a capacity charge, which must be paid regardless of the amount of gas that a customer transports on the pipeline.

In Victoria, an independent operator—the Australian Energy Market Operator (AEMO)—manages the Victorian Transmission System, and users are not required to enter contracts. Instead, a party's daily gas flow is determined by its bids into the wholesale gas market. The bids enter a market clearing engine, which dispatches the lowest priced supply offers to meet demand. Pipeline charges are based on actual gas flows following this dispatch process.

Different forms of economic regulation apply to covered pipelines, based on criteria under the Gas Law.[9] Nine transmission pipelines are subject to *full regulation*, which requires the service provider to submit an access arrangement to the regulator for approval. The AER is the transmission pipeline regulator, except in Western Australia.[10] An access arrangement sets out the terms and conditions under which third parties can use a pipeline. It must specify at least one reference service that most customers seek, and a reference tariff for that service.

The reference tariff is intended as a basis for negotiation between the pipeline owner and customers. Typically, reference tariffs apply to firm forward haulage services, which are commonly sought on most pipelines.[11] A pipeline may also provide non-reference services, for which the AER does not approve the terms and conditions of access. Gas users seeking access to non-reference services, such as short term or interruptible supply, can try to directly negotiate those services with the pipeline operator or other gas shippers.

An access arrangement must also set out non-price terms and conditions, such as a capacity expansion policy, queuing requirements and gas quality specifications.[12] More generally, an access arrangement must comply with the provisions of the Gas Law, including pricing principles, ring-fencing requirements and provisions for associate contracts. In the event of a dispute, an access seeker may ask the regulator to arbitrate and enforce the provisions of an access arrangement.[13] The AER has published a guideline on dispute resolution under the Gas Law.[14]

The Gas Law establishes a process that may allow a pipeline to convert to *light regulation* without upfront price regulation. The National Competition Council determines whether a pipeline is subject to light regulation. The policy intent is that this form of regulation suits some transmission pipelines.[15] Where light regulation applies, the pipeline provider must publish access prices and other terms and conditions on its website. In the event of a dispute, an access seeker may ask the regulator to arbitrate.

The current light regulation pipelines are the Carpentaria Gas Pipeline in Queensland and the covered portions of the Moomba to Sydney Pipeline (table 9.2).[16]

9 The AER published an *Access arrangement guideline* in March 2009, which sets out the forms of regulation (see part 2 of the guideline). The guideline is available on the AER website at www.aer.gov.au.

10 The Economic Regulation Authority is the transmission regulator in Western Australia.

11 Firm forward haulage services enable the customer to reserve capacity on a pipeline and receive a high priority service. Interruptible services are sold on an 'as available' basis and may be interrupted or delayed, especially if a pipeline has capacity constraints.

12 For further information on non-price matters, see AER, *Access arrangement guideline, final*, Melbourne, March 2009, at s. 5.4.1.

13 In Western Australia, a separate arbitrator hears access disputes.

14 AER, *Guideline for the resolution of distribution and transmission pipeline access disputes under the National Gas Law and National Gas Rules, final*, Melbourne, November 2008.

15 The Second Reading Speech for the National Gas (South Australian) Bill 2008 (p. 15) indicates that light regulation may be relevant for point-to-point transmission pipelines with a small number of users, of whom each has countervailing market power.

16 The service provider of the Central West Pipeline lodged an application in October 2009 to convert to light regulation.

9.3.3 Regulatory process

For a pipeline subject to full regulation, the Gas Law requires the provider to submit an initial access arrangement to the regulator and periodically revise it. The revisions generally occur once every five years as scheduled reviews, but can occur more frequently—for example, if a trigger event compels an earlier review, or if the service provider seeks a variation to the access arrangement.

The Gas Rules prescribe the process and timeframe for an access arrangement review. The arrangements are identical to those for gas distribution pipelines. Section 10.4.3 of this report outlines the key elements; the AER published an *Access arrangement guideline* in March 2009, which details these processes.

9.3.4 Regulatory approach

The Gas Rules require the use of a building block approach to determine total revenue and derive tariffs. Total revenue must be sufficient to allow a business to recover efficient costs, including operating costs, taxation, asset depreciation and a return on capital (using a benchmark cost of capital). The Gas Rules also allow for income adjustments from incentive mechanisms that reward efficient operating practices. Tariffs are typically adjusted annually for inflation, and in some cases other factors.[17]

In approving a reference tariff, the AER must consider the costs of a prudent and efficient service provider of a pipeline service. In doing so, it will look at the circumstances in which a pipeline operates and draw on expert assessments, submissions from interested parties, benchmarking, the operation of efficiency mechanisms, and key performance indicator information.

Figures 9.3 and 9.4 show the revenue components under access arrangements for the Victorian Transmission System and the Roma to Brisbane Pipeline. They provide a guide to the typical composition of the revenue components in a determination. In these decisions, depreciation and returns on capital account for almost three quarters of revenue. Operating and maintenance costs account for most of the balance.

For pipelines subject to full economic regulation, the Gas Law sets a test to assess whether new investment may be rolled into the capital base.[18]

9.4 Recent gas pipeline investment

Investment in the gas transmission sector typically involves large and lumpy capital projects to expand existing pipelines (through compression, looping and extensions) or construct new pipelines.[19] Around $4 billion has been invested or committed to new transmission pipelines and expansions since 2000.[20] This amount reflects both real investment in new infrastructure and rising resource costs in the construction sector.

Table 9.3 provides summary information on major transmission pipeline investment since 2000. It also lists a selection of pipelines (or expansions) under construction and major pipelines that have been announced for future development.

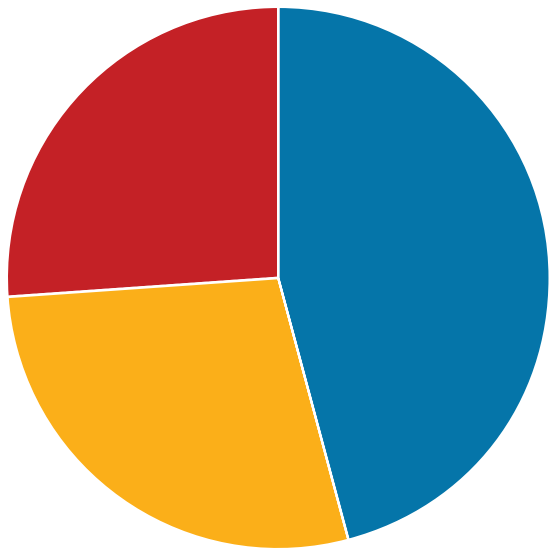
17 For further information on reference tariffs, see AER, *Access arrangement guideline, final*, Melbourne, March 2009, at s. 5.4.2.

18 The test allows for capital expenditure to be rolled into the regulated capital base if (1) the overall economic value is positive, (2) the present value of incremental revenue is greater than the present value of the capital expenditure or (3) the expenditure is necessary to maintain and improve service safety, or maintain service integrity, or maintain a service provider's capacity to meet levels of demand for existing services.
In determining the overall economic value, only the economic value directly accruing to the service provider, gas producers, users and end users is to be considered. There are additional criteria for capital expenditure for Western Australian transmission pipelines, which reflect the value that may directly accrue to electricity market participants from additional gas fired generation capacity.
According to the Second Reading Speech, National Gas (South Australian) Bill 2008, the test is 'designed to capture net increases in producer and consumer surpluses in upstream and downstream gas markets, while also capturing the system security and reliability benefits that were considered by regulators to constitute system wide benefits. The test … unambiguously includes benefits that accrue to users and end users of gas when they are able to purchase additional quantities of gas, or to gas producers when they are able to sell additional quantities of gas' (p. 18).

19 Pipeline capacity can be increased by adding compressor stations to raise the pressure under which gas flows and by looping (duplicating) sections of the pipeline. Extending the length of the pipeline can increase line pack (storage) capacity.

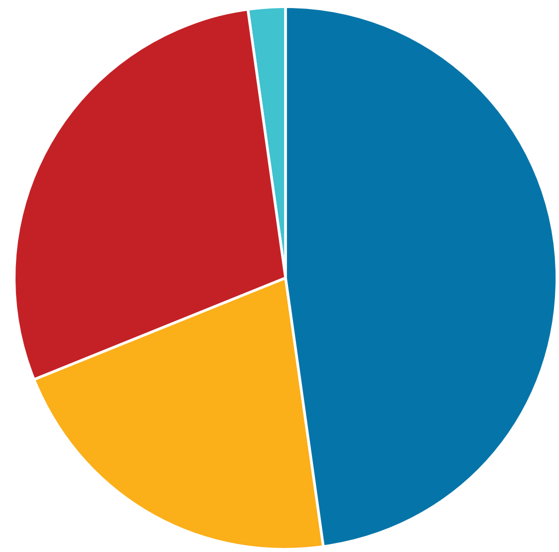
20 AER estimate comprising investment in new pipelines and major expansions (table 9.3) and regulator approved investment in covered pipelines.

Figure 9.3
Revenue composition for the Victorian Transmission System, 2008–12



Source: ACCC, *Revised access arrangement by GasNet Australia Ltd for the principal transmission system, final decision*, Canberra, 30 April 2008.

Figure 9.4
Revenue composition for the Roma to Brisbane Pipeline, 2007–11



Source: ACCC, *Revised access arrangement by APT Petroleum Pipelines Ltd for the Roma to Brisbane Pipeline, final decision*, Canberra, 20 December 2006.

Substantial investment in transmission pipelines in south east Australia occurred between 2000 and 2005. The new pipelines helped develop an interconnected system linking New South Wales, Victoria, South Australia, Tasmania and the ACT. More recently, the focus for new investment has shifted to north east Australia, the Northern Territory and Western Australia.

9.4.1 North east Australia

The development of Queensland's coal seam gas (CSG) industry has spurred significant new pipeline investment. Epic Energy commissioned the QSN Link (Ballera to Moomba) in January 2009, and has expanded capacity on the South West Queensland Pipeline to 170 terajoules per day. The QSN Link creates the ability, for the first time, to deliver dry gas between Queensland and the southern states. The expansion of the South West Queensland Pipeline allows increased flows of CSG from Queensland's Surat–Bowen basin to south east Australia via the QSN Link.

In December 2007 Epic Energy announced plans for a $64 million expansion of the QSN Link and a further (stage 2) expansion of the South West Queensland Pipeline (to 220 terajoules a day) by 2013, to deliver gas for AGL Energy. In June 2009 it announced a conditional agreement with Origin Energy for a further $760 million expansion of the South West Queensland Pipeline to 380 terajoules per day. The stage 3 expansion would effectively duplicate the existing pipeline.

Other Queensland pipelines are also being expanded. In 2009 APA Group completed a 15 per cent capacity expansion of the Carpentaria Pipeline. Jemena has announced a $112 million expansion of the Queensland Gas Pipeline (Wallumbilla to Gladstone) by 2010. The expansion will increase the pipeline's capacity from 79 to 133 terajoules per day.

In addition to the QSN Link, two other major pipelines were commissioned in Queensland in 2009:

- AGL Energy commissioned the $70 million Berwyndale to Wallumbilla Pipeline. The pipeline allows delivery of CSG from Queensland's Surat–Bowen Basin to the Wallumbilla hub, from which it can be shipped west along the South West Queensland Pipeline to southern markets, or east along the Roma to Brisbane Pipeline to meet gas demand around Brisbane.
- Origin Energy completed a $90 million pipeline to ship gas from Wallumbilla to the gas fired Darling Downs power station it is constructing.

Planned development of liquefied natural gas (LNG) projects in Queensland has also spurred plans to develop new transmission infrastructure to transport CSG to Gladstone for LNG processing. Among the proposals are:

- Santos's 432 kilometre Gladstone LNG Pipeline (Fairview to Gladstone), scheduled for commissioning by 2014
- Arrow Energy's $500 million Surat Basin to Gladstone Pipeline (450 kilometres).

9.4.2 South east Australia

Several major transmission pipelines were developed in south east Australia between 2000 and 2005. These included the Eastern, Tasmanian and SEA Gas pipelines (table 9.3). More recently:

- Multinet began a four year project to develop the South Gippsland Natural Gas Pipeline in 2006. The $50 million project comprises transmission and distribution infrastructure to provide reticulated natural gas to 10 000 properties in south east Victoria.
- APA Group completed a $70 million extension of the Victorian Transmission System in 2008 with the Lara to Brooklyn Pipeline (the Corio loop). The loop facilitates gas flow from the Otway Basin to Melbourne.

The owners of the two transmission pipelines serving Sydney have each announced capacity expansions:

- APA Group in 2008 began a $100 million five year expansion program for the Moomba to Sydney Pipeline, which will increase capacity by around 20 per cent. The expansion will increase gas flows for new gas fired electricity generation projects such as Uranquinty near Wagga Wagga.
- Jemena has announced a $41 million capacity expansion of the Eastern Gas Pipeline (Longford to Sydney), to be completed by 2010.

9.4.3 Western Australia

In Western Australia, new investment activity has centred on major capacity expansions of the Dampier to Bunbury Pipeline, which is the major link between the state's North West Shelf and gas markets around Perth:

- The $430 million stage 4 expansion (completed in December 2006) involved eight new compressors and over 200 kilometres of looping.
- The $660 million stage 5A expansion (completed in March 2008) comprised 570 kilometres of looping and added capacity of around 100 terajoules per day. At the completion of stage 5A, around 50 per cent of the pipeline had been duplicated.
- In 2008 the pipeline owners announced a $690 million stage 5B expansion to add a further 113 terajoules per day of capacity. The latest expansion, set for completion in 2010, will involve a further 440 kilometres of looping. At the completion of stage 5B, around 94 per cent of the pipeline will have been duplicated.

Also in Western Australia, APA Group completed a 20 per cent expansion of the Goldfields Gas Pipeline in 2009.

9.4.4 Northern Territory

In the Northern Territory, APA Group completed the $170 million Bonaparte Gas Pipeline in 2008. The 287 kilometre pipeline transports natural gas for domestic supply from the Blacktip field in the Bonaparte Basin. It provides an alternative to gas supply from the declining Palm Valley and Mereenie fields. APA Group sold the pipeline into an unlisted investment vehicle, Energy Infrastructure Investments, in 2008.

Table 9.3 Major gas transmission pipeline investment since 2000

PIPELINE	LOCATION	OWNER/PROPONENT	SCALE	COST ($ MILLION)	COMPLETION DATE
COMPLETED					
NORTH EAST AUSTRALIA					
Wallumbilla to Darling Downs Pipeline	Qld	Origin Energy	205 km	90	2009
Berwyndale to Wallumbilla Pipeline	Qld	AGL Energy	113 km	70	2009
South West Queensland Pipeline—stage 1	Qld	Epic Energy	Expansion to 170 TJ/d	165	2009
QSN Link—stage 1	Qld–SA and NSW	Epic Energy	180 km, 250 TJ/d		
Carpentaria Pipeline	Qld	APA Group	15% expansion to 117 TJ/d		2009
North Queensland Gas Pipeline (Moranbah to Townsville)	Qld	Victorian Funds Management Corporation	391 km	160	2005
SOUTH EAST AUSTRALIA					
Corio Loop (expansion of Victorian Transmission System)	Vic	APA Group	57 km	70	2008
South Gippsland Natural Gas Pipeline	Vic	Multinet Gas	250 km	50	2009
Tasmanian Gas Pipeline (Longford to Hobart)	Vic–Tas	Babcock & Brown Infrastructure	734 km	440	2002–05
VicHub	Vic	Singapore Power International			2003
SEA Gas Pipeline (Port Campbell to Adelaide)	Vic–SA	International Power, APA Group, Retail Employees Superannuation Trust (equal shares)	680 km	500	2003
Eastern Gas Pipeline (Longford to Sydney)	Vic–NSW	Singapore Power International	795 km	450	2000
WESTERN AUSTRALIA					
Goldfields Gas Pipeline	WA	APA Group (88.2%), BBP (11.8%)	20% expansion to 150 TJ/d		2009
Dampier to Bunbury stage 5A expansion	WA	DUET (60%), BBI (20%), Alcoa (20%)	Capacity increased by 100 TJ/d	660	2008
Dampier to Bunbury stage 4 expansion	WA	DUET (60%), BBI (20%), Alcoa (20%)	200 km	430	2006
Telfer Pipeline (Port Hedland to Telfer Goldmine)	WA	APA Group	443 km	114	2004
Kambalda to Esperance Pipeline	WA	ANZ Infrastructure Services	350 km	45	2004
NORTHERN TERRITORY					
Bonaparte Gas Pipeline	NT	Energy Infrastructure Investments	287 km	170	2008
Wickham Point Pipeline	NT	Energy Infrastructure Investments	13 km	36	2009

PIPELINE	LOCATION	OWNER/PROPONENT	SCALE	COST ($ MILLION)	COMPLETION DATE
UNDER CONSTRUCTION					
SOUTH EAST AUSTRALIA					
Moomba to Sydney Pipeline	NSW	APA Group	Five year 20% capacity expansion	100	From 2008
Eastern Gas Pipeline	Vic–NSW	Jemena	Expansion from 250 TJ/d to 268 TJ/d	41	2010
NORTH EAST AUSTRALIA					
Queensland Gas Pipeline expansion	Qld	Jemena	Expansion from 79 TJ/d to 133 TJ/d	112	2010
WESTERN AUSTRALIA					
Dampier to Bunbury stage 5B expansion	WA	DUET (60%), BBI (20%), Alcoa (20%)	113 TJ/day	690	2010
ANNOUNCED					
NORTH EAST AUSTRALIA					
South West Queensland Pipeline—stage 2	Qld	Epic Energy	Expansion to 220 TJ/d	64	2013
QSN Link—stage 2	Qld–SA and NSW	Epic Energy			
South West Queensland Pipeline—stage 3	Qld	Epic Energy	Expansion to 380 TJ/d	760	Conditional agreement
QSN Link—stage 3	Qld–SA and NSW	Epic Energy			
Queensland Hunter Pipeline (Wallumbilla–Newcastle)	Qld–NSW	Hunter Gas Pipeline	831 km	750–850	2012
Lions Way Pipeline (Casino to Ipswich)	NSW–Qld	Metgasco	145 km	120	2010–11
Gladstone LNG Pipeline (Fairview–Gladstone)	Qld	Santos	432 km		2014
Surat Basin to Gladstone	Qld	Arrow	450 km	500	n/a
WESTERN AUSTRALIA					
Dampier to Bunbury stage 5C expansion	WA	DUET (60%), BBI (20%), Alcoa (20%)	100 TJ/d		2011–12

TJ/d, terajoules per day; BBI, Babcock & Brown Investment.

Note: Projections of future scale, costs and completion dates are indicative.

Sources: EnergyQuest, *Energy Quarterly*, August 2009; ABARE, *Major development projects*, Canberra, April 2009; National Gas Market Bulletin Board (www.gasbb.com.au); corporate websites, reports and media releases.

9.4.5 Effects on competition

Investment over the past decade has led to the development of an interconnected gas pipeline system covering southern and eastern Australia. While gas tends to be purchased from the closest possible source to minimise transport costs, interconnection of the major pipelines provides energy customers with greater choice and enhances the competitive environment for gas supply.

Table 9.4 lists the pipelines and gas basins serving each major Australian market. Gas customers in Sydney, Melbourne, Canberra, Adelaide, Perth and Darwin are now served by multiple transmission pipelines from multiple gas basins. In particular, the construction of new pipelines and the expansion of existing ones have opened the Surat–Bowen, Cooper, Sydney, Gippsland, Otway and Bass basins to increased interbasin competition.

The National Gas Market Bulletin Board, which commenced in July 2008, provides real-time information on the gas market to enhance competition. The AER draws on the bulletin board to report weekly on gas market activity in southern and eastern Australia. The reporting covers gas flows on particular pipelines and gas flows from competing basins to end markets. Figures 9.5–9.8 illustrate recent activity.

Figure 9.5 illustrates the effects of the opening of the QSN Link on gas flows in south west Queensland. Since the commissioning of the QSN Link in January 2009, westerly flows have significantly increased along the South West Queensland Pipeline, feeding into the QSN Link and the Carpentaria Pipeline to Mount Isa. Figure 9.5 shows average gas flows (including flows to southern markets via South Australia) have roughly trebled since the opening of the QSN Link. Average daily flows for the week ending 12 September 2009, for example, were about 111 terajoules higher than average flows in the same period in 2008. Gas flows to the southern states via the QSN Link accounted for about half of this increase.

Figures 9.6–9.8 illustrate recent trends in the delivery of gas from competing basins into New South Wales, Victoria and South Australia since the opening of the bulletin board in July 2008:

- While New South Wales historically relied on Cooper Basin gas shipped on the Moomba to Sydney Pipeline, gas shipped on the Eastern Gas Pipeline from Victoria's Gippsland Basin now supplies a substantial proportion of the state's gas requirements.
- While the Gippsland Basin remains the principal source of gas supply for Victoria, the state also sources some of its requirements from the Otway Basin via the South West Pipeline (an artery of the Victorian Transmission System). Victoria also sources some gas from the northern basins via the New South Wales – Victoria Interconnect Pipeline.
- The Moomba to Adelaide Pipeline and the SEA Gas Pipeline each transport substantial volumes of gas for the South Australian gas market. The Moomba to Adelaide Pipeline transports gas from Queensland's Surat–Bowen Basin via the QSN Link, and South Australia's Cooper Basin. The SEA Gas Pipeline delivers gas from Victoria's Otway Basin.

While Santos, Origin Energy and BHP Billiton have production interests in several gas basins, transmission pipeline interconnection has also provided new markets for smaller producers. Interconnection may benefit the wider energy sector too. In particular, it may enhance competition in electricity markets by creating opportunities for further investment in gas fired generators.

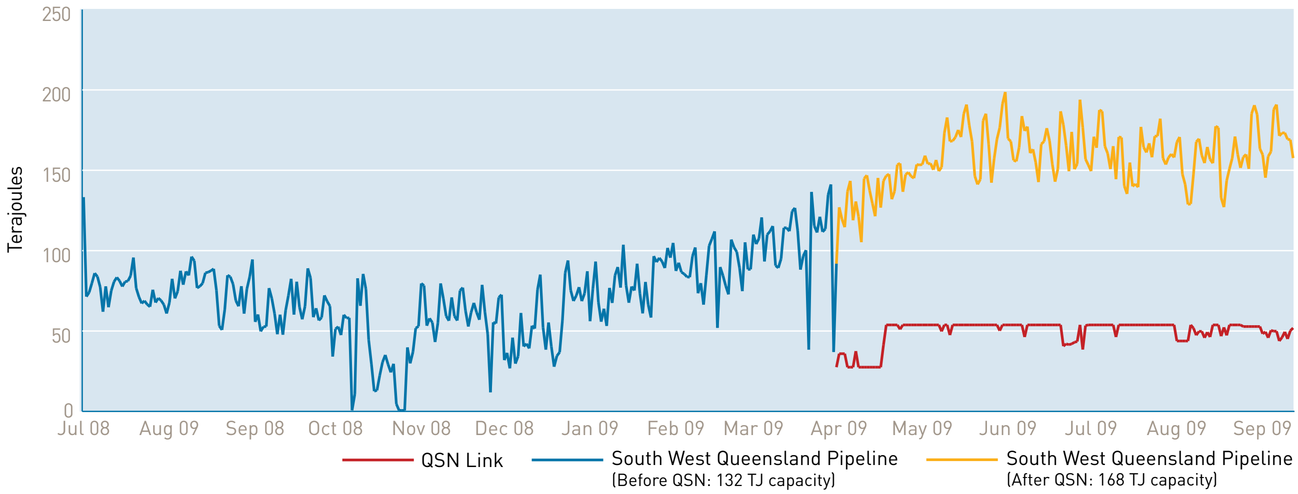
The extent to which new investment delivers competition benefits to customers depends on a range of factors, including the availability of natural gas and pipeline access from alternative sources. In particular, capacity constraints limit access on some pipelines. The Eastern Gas, SEA Gas and Roma to Brisbane pipelines, for example, have tended to operate at or near capacity in recent years. Access seekers must decide whether to try to negotiate a capacity expansion. For a covered pipeline, the regulator (or, in Western Australia, a separate arbitrator) may be asked to arbitrate a dispute over capacity expansions.

Table 9.4 **Pipeline links between major gas basins and markets**

MARKET / PIPELINES	GAS BASIN	PRODUCERS
SYDNEY AND CANBERRA		
Moomba to Sydney Pipeline (APA Group)	Cooper, Sydney	Santos, Beach Petroleum, Origin Energy, AGL Energy, Sydney Gas
Eastern Gas Pipeline (Singapore Power International), NSW—Vic Interconnect (APA Group)	Gippsland, Otway, Bass	BHP Billiton, ExxonMobil, Origin Energy, Santos AWE, Beach Petroleum
South West Queensland Pipeline/ QSN Link (Epic Energy)	Surat–Bowen	Origin Energy, Santos, Arrow Energy, BG Group, AGL Energy, ConocoPhillips, Petronas
MELBOURNE		
NSW–Vic Interconnect (APA Group)	Cooper (via MSP), Sydney	Santos, Beach Petroleum, Origin Energy, AGL Energy, Sydney Gas
Victorian Transmission System (APA Group)	Gippsland, Bass, Otway	BHP Billiton, ExxonMobil, Origin Energy, Santos AWE, Beach Petroleum
TASMANIA		
Tasmanian Gas Pipeline (Babcock & Brown Infrastructure)	Cooper (via MSP and NSW—Vic Interconnect), Gippsland, Otway, Bass	Santos, Beach Petroleum, Origin Energy
BRISBANE		
Roma to Brisbane Pipeline (APA Group)	Surat–Bowen	Mosaic, Origin Energy, Santos, BG Group, Arrow Energy, Mitsui, Molopo
ADELAIDE		
Moomba to Adelaide Pipeline (Epic Energy)	Cooper	Santos, Beach Petroleum, Origin Energy
SEA Gas Pipeline (APA Group, International Power, Retail Employees Superannuation Trust)	Otway and Gippsland	BHP Billiton, ExxonMobil, Origin Energy, Santos AWE, Beach Petroleum
South West Queensland Pipeline/ QSN Link (Epic Energy)	Surat–Bowen	Origin Energy, Santos, Arrow Energy, BG Group, AGL Energy, ConocoPhillips, Petronas
DARWIN		
Amadeus Basin to Darwin (96% APA Group)	Amadeus	Magellan, Santos
Bonaparte Pipeline (Energy Infrastructure Investments)	Bonaparte	ENI
PERTH		
Dampier to Bunbury Natural Gas Pipeline (DUET, Alcoa, Babcock & Brown Infrastructure)	Carnarvon, Perth	Apache Energy, BHP Billiton, BP, Chevron, ExxonMobil, Inpex, Kufpec, Santos, Shell, Tap Oil, Woodside Petroleum, ARC Energy, Origin Energy
Parmelia Pipeline (APA Group)	Perth	ARC Energy, Origin Energy

MSP, Moomba to Sydney Pipeline.

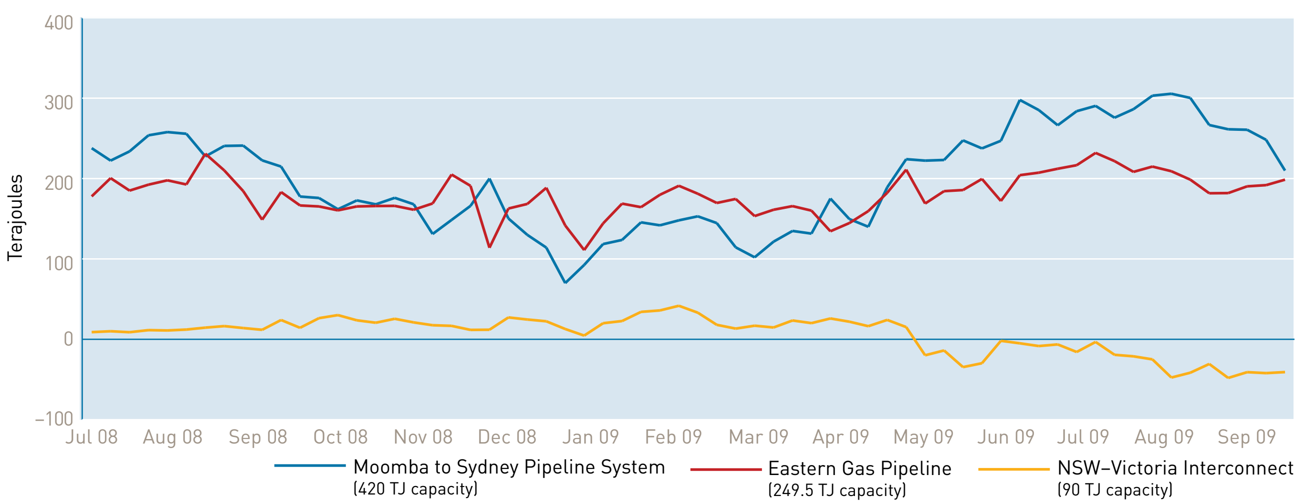
Figure 9.5
Gas flows on the South West Queensland Pipeline



Note: While the QSN Link was commissioned in January 2009, reporting of gas flows began on 31 March 2009.

Source: National Gas Market Bulletin Board, www.gasbb.com.au/AER.

Figure 9.6
Gas flows into New South Wales



Notes: Negative flows on the New South Wales — Victoria Interconnect represent flows out of New South Wales into Victoria.

Figure 9.7
Gas flows into Victoria

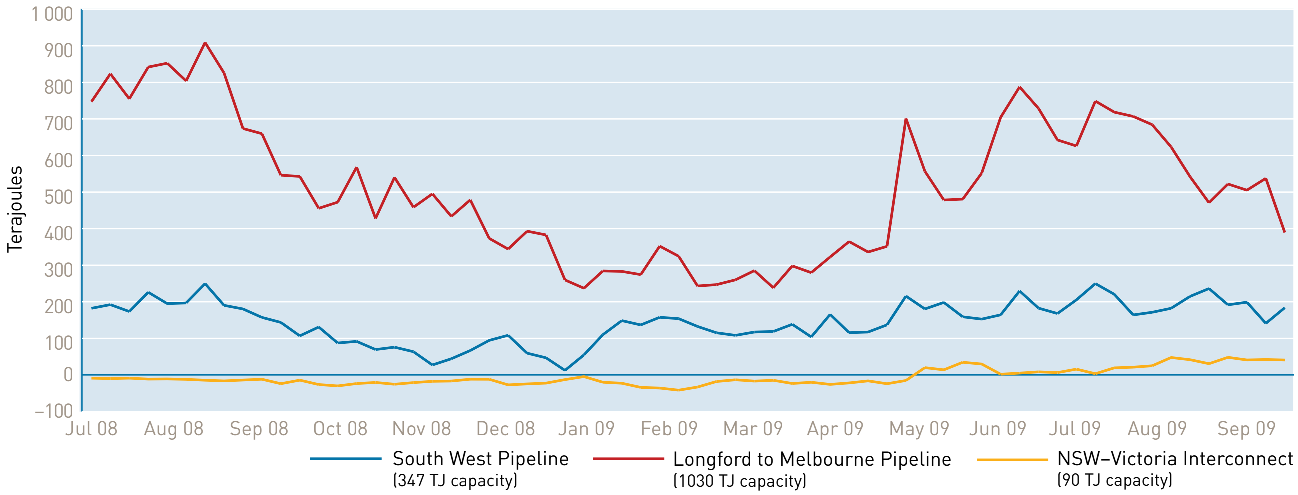
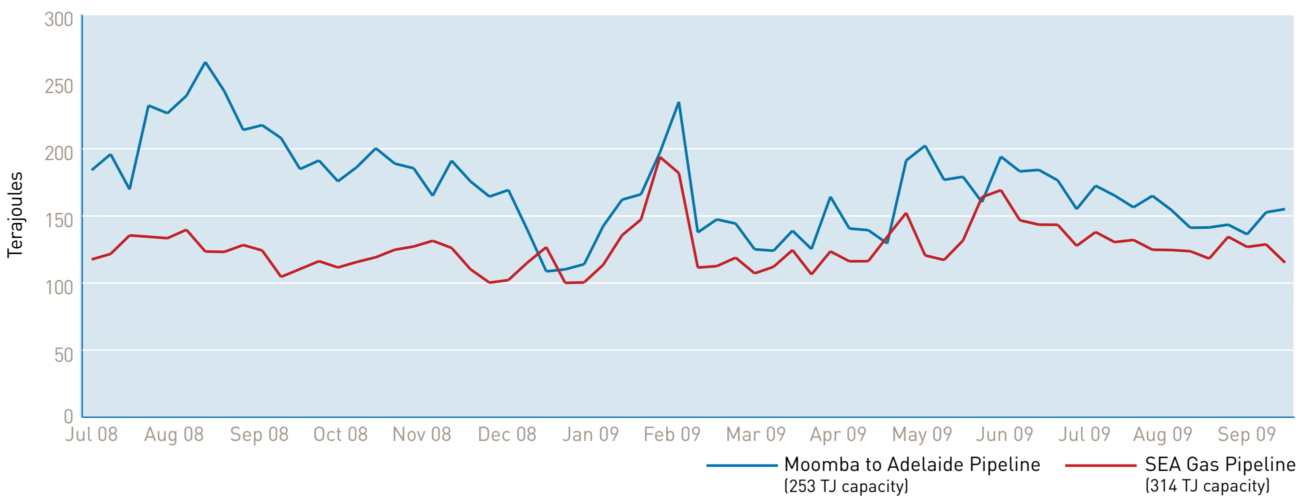


Figure 9.8
Gas flows into South Australia



Source (figures 9.6–9.8): Natural Gas Market Bulletin Board (www.gasbb.com.au)/AER.

9.5 Pipeline tariffs

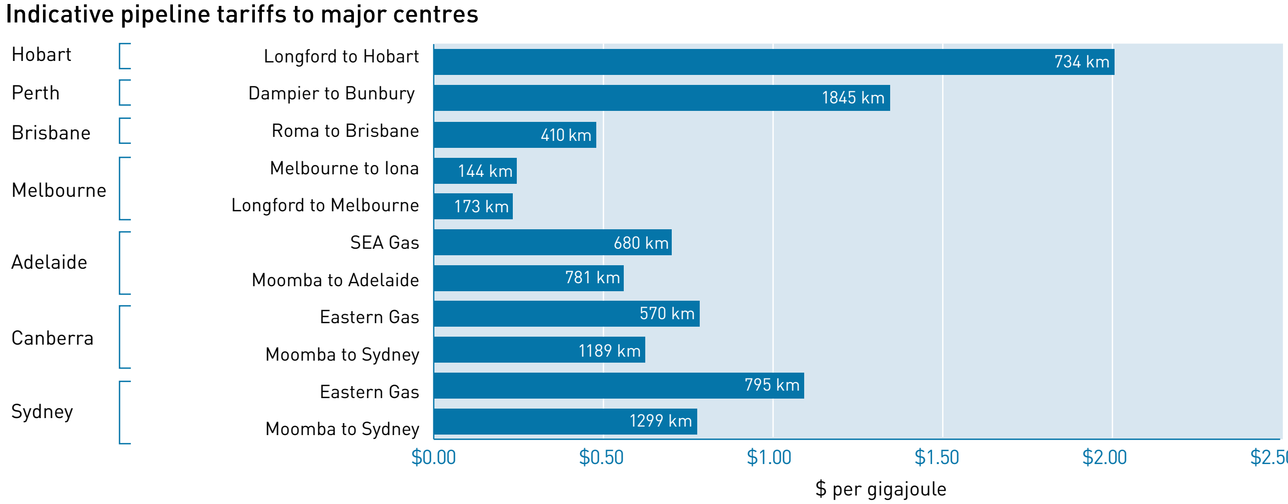
The Gas Law requires providers of covered pipelines to publish reference tariffs (prices) and other conditions of access. Service providers must maintain this information on their website, either within their approved access arrangement or separately. They are not required to disclose tariffs for non-covered pipelines, or negotiated tariffs (for covered pipelines) agreed outside the reference tariffs. Some operators publish these tariffs on a website or make them available on request to access seekers.

Figure 9.9 sets out EnergyQuest estimates of indicative pipeline tariffs on selected routes between gas basins and Australian capital cities. The tariffs reflect factors such as differences in transportation distances; underlying capital costs; the age and extent of depreciation on the pipeline; technological and geographic differences; and the availability of spare pipeline capacity. In general, it is cheaper to transport gas into Sydney, Canberra and Adelaide from the Cooper Basin than from the Victorian coastal basins.

In practice, pipeline tariffs may vary considerably from the indicative tariffs in figure 9.9. An access seeker can try to negotiate discounts against published rates. Some tariffs may be higher than those in figure 9.9, especially if a pipeline is capacity constrained and requires an expansion to make access possible. Tariffs for interruptible services[21] are typically 30 per cent higher than those for firm transportation charges, but are paid on the actual quantities shipped rather on reserved capacity.[22]

The key consideration for customers is the cost of delivered gas—the bundled cost of gas and transportation services—from alternative sources. The lead essay of the *State of the energy market 2008* report provided ACIL Tasman estimates of the composition of delivered gas prices in mainland state capital cities.[23] Retail prices ranged from around $15.50 per gigajoule in Melbourne to almost $28 per gigajoule in Brisbane. Transportation through the high pressure transmission system is the smallest contributor to delivered costs for residential consumers. Transmission charges range from around 2 per cent

Figure 9.9
Indicative pipeline tariffs to major centres



Note: Distances are indicative.

Source: EnergyQuest, *Energy Quarterly*, August 2009.

21 Interruptible services are provided intermittently, depending on available pipeline capacity.

22 NERA, *The gas supply chain in eastern Australia*, Sydney, June 2007, pp. 42 and 52. Chapter 8 of this report discusses backhaul arrangements.

23 The report is available on the AER website, www.aer.gov.au.

of delivered gas prices in Adelaide and Melbourne to 7 per cent in Perth. For larger industrial customers, this proportion rises steadily with scale because the fixed costs associated with downstream services are spread across larger gas supply volumes.

9.6 Performance indicators

Performance data for the gas transmission sector are limited. Historically, performance reports have not been published for covered pipelines, although the Gas Law enables the AER to publish such reports in the future. Regulatory decisions on access arrangements include some historical data, as well as forward projections.

The financial data available on transmission pipelines comprise mainly financial forecasts in regulatory determinations for a small number of covered pipelines. The *State of the energy market 2008* report reproduces some of the limited available data.[24] There has been little historical reporting of service quality outcomes.

As noted, the owners of non-covered pipelines are not required to report publicly on historical performance or projected outcomes. The Gas Market Bulletin Board is increasing public information about transmission pipelines, including capacity and supply information. It covers most transmission pipelines in southern and eastern Australia, including non-covered pipelines.[25]

24 AER, *State of the energy market 2008*, Melbourne, 2008, section 9.6.
25 Section 8.7.2 of this report provides further information on the bulletin board.

10 GAS DISTRIBUTION

Natural gas distribution networks take gas from transmission pipelines and reticulate it into residential homes, offices, hospitals and businesses. Their main customers are energy retailers, which aggregate loads for sale to customers. For small gas customers, distribution charges for metering and transport often represent the most significant component—up to 60 per cent—of retail gas prices.

10 GAS DISTRIBUTION

This chapter considers:

> Australia's gas distribution sector
> the structure of the sector, including industry participants and ownership changes over time
> the economic regulation of distribution networks
> new investment in distribution networks
> financial indicators and the service performance of the distribution sector.

10.1 Role of distribution networks

A distribution network typically consists of high, medium and low pressure pipelines. The high and medium pressure mains provide a 'backbone' that services areas of high demand and transports gas between population concentrations within a distribution area. The low pressure pipes lead off the high pressure mains to end customers.

Gate stations (city gates) link transmission pipelines with distribution networks. The stations measure the natural gas entering a distribution system, for billing and gas balancing purposes. They also adjust the pressure of the gas before it enters the distribution network. Distributors can further adjust gas pressure at regulating stations in the network to ensure gas is delivered at a suitable pressure to operate customer equipment and appliances.

10.2 Australia's distribution networks

The total length of Australia's gas distribution networks expanded from around 67 000 kilometres in 1997 to over 82 000 kilometres in 2009. The networks deliver over 370 petajoules of gas a year and have a combined valuation of almost $8 billion. Investment to augment and expand the networks is forecast at around $2 billion in the current access arrangement periods (typically five years). Table 10.1 provides summary details of the major networks.

Table 10.1 Australian natural gas distribution networks

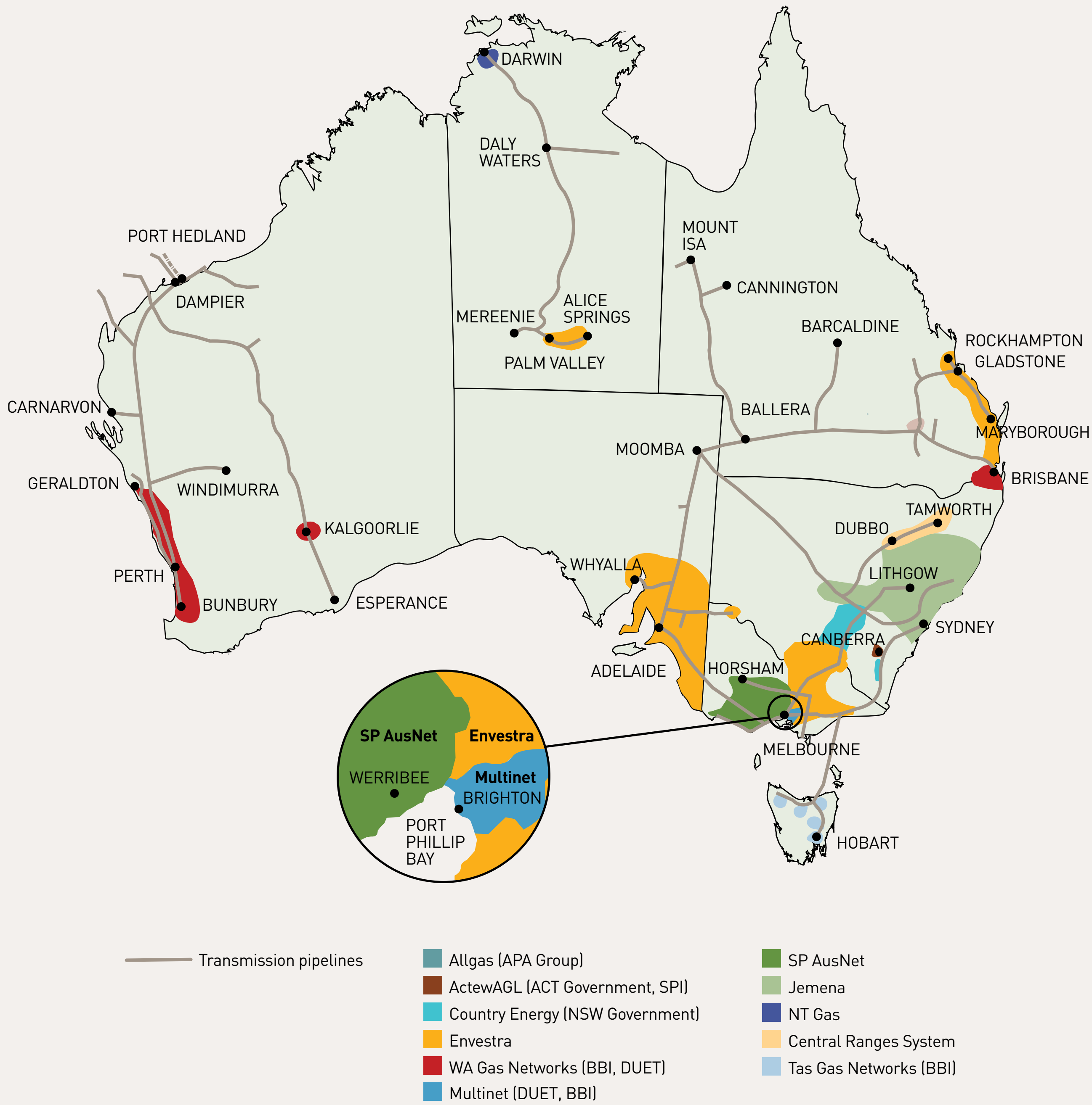
DISTRIBUTION NETWORK	LOCATION	LENGTH OF MAINS (KM)	OPENING CAPITAL BASE (2008 $ MILLION)[1]	INVESTMENT—CURRENT ACCESS ARRANGEMENT (2008 $ MILLION)[2]	CURRENT REGULATORY PERIOD	OWNER
QUEENSLAND						
APT Allgas	South of the Brisbane River	2 605	362	141	1 July 2006 – 30 June 2011	APA Group
Envestra	Brisbane, Gladstone and Rockhampton	2 489	261	104	1 July 2006 – 30 June 2011	Envestra (APA Group 30.6%, Cheung Kong Infrastructure 18.5%)
NEW SOUTH WALES AND THE ACT						
Jemena Gas Networks (NSW)	Sydney, Newcastle/ Central Coast, Wollongong and parts of country NSW	23 800	2 300	542	1 July 2005 – 30 June 2010	Jemena (Singapore Power International)
ActewAGL	ACT, Palerang (Bungendore) and Queanbeyan	3 604	266	66	1 July 2004 – 30 June 2010	ACTEW Corporation (ACT Govt) 50%; Jemena (Singapore Power International) 50%
Wagga Wagga	Wagga Wagga and surrounding areas	622	49	8	1 July 2005 – 30 June 2010	Country Energy (NSW Govt)
Central Ranges System	Tamworth	180	n/a	n/a	2006–19	APA Group
VICTORIA						
SP AusNet	Western Victoria	9 284	955	342	1 Jan 2008 – 31 Dec 2012	SP AusNet (listed company: Singapore Power International 51%)
Multinet	Melbourne's eastern and south eastern suburbs	9 585	888	232	1 Jan 2008 – 31 Dec 2012	DUET Group 79.9%, BBI 20.1%
Envestra	Melbourne, north eastern and central Victoria, and Albury–Wodonga region	9 603	859	411	1 Jan 2008 – 31 Dec 2012	Envestra (APA Group 30.6%, Cheung Kong Infrastructure 18.5%)
SOUTH AUSTRALIA						
Envestra	Adelaide and surrounds	7 477	942	213	1 July 2006 – 30 June 2011	Envestra (APA Group 30.6%, Cheung Kong Infrastructure 18.5%)
TASMANIA						
Tas Gas Networks	Hobart, Launceston and other towns	730	112[1]	Not regulated	Not regulated	Tas Gas (BBI)
WESTERN AUSTRALIA						
WA Gas Networks	Mid-west and south western regions	12 176	749	163	1 Jan 2005 – 31 Dec 2009	BBI 74.1%, DUET Group 25.9% Operated by WestNet Energy (owned by BBI)
National totals[3]		82 155	7 743	2 222		

BBI, Babcock & Brown Infrastructure. n/a, not available.

1. For Tasmania, the opening capital base value is an estimated construction cost. For other networks, the opening capital base is the initial capital base, adjusted for additions and deletions, as reset at the beginning of the current access arrangement period. All data are converted to June 2008 dollars.
2. Investment data are forecasts for the current access arrangement period, adjusted to June 2008 dollars.
3. National totals exclude the Northern Territory.

Sources: Access arrangements for covered pipelines; company websites.

Figure 10.1
Gas distribution networks in Australia



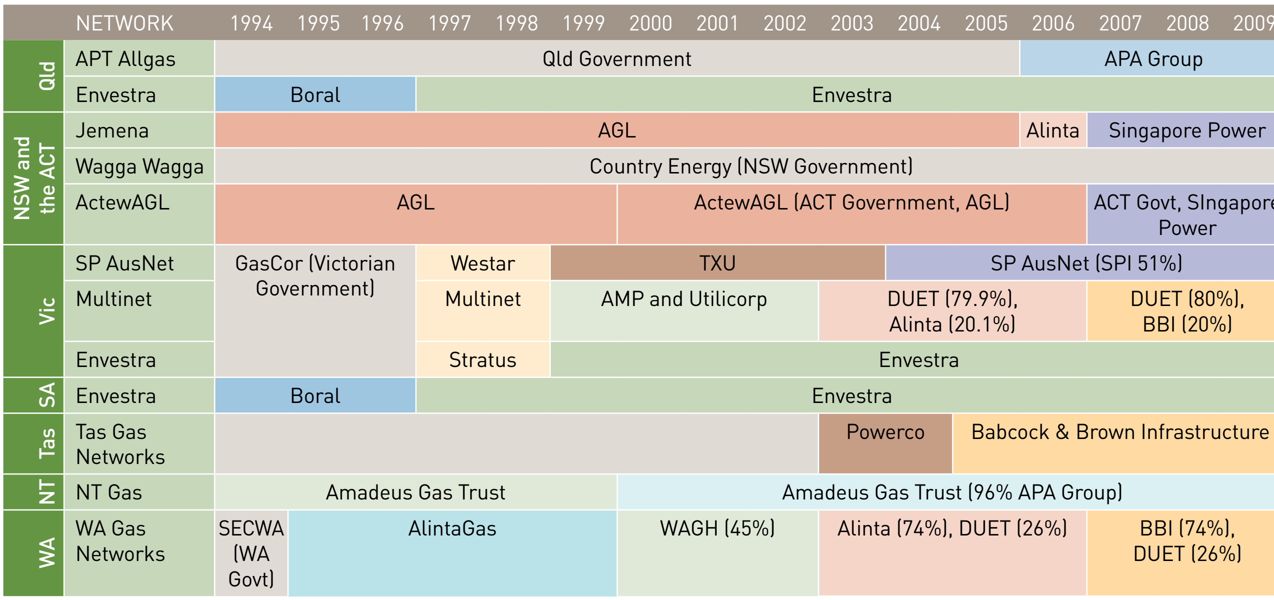
Notes:

Locations of the distribution systems are indicative only.

Some corporate names have been abbreviated.

Figure 10.2

Gas distribution network ownership



BBI, Babcock & Brown Infrastructure; SECWA, State Energy Commission of Western Australia; WAGH, WA Gas Holdings.

Note: Some corporate names have been abbreviated or shortened. Some minor networks are not shown.

Figure 10.1 shows the locations of the major networks. New networks have been rolled out in north western New South Wales (Central Ranges) and Tasmania following construction of transmission pipelines in these regions. Natural gas is now reticulated to most Australian capital cities, major regional areas and towns.

10.3 Ownership of distribution networks

The major gas distribution networks in Australia are privately owned. South Australia, Victoria, Western Australia and Queensland privatised their state owned networks in 1993, 1997, 2000 and 2006 respectively. The principal New South Wales network and the new Tasmanian network have always been in private hands.[1] AGL developed the Australian Capital Territory (ACT) network, but in 2000 formed a joint venture with the government owned Actew Corporation.

Structural reform and capital market drivers have led to specialist network businesses acquiring most gas distribution assets. Figure 10.2 shows key ownership changes since 1994.

By 2008 ownership consolidation had reduced the number of principal players to four:

> *Singapore Power International* owns the principal New South Wales gas distribution network (Jemena Gas Networks). It has a 51 per cent share in the Victorian network (SP AusNet) and a 50 per cent share of the ACT network (ActewAGL). In August 2008 Singapore Power International rebranded its directly owned distribution entities as Jemena.

> *Envestra*, a public company in which APA Group (31 per cent) and Cheung Kong Infrastructure (19 per cent) have shareholdings, owns networks in Victoria, South Australia, Queensland and the Northern Territory.

> *Babcock & Brown Infrastructure* owns the Tasmanian distribution network and is the majority owner of the WA Gas Networks.

> *APA Group* owns the APT Allgas networks in Queensland and has a 31 per cent stake in Envestra.

1 There are remnants of state owned networks in rural New South Wales (the Wagga Wagga network owned by Country Energy) and Queensland (the Roma network owned by the Roma Regional Council and the Dalby network owned by the Dalby Regional Council).

In addition, DUET Group is the majority owner of Victoria's Multinet network and a minority owner of WA Gas Networks.[2] It contracts out the operation of these networks.

There are significant ownership links between gas distribution and other energy networks. In particular, Singapore Power International, Babcock & Brown Infrastructure and APA Group own and/or operate gas transmission pipelines. In addition, Singapore Power International, APA Group, Cheung Kong Infrastructure and DUET Group all have ownership interests—in some cases, substantial interests—in the electricity network sector (see chapters 5, 6 and 9).

10.4 Regulation of distribution networks

Gas distribution networks are capital intensive and incur declining marginal costs as output increases. This gives rise to a natural monopoly industry structure. In Australia, most networks are regulated to ensure energy retailers and other parties can transport gas on reasonable terms and conditions.

The National Gas Law (Gas Law) and National Gas Rules (Gas Rules) provide the overarching regulatory framework for the gas distribution sector. The Gas Law and Gas Rules commenced on 1 July 2008 in all states and territories except Western Australia, which expects to implement the pipeline access provisions in the second half of 2009. These instruments replace the Gas Pipelines Access Law and the National Gas Code, which had provided the regulatory framework from 1997.

The regulation of distribution networks in southern and eastern Australia transferred from state and territory agencies to the Australian Energy Regulator (AER) on 1 July 2008. The AER is working closely with jurisdictional regulators and network businesses to maintain regulatory certainty in the transition from state based to national regulation. In Western Australia, the Economic Regulation Authority continues to regulate gas distribution services.

10.4.1 Which networks are regulated?

The Gas Law includes a coverage mechanism to determine which pipelines are subject to economic regulation. At July 2009 the Gas Law covered 12 distribution networks, including all major networks in New South Wales, Victoria, Queensland, Western Australia, South Australia and the ACT. The recently constructed Tasmanian distribution network is the only major unregulated network. In addition, a number of small regional networks are not covered.[3]

10.4.2 Regulatory framework

In Australia, the providers of gas distribution services negotiate contracts to sell pipeline services to customers such as energy retailers. The contracts, which set the terms and conditions of network access, are negotiated on commercial terms that may differ from those that may be set through regulatory processes.

There are different forms of economic regulation for covered pipelines, based on criteria set out in the Gas Law.[4] Currently, most Australia distribution networks are subject to full regulation, which requires the service provider to submit an access arrangement to the regulator for approval.[5] An access arrangement sets out terms and conditions for third parties to use a pipeline. It must specify at least one reference service that most customers commonly seek, and a reference tariff for that service.

2 DUET Group comprises a number of trusts, for which Macquarie Bank and AMP Capital Holdings own the responsible entities.

3 A party may seek a change in the coverage status of a pipeline by applying to the coverage body, which is the National Competition Council. At present, the non-covered networks include the South West Slopes and Temora extensions of the NSW Gas Network; the Dalby and Roma town systems in Queensland; the Alice Springs network in the Northern Territory; and the Mildura system in Victoria.

4 The AER published an *Access arrangement guideline* in March 2009, which sets out the forms of regulation (see part 2). The guideline is available on the AER website at www.aer.gov.au.

5 The service provider may be the controller, owner or operator of the whole pipeline or any part of the pipeline.

A reference tariff may apply to one or more of the reference services offered to different groups of customers, and might cover capacity reservation (managed capacity services), volume (throughput services), peak, off-peak and metering (data) services. A network may also provide non-reference services, for which the AER does not approve the terms and conditions of access.

An access arrangement must also set out non-price terms and conditions, such as capacity expansion policies, queuing requirements and gas quality specifications.[6] More generally, an access arrangement must comply with the provisions of the Gas Law, including pricing principles, ring-fencing requirements and provisions for associate contracts. In the event of a dispute, an access seeker may request the regulator to arbitrate and enforce the terms and conditions of the access arrangement.[7] The AER has published a guideline on dispute resolution under the Gas Law.[8]

In some instances, a distribution pipeline may be subject to light regulation, in which the service provider is obliged to publish the terms and conditions of access on its website. While there are currently no light regulation distribution networks, the Gas Law establishes a process that may allow a distribution pipeline to convert to this form of regulation. However, light regulation may not apply to the Victorian and South Australian distribution pipelines listed in table 10.1.

10.4.3 Regulatory process

For a pipeline subject to full regulation, the Gas Law requires the network provider to submit an initial access arrangement to the regulator and revise it periodically. The revisions generally occur once every five years as scheduled reviews, but can occur more frequently—for example, if a trigger event compels an earlier review or the service provider seeks a variation to the access arrangement.

The Gas Rules prescribe the process and timeframe for an access arrangement review.[9] A provider may consult with the AER to help develop a complete and well framed proposal. The AER recommends that this consultation process would ideally commence about six months before the scheduled submission date. Once a provider has submitted its access arrangement, the AER has six months to decide whether to approve the proposal. The review process allows time for stakeholder consultation and the engagement of specialist consultants. The consultation and information gathering processes 'stop the clock' and do not count towards the six month decision making time. This means the review process generally takes about nine to 12 months to complete. The decision making timeframe can be extended a further two months, with an absolute time limit of 13 months for a decision to be made.[10]

An AER decision on an access arrangements is subject to merits review by the Australian Competition Tribunal and judicial review by the Federal Court of Australia.

6 For further information on non-price matters, see AER, *Access arrangement guideline, final,* Melbourne, March 2009, at s.5.4.1.

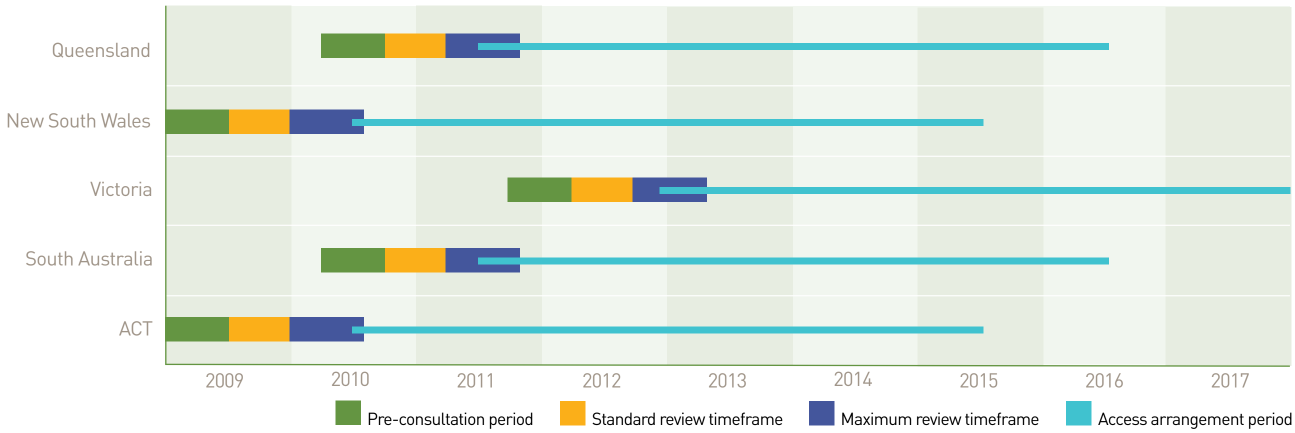
7 In Western Australia, a separate arbitrator hears access disputes.

8 AER, *Guideline for the resolution of distribution and transmission pipeline access disputes under the National Gas Law and National Gas Rules, final,* Melbourne, November 2008.

9 The AER published an *Access arrangement guideline* in March 2009, which sets out these processes. The guideline is available on the AER website at www.aer.gov.au.

10 The regulatory process in Western Australia is undertaken by the Economic Regulation Authority.

Figure 10.3
Indicative decision making timelines



Note: The timeframes are indicative. The standard review period begins when a network business submits an access arrangement proposal to the AER by a date specified in the previous access arrangement. The timeframes may vary if the AER grants a time extension for the submission of a proposal. An access arrangement period is typically five years, but a provider may apply for a different duration.

Figure 10.3 shows indicative timeframes for the networks. The AER's first access arrangement review in gas distribution will set prices and other access terms and conditions from July 2010 for covered networks in New South Wales and the ACT. ActewAGL and Country Energy submitted their access arrangement revisions on 30 June 2009 and 1 July 2009 respectively. Jemena submitted its access arrangement revisions on 25 August 2009.

The AER will begin its next scheduled reviews—for the South Australian and Queensland networks—in the fourth quarter of 2010.[11]

10.4.4 Regulatory approach

The Gas Rules require the use of a building block approach to determine total revenues and derive tariffs. A number of alternatives are permitted for applying this approach (see section 9.3.4 of this report). Total revenue must be sufficient to allow a business to recover efficient costs, including depreciation and an appropriate return on capital. The Gas Rules also allow for income adjustments from incentive mechanisms that reward efficient operating practices. Once total revenue is determined, revenue is allocated to services provided by the distribution pipeline to establish reference tariffs. The tariffs are typically adjusted annually for inflation and other approved factors.[12]

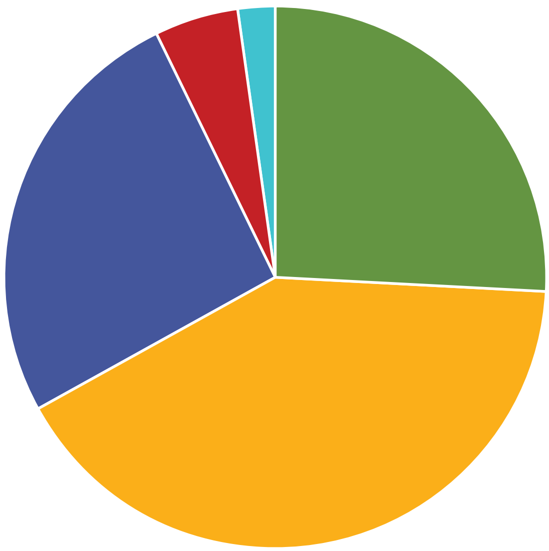
In approving a reference tariff, the AER must have regard to the costs of a prudent and efficient service provider of a pipeline service. In doing so, it will consider the circumstances in which a pipeline operates and draw on expert assessments, submissions from interested parties, benchmarking, the operation of efficiency mechanisms and key performance indicator information.

Figure 10.4 shows the revenue components of SP AusNet's current access arrangement in Victoria. It illustrates the relative importance of the building block components in a typical reference tariff determination. Depreciation and return on capital account for around two thirds of the revenue. Operating and maintenance costs, tax and incentive mechanism payments account for the balance.

11 APT Allgas is due to lodge access arrangement revisions for its Queensland distribution network on 30 September 2010. Envestra is due to lodge revisions for its Queensland and South Australian networks on 1 October 2010.

12 For further information on reference tariffs, see AER, *Access arrangement guideline, final,* Melbourne, March 2009, at s.5.4.2.

Figure 10.4
Revenue components for Victoria's SP AusNet gas network, 2008–12



Source: ESC, *Gas access arrangement review 2008–2012: further final decision*, Melbourne, 2008, p. 37.

10.5 Investment in distribution networks

Investment in gas distribution typically involves capital works to upgrade and expand the capacity of existing networks and extend the networks into new residential and commercial developments, regional centres and towns. While most major centres already have a distribution network in place, new networks have recently been constructed—for example, the Central Ranges (New South Wales) and Tasmanian networks.

Stay-in-business investment tends to be a relatively stable proportion of the capital base for most networks. However, investment that is program specific—such as meter replacement and major network refurbishment—may have 'lumpy' investment profiles. In addition, a network's configuration may include high pressure or trunk pipelines that require significant upfront capital investment and additions over time, giving rise to 'lumpy' investment characteristics similar to those of transmission pipelines.

The cost of distribution investment depends on a range of factors, including:

> the distance of new infrastructure from access points on gas transmission lines or gas distribution mains

> the density of housing and the presence of other industrial and commercial customers in the area.

Figure 10.5 shows the opening capital bases and forecast investment over the current access arrangement period (typically five years) for the major networks. Figure 10.6 shows annual investment (in June 2008 dollars) in each network, based on actual data where available and forecast data for other years. The forecast data relate to proposed investment that the regulator has approved as efficient. The data are smoothed over the forecast period to remove the significant volatility often evident in annual forecast data. Figure 10.6 excludes Tasmanian's unregulated network, for which data are not available.

Investment in gas distribution networks has grown steadily in recent years:

> Investment was forecast at around $440 million in 2008–09, and grew on average by around 8 per cent annually over the preceding five years.

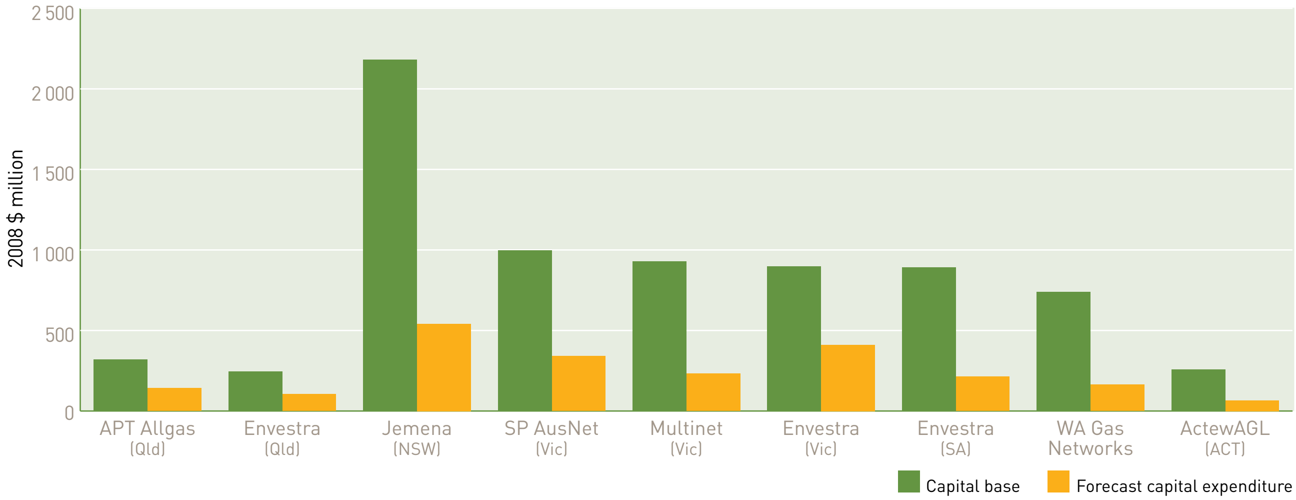
> Over the longer term, real investment of around $2 billion is forecast during the current access arrangement periods for the major networks. This represents both substantial real investment in new infrastructure as well as rising resource costs in the construction sector.

> Investment in current access arrangements is running at around 25 per cent of the underlying capital base for most networks, but around 35 per cent for SP AusNet (Victoria) and 40–50 per cent for Envestra (Victoria) and the Queensland networks.

> The combined Victorian networks attract significantly higher investment than does New South Wales, partly reflecting the penetration of natural gas as a major heating source in Victoria. More generally, different outcomes across jurisdictions reflect a range of variables, including development activity, incentives or policies that encourage gas supply, market conditions, and investment drivers such as the scale and age of the networks.

Figure 10.5

Gas distribution capital and investment—current regulatory period



Notes:

The valuation for each pipeline is the capital base published in a regulator approved access arrangement.

Investment data represent forecast capital expenditure over the current access arrangement regulatory period (see table 10.1).

All estimates are converted to June 2008 dollars.

Sources: Access arrangements approved by the ESC (Victoria), IPART (New South Wales), the QCA (Queensland), ESCOSA (South Australia), the ERA (Western Australia) and the ICRC (ACT).

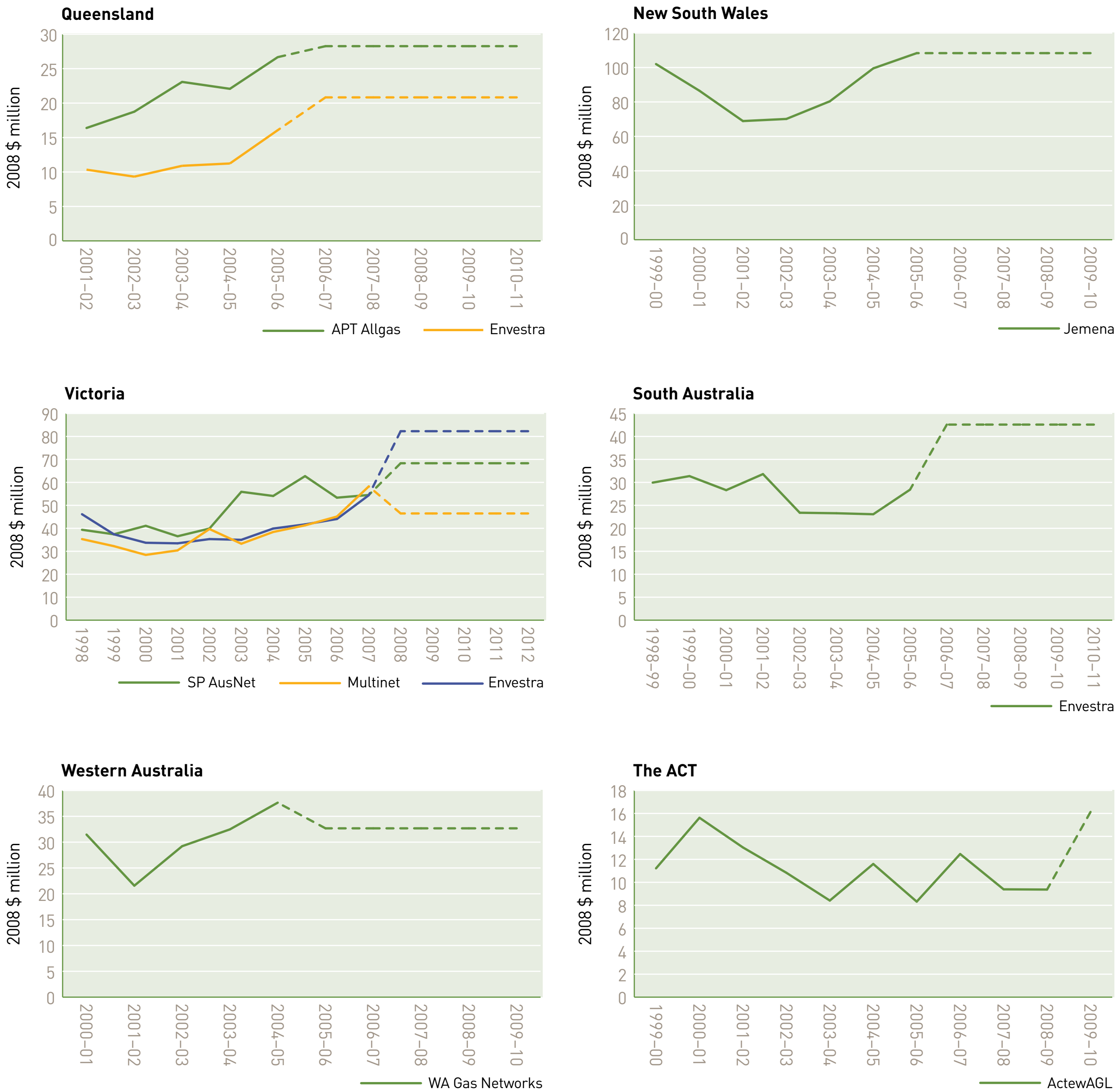
- Investment is forecast to rise strongly in the next few years in Queensland, South Australia and Victoria. Current access arrangement decisions for these jurisdictions reflect a significant step-increase in forecast investment.
- Looking forward, the introduction of carbon emission reduction policies may further accelerate the development of natural gas as an energy source, and influence investment.
- The investment data mostly reflect the incremental expansion of existing networks—for example, Envestra began a $3.7 million project in 2005 to upgrade and extend its Queensland network. The construction of new transmission pipelines also provides opportunities to develop new distribution networks—for example, the Tasmanian distribution network has been rolled out in major cities and towns following the construction of a transmission pipeline from Victoria to Tasmania.

10.6 Operating and maintenance costs

Financial performance reporting for gas networks has generally been less comprehensive than for electricity networks. Only Victoria and South Australia have tended to publish regular financial performance reports on the networks. The reporting arrangements may undergo changes with the shift to national regulation.

Regulatory decisions on access arrangements consider forecasts of a range of financial indicators, including revenues, operating and maintenance costs and returns on capital. Figure 10.7 compares forecast operating and maintenance expenditure for the networks on a per kilometre basis and on a per customer basis for 2008–09. The chart indicates that most networks have expenses ranging from about $4000 to $8000 per kilometre of network line length, or $70–170 per customer. Differences may arise for a number of reasons, including the age and condition of the networks and geographic factors.

Figure 10.6
Gas distribution network investment



Notes:

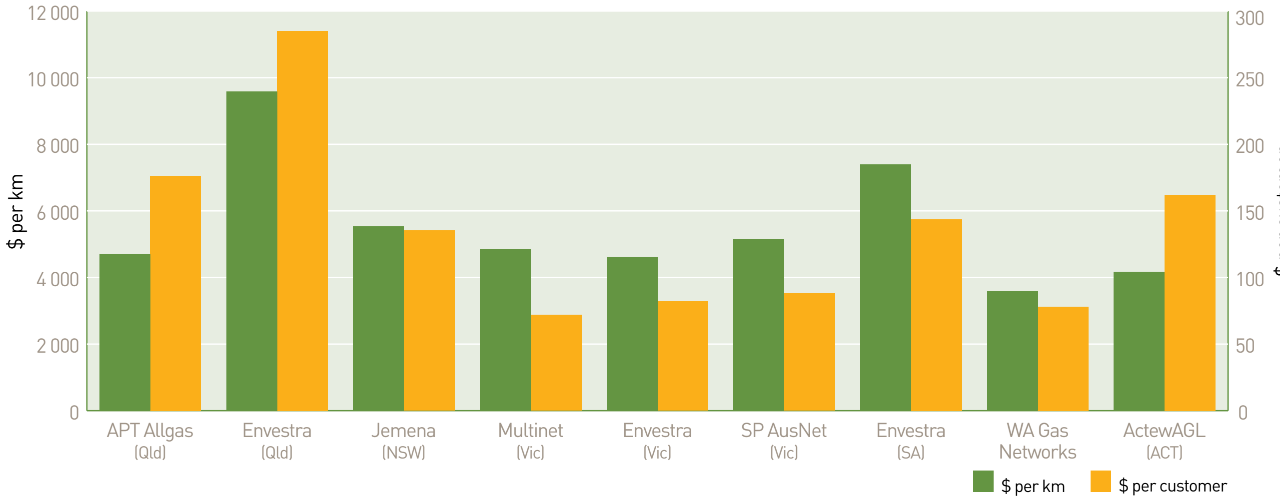
Actual investment outcomes (unbroken lines) used where available. Broken lines are forecast data from approved access arrangements, averaged over the forecast period.

All data converted to June 2008 dollars.

Sources: Access arrangements and network performance reports published by the ESC (Victoria), IPART (New South Wales), the QCA (Queensland), ESCOSA (South Australia), the ERA (Western Australia) and the ICRC (ACT).

Figure 10.7

Operating and maintenance expenditure per kilometre of pipeline and per customer—gas distribution networks, 2008–09



Notes:

Forecast data, converted to 2008 dollars.

Victorian data are for the 2008 calendar year.

Sources: Access arrangements approved by the ESC (Victoria), IPART (New South Wales), the QCA (Queensland), ESCOSA (South Australia), the ERA (Western Australia) and the ICRC (ACT).

Network-specific characteristics mean benchmarking or comparison across different networks has limitations. Comparisons on a per kilometre basis, for example, will be affected by the density of customers and the length of a pipeline network. Conversely, metrics based on customer numbers will vary between networks with large and small customer bases. There are generally very different metrics between networks in rural and city locations.

10.7 Quality of service

Quality of service monitoring for gas distribution services typically relates to:

> the reliability of the gas supply (the provision of a continuous gas supply to customers)
> network integrity (gas leaks, the effectiveness of operational and maintenance activities)
> customer service (responsiveness to issues such as complaints and reported gas leaks).

While the Steering Committee on National Regulatory Reporting Requirements[13] established national reporting indicators on service quality for electricity distribution and energy retailing, no equivalent indicators were developed for gas distribution. Instead, jurisdictions have applied locally determined service standards and reporting arrangements. Some technical and service standards are connected with jurisdictional licensing and safety requirements.

In general, the monitoring and reporting of service quality have been less comprehensive in the natural gas sector than for electricity. The disparity reflects:

> different approaches to reporting across jurisdictions
> a lesser reliance on gas than electricity as an energy source for most customers
> technical characteristics inherent to gas distribution.

13 The Steering Committee on National Regulatory Reporting Requirements is a working group established by the Utility Regulators Forum.

Most jurisdictions publish (or have published) annual service performance reports on gas distribution networks. The reports reflect the dual roles of some jurisdictional agencies as technical and (until 2008) economic regulators. In New South Wales, the Department of Water and Energy publishes the data; in South Australia, Western Australia, Tasmania and the ACT, jurisdictional regulators report on this area. Jurisdictional reporting arrangements may evolve over time with the shift to national regulation. The Queensland Competition Authority ceased performance reporting on gas distribution in 2007. Victoria's Essential Services Commission ceased performance reporting in this area in 2008.

The data in this section are provided for information purposes, and not for making performance comparisons across the networks. As noted, performance monitoring in gas distribution is less evolved than for electricity, and the absence of a uniform national reporting framework can lead to fundamental differences in definitions, measurement and auditing systems. Differences in network age, size, design and historical investment can also have significant effects on measured performance.

10.7.1 Reliability of supply

The reliability of gas supply refers to the continuity of supply to customers. Most jurisdictions impose reliability requirements on gas distributors as part of their licence conditions, and publish (or have published) performance data in this area. In some cases, jurisdictions impose statutory obligations on network operators and owners that relate to the continuity of gas supply.

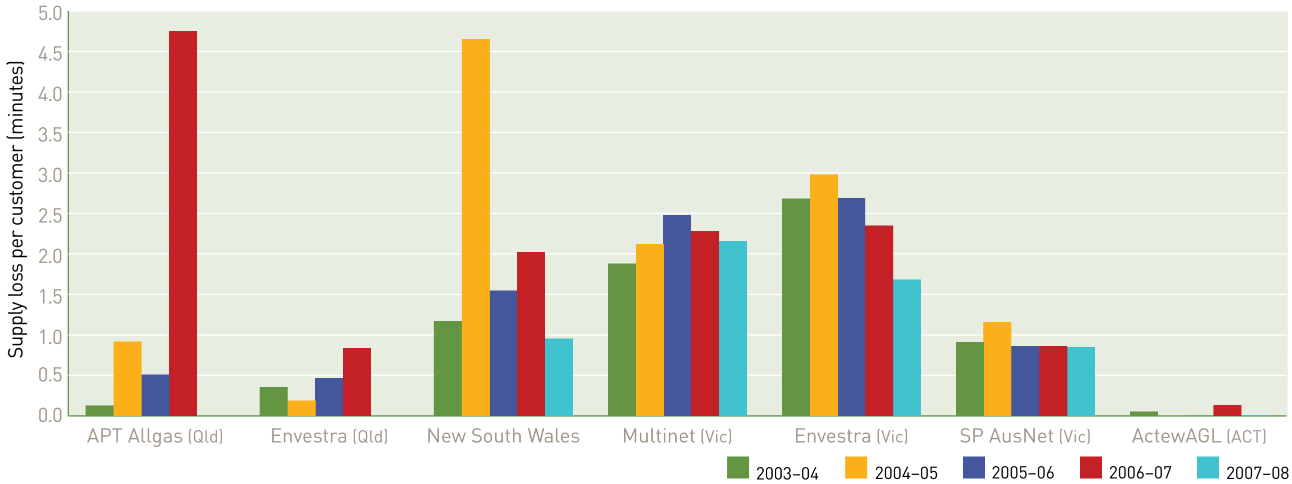
From a reliability perspective, the inherent storage capacity of gas distribution networks can help maintain continuous gas flow to most customers despite a disruption to part of the network. In addition, gas pipes are predominantly buried underground and—unlike electricity networks—are generally not affected by bad weather. In the case of planned renewals—or unplanned incidents such as gas explosions, third party damage, water entering the mains, or directions from the technical regulator—customers in the vicinity of the incident (or those affected by a direction of the regulator) may experience a loss of gas flow.

The generally high rates of network reliability mean a single incident can significantly affect data for a particular year. In particular, there may be significant short term variations in measured performance that result from factors beyond the control of the network providers. When considering network reliability, therefore, it is appropriate to focus on trends over time.

Jurisdictions publish a range of reliability indicators on gas distribution. Some jurisdictions publish reliability indicators similar to those applied in electricity distribution—for example, the average minutes without supply per customer per year (system average interruption duration index, SAIDI). Figure 10.8 sets out time series SAIDI data (unplanned interruptions) for Queensland, New South Wales, Victoria and the ACT. Differences in the jurisdictions' approaches limit the validity of comparisons. Queensland, New South Wales and the ACT account for only unplanned interruptions affecting five or more customers; the Victorian data cover all unplanned interruptions.

The data indicate that an average customer in Victoria and New South Wales is likely to experience gas supply interruptions of less than 3 minutes per year. There is a general trend of improvement in both jurisdictions. Customers in the ACT have experienced negligible supply losses. The Queensland networks generally recorded interruptions of less than 1 minute per customer, in the years for which data are available. Western Australia began publishing SAIDI data in 2009 and reported an average supply loss per customer of 26.8 minutes for WA Gas Networks in 2007–08. Tasmania also reports SAIDI data for its new distribution network, but has cautioned against performance comparisons with mainland jurisdictions until the state's natural gas market becomes more established.

Figure 10.8
Average unplanned gas supply loss per customer per year



Notes:

NSW and ACT data include only unplanned interruptions affecting five or more customers. Victorian data include all unplanned interruptions.

Victoria data are for the calendar year ending in that period. Queensland did not publish 2007–08 data. NSW and ACT data are AER estimates derived from official jurisdictional sources. NSW data are statewide across all networks.

Sources: Network performance reports published by the QCA (Queensland), the Department of Water and Energy (New South Wales), the ESC (Victoria) and the ICRC (ACT).

Another widely used reliability indicator is the number of significant unplanned supply interruptions (affecting five or more customers). Figure 10.9 sets out time series data for Queensland, New South Wales, Victoria and South Australia. Possible variations in underlying definitions limit the validity of comparisons across jurisdictions and networks. In addition, the data have not been normalised to account for differences in network scale or load. The chart does, however, indicate trends in the reliability of particular networks:

> In Victoria, the number of significant unplanned interruptions has ranged from 45 to 83 events per year since 2001 across the three distribution networks. The Essential Services Commission reported in 2008 a deteriorating statewide trend since 2000, but no apparent major issues with distributors' asset management practices. On average, Victorian customers would expect an unplanned gas outage once every 83 years.[14]

> South Australia's Envestra network recorded 13 significant unplanned interruptions in 2007–08 (compared with seven events in the previous year). The Essential Services Commission of South Australia (ESCOSA) reported in 2008 that the number of unplanned interruptions had increased in recent years, citing more intensive measurement practices, and an increase in third party damage resulting from civil and construction activity.[15]

> New South Wales recorded around 54 significant unplanned interruptions across all networks in 2007–08 (compared with 88 the previous year). The number of significant supply interruptions has declined sharply since 2004–05. The New South Wales Department of Water and Energy considered that reduced third party contact with network infrastructure might have contributed to this improvement.[16]

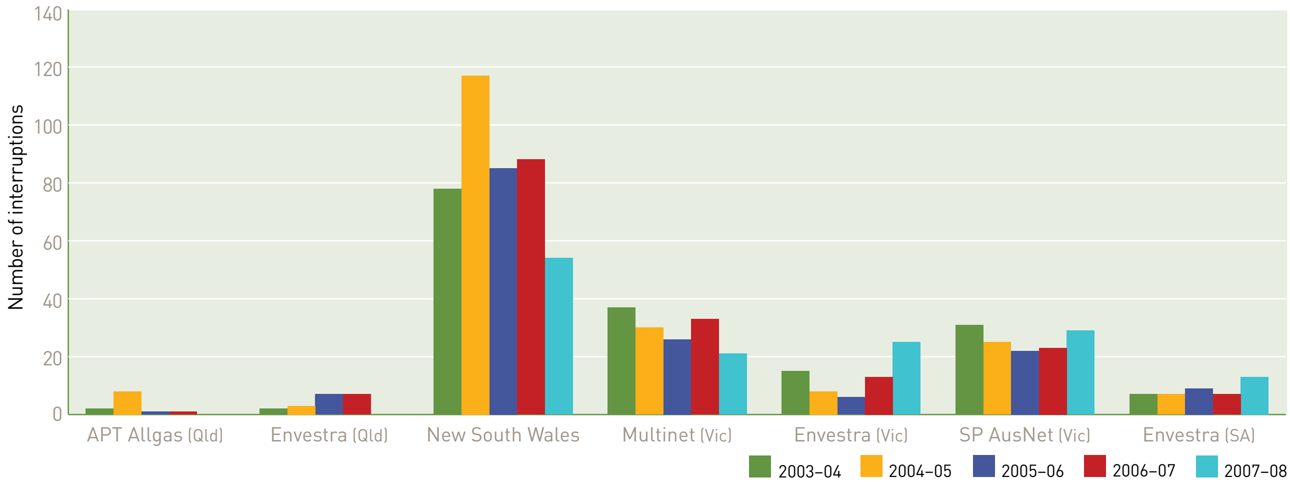
> Queensland recorded relatively few supply interruptions in the years for which data are available.

14 ESC, *Gas distribution businesses: comparative performance report 2007*, Melbourne, 2008, pp. 14, 19, 20.

15 ESCOSA, *2007–08 Annual performance report: South Australian energy networks*, Adelaide, 2008, p. 86.

16 DEUS, *NSW gas networks: performance report 2007–08*, Sydney, 2008, pp. 13–15. Data are AER estimates derived from the DEUS report.

Figure 10.9
Significant unplanned interruptions in gas supply



Notes:

Data cover unplanned interruptions affecting five or more customers.

Victorian data are for the calendar year ending in that period. Queensland did not publish 2007–08 data.

NSW and ACT data are AER estimates derived from official jurisdictional sources. NSW data are statewide across all networks.

Sources: Network performance reports published by the QCA (Queensland), the Department of Water and Energy (New South Wales), the ESC (Victoria) and ESCOSA (South Australia).

10.7.2 Network integrity

Network integrity issues relate to the quality of network infrastructure and associated maintenance practices. Indicators of network integrity include the frequency of gas leaks and repairs, and the amount of unaccounted-for gas. Australian laws require odorant to be added to gas that enters a distribution system. The odorant makes leaks easier to detect. It is usually added at the gate station.

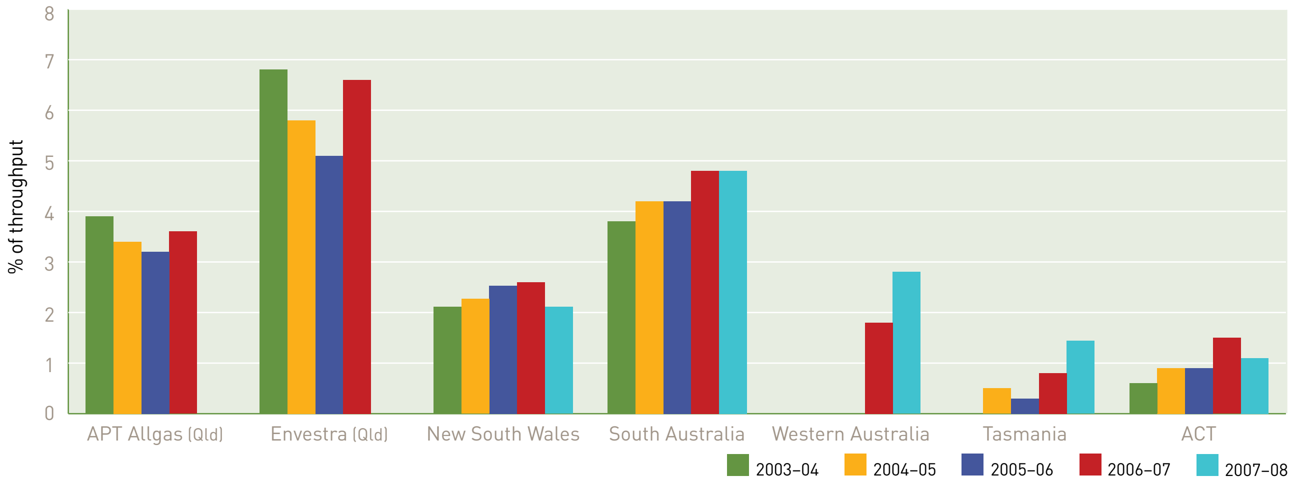
New South Wales, Victoria, Western Australia and the ACT publish data on gas leaks, but the indicators differ across jurisdictions. Some indicators focus on gas leaks reported by the public, while others focus on leaks detected via network surveys. Some indicators focus on total leaks, while others focus on repaired or unrepaired leaks. The range of approaches makes it difficult to compare outcomes between networks in different jurisdictions.

Unaccounted-for gas refers to the difference between the amount of gas injected into a distribution network and the amount of gas delivered to customers. Losses can occur for a number of reasons, including gas leaks, meter reading errors and theft. New South Wales, South Australia, Western Australia and Tasmania report annually on loss data; Queensland ceased publishing the data in 2007. Figure 10.10 sets out the available data from 2003–04. It indicates that up to 7 per cent of gas injected into a distribution network cannot be accounted for. ESCOSA has reported that about 80 per cent of unaccounted-for gas relates to leaks.[17]

The New South Wales Department of Water and Energy considered the performance of the state's distribution networks in 2007–08 to be sound in this area.[18] ESCOSA's 2007–08 performance report noted the proportion of unaccounted-for gas in Envestra's South Australian network is around 6.4 per cent

17 ESCOSA, *2007–08 Annual performance report: South Australian energy networks*, Adelaide, 2008, p. e.
18 Department of Water and Energy (NSW), *NSW gas networks: performance report 2007–08*, Sydney, 2008, p. 8

Figure 10.10
Unaccounted-for gas



Notes:

ACT data are AER estimates derived from official jurisdictional sources.

Queensland did not publish 2007–08 data.

NSW data are statewide across all networks.

Sources: Network performance reports published by the QCA (Queensland), the Department of Water and Energy (New South Wales), ESCOSA (South Australia), the ERA (Western Australia), OTTER (Tasmania) and the ICRC (ACT).

(adjusting for gas delivered through high pressure farm taps that do not leak). ESCOSA considered that a deterioration in the network's unprotected steel and cast iron mains may be contributing to the state's high rate of unaccounted-for gas.[19]

Conversely, the low rate of unaccounted-for gas in Tasmania may reflect the distribution network being relatively new and embodying more recent technology than that of some other networks.

10.7.3 Customer service

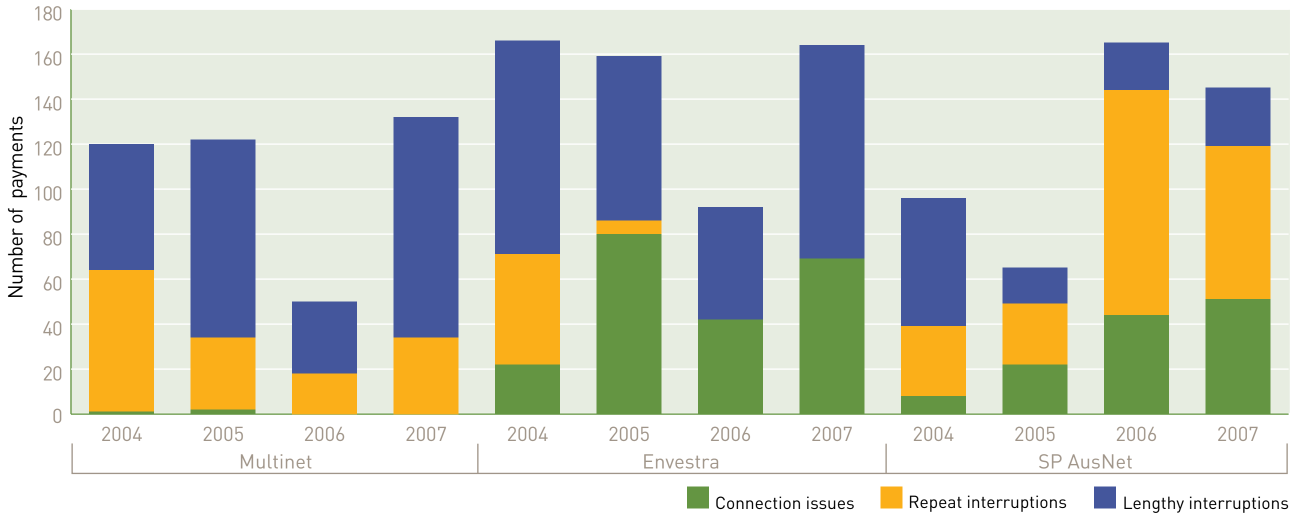
The level of customer service achieved by a distributor can be measured in terms of timeliness and responsiveness across a range of customer interactions, including customer calls, the arrangement of new connections, the keeping of appointments, and the number and nature of complaints about service providers. New South Wales, Victoria, South Australia, Western Australia, Tasmania and the ACT report annually on at least one customer service indicator. Queensland ceased publication of these data in 2007. The use of different indicators across jurisdictions, combined with differences in measurement and auditing systems, makes it difficult to compare outcomes across jurisdictions.

In addition to performance reporting, distributors in Victoria and Western Australia must meet guaranteed service levels or pay penalties for breaches. Figure 10.11 shows trends in the number of payments for the Victorian networks. The data distinguish between the reasons that distributors were obliged to make the payments. Distributors made 444 payments in 2007 worth almost $43 000—an increase of 45 per cent over the previous year's payments. The most significant increase related to lengthy supply interruptions not restored within 12 hours.[20]

19 ESCOSA, *2007–08 Annual performance report: South Australian energy networks*, Adelaide, 2008, p. 82.
20 ESC, *Gas distribution businesses: comparative performance report 2007*, Melbourne, 2008, p. 26.

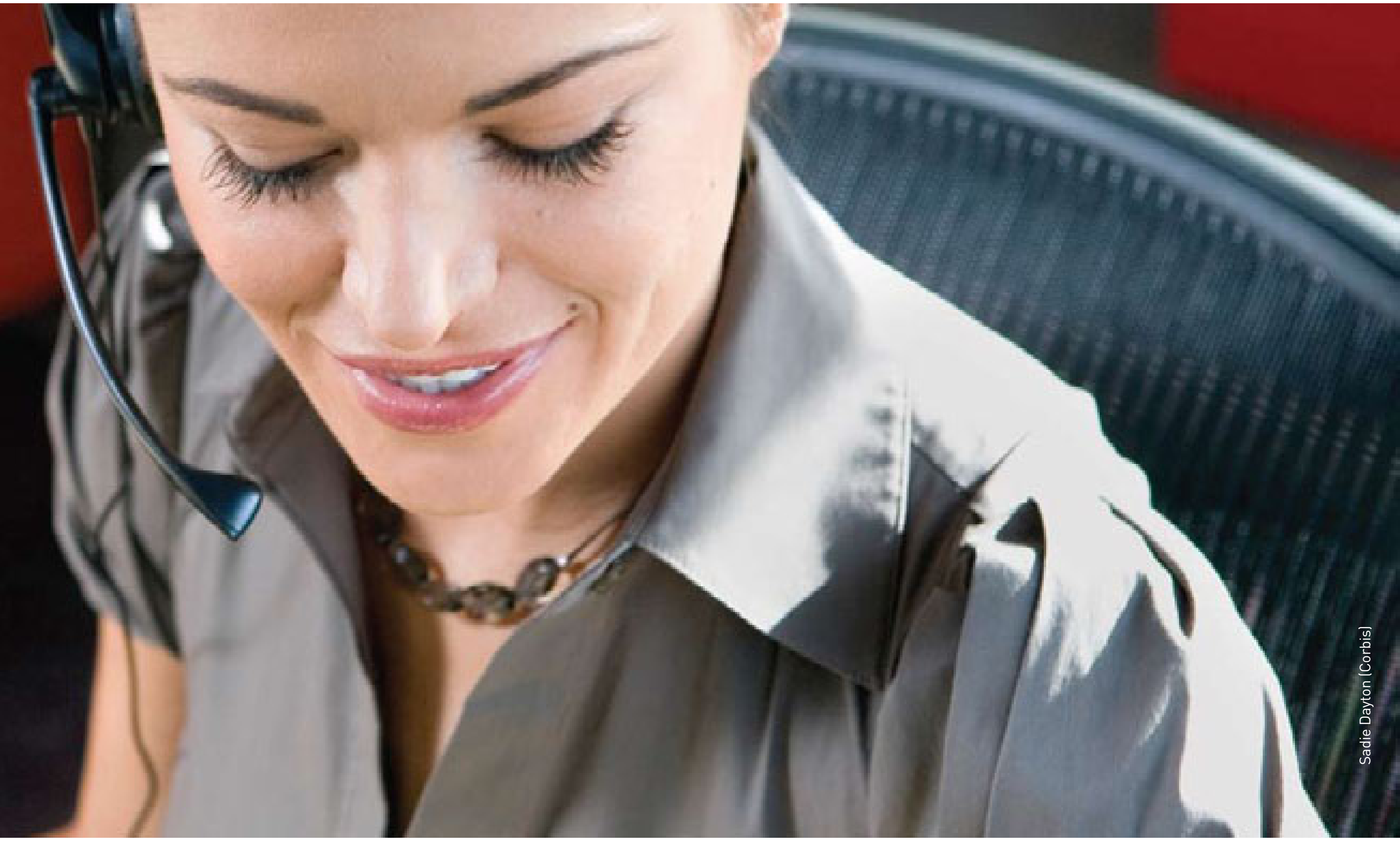
Figure 10.11

Guaranteed service level payments by gas distributors, Victoria



Source: ESC, *Gas distribution businesses: comparative performance report 2007*, Melbourne, 2008.

11 GAS RETAIL


Sadie Dayton (Corbis)

The retail market is the final link in the natural gas supply chain. It provides the main interface between the gas industry and customers such as households and small business. Retailers enter into contracts with gas producers and pipeline operators, and package an aggregated service for sale to customers. Because retailers deal directly with customers, the services they provide significantly affect perceptions of the performance of the gas industry.

11 GAS RETAIL

This chapter provides a survey of natural gas retail markets. It covers:

- the structure of the retail market, including industry participants and trends towards vertical integration
- the development of retail competition
- retail market outcomes, including price, affordability and service quality.

State and territory governments are currently responsible for the regulation of retail energy markets. Governments agreed in 2004, however, to transfer non-price regulatory functions to a national framework for the Australian Energy Market Commission (AEMC) and the Australian Energy Regulator (AER) to administer.[1] The Ministerial Council on Energy (MCE) has scheduled the regulatory package to be introduced to the South Australian parliament in 2010.[2]

Retail customers include residential, business and industrial gas customers. This chapter focuses on the retailing of natural gas to small customers,[3] including households and small business customers. Many energy retailers are active in both gas and electricity markets, and offer dual fuel products. This chapter should thus be read in conjunction with chapter 7, 'Electricity retail'.

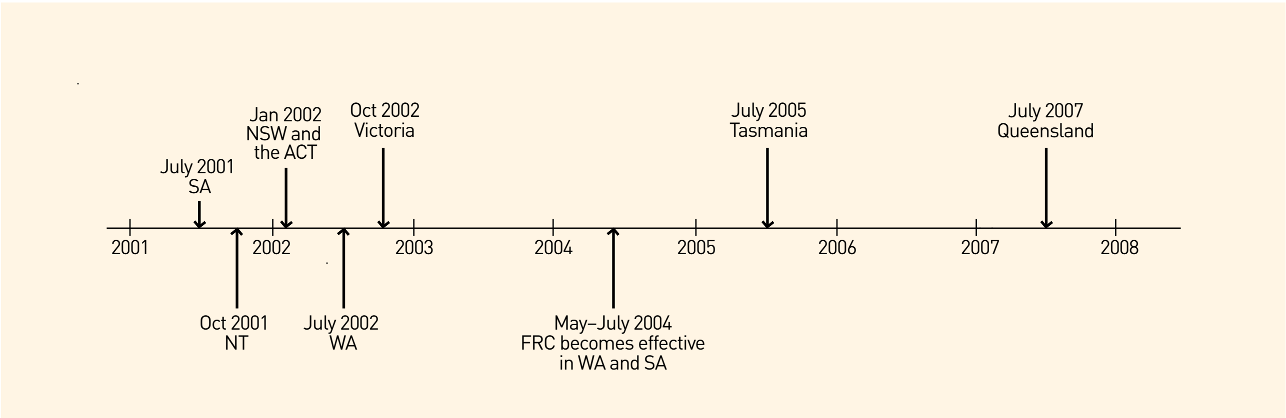
While this chapter reports data that may enable performance comparisons across retailers and jurisdictions, such analysis should note that a variety of factors can affect relative performance.

1 This commitment does not cover regulatory arrangements for gas and electricity retail in Western Australia or electricity retail in the Northern Territory.

2 Sections 11.6 and 7.7 (in chapter 7) provide an update on future regulatory arrangements.

3 Small customers are those using less than 1 terajoule of gas a year.

Figure 11.1
Introduction of full retail contestability



FRC, full retail contestability.

11.1 Retail market structure

Historically, natural gas retailers in Australia were integrated with gas distributors and operated as monopoly providers in their state or region. In the 1990s governments began to reform the industry through restructuring, privatisation and the introduction of competition.

South Australia (in 1993), Victoria (in the late 1990s), Western Australia (in 2000) and Queensland (in 2007) have privatised their state owned gas retailers.[4] While New South Wales has some government ownership, its gas retail sector has always been mainly in private hands.[5] The Australian Capital Territory (ACT) Government operates a joint venture with the private sector to provide gas retail services. Before the formation of the joint venture in 2000, the ACT gas retailer was privately owned. In Tasmania, one of the two active retailers in the state's relatively new gas retail sector is state owned.

All state and territory governments have introduced full retail contestability (FRC) for gas customers, meaning all customers can enter a supply contract with a retailer of choice (figure 11.1). Most governments chose to phase in retail contestability by introducing competition for large industrial customers, followed by small industrial customers and, finally, small business and household customers.

The retail players in most jurisdictions include:

> one or more 'host' retailers, that are subject to additional regulatory obligations
> new entrants, including new players in the gas retail sector, established interstate gas retailers, and electricity retailers branching into gas retailing.

Table 11.1 lists licensed gas retailers that are active in the market for residential and small business customers. Active retailers are those that offer supply contracts to new small customers. Privately owned retailers are the major players in most jurisdictions:

> In the eastern states, the largest retailers are AGL Energy, Origin Energy and TRUenergy. Each has significant market share in Victoria and South Australia. AGL Energy is the largest gas retailer in New South Wales and jointly owns (with the ACT Government) the largest ACT retailer. AGL Energy acquired significant market share in Queensland via the 2006–07 privatisation process, while Origin Energy was already an established retailer in that state.

4 Local councils in Dalby and Roma (Queensland) operate distribution and retail services in their local areas.
5 The New South Wales Government owns EnergyAustralia and Country Energy.

Table 11.1 **Active gas retailers—small customer market, June 2009**

RETAILER[1]	OWNERSHIP	QLD	NSW	VIC	SA	WA	TAS[2]	ACT
ActewAGL Retail	ACT Government and AGL Energy		Host					Host
AGL Energy	AGL Energy	Host	Host	Host	New entrant			
Alinta	Babcock & Brown Power					Host		
Aurora Energy	Tasmanian Government						New entrant	
Australian Power & Gas	Australian Power & Gas			New entrant				
Country Energy	NSW Government		Host					
EnergyAustralia	NSW Government		New entrant					
Origin Energy	Origin Energy	Host	Host	Host	Host			
Red Energy	Snowy Hydro[3]			New entrant				
Simply Energy	International Power			New entrant	New entrant			
Tas Gas Retail (formerly Option One)	Babcock & Brown Infrastructure						New entrant	
TRUenergy	CLP Group		New entrant	Host	New entrant			New entrant
Victoria Electricity	Infratil			New entrant				
Active retailers		2	6	7	4	1	2	2
Approx. market size ('000 000 customers)[4]		0.15	1.19	1.68	0.37	0.58	0.005	0.09

Host (incumbent) retailer   New entrant retailer

1. Not all licensed retailers are listed. Some of the retailers listed offer gas services only as part of a gas and electricity contract. The list excludes three small retailers (BRW Power Generation (Esperance), Dalby Town Council and Roma Town Council).
2. There is no host retailer in Tasmania because gas distribution and retail services have been available only for a short time and FRC existed from market start.
3. Snowy Hydro is owned by the New South Wales Government (58 per cent), the Victorian Government (29 per cent) and the Australian Government (13 per cent).
4. Customer numbers in Queensland, New South Wales and the ACT are estimates based on the number of distribution connection points.

Sources: Jurisdictional regulator websites; ESAA, *Electricity gas Australia 2008*, Melbourne, 2008; updated by information on retailer websites and other public sources.

- In Western Australia, Alinta (owned by Babcock & Brown Power) is the largest retailer and the only retailer licensed to retail to customers consuming less than 0.18 terajoules a year on the main distribution systems.
- Various niche players are active in most jurisdictions.

The following survey (sections 11.1.1–11.1.8) provides background on developments in each jurisdiction.

11.1.1 Queensland

At June 2009 Queensland had seven licensed retailers, of which two were active in the residential and small business market—namely, the host retailers, AGL Energy (previously Sun Gas Retail)[6] and Origin Energy. In addition, the local councils in Dalby and Roma provide gas services in their local government areas. In June 2008 Australian Power & Gas withdrew from actively retailing in the gas retail market because it could no longer viably compete for gas customers.[7] EnergyAustralia obtained a retail licence in July 2007, as did Dodo Power & Gas in January 2008, but neither were actively retailing to small customers in 2009.

6 AGL Energy acquired the government owned Sun Gas Retail in 2006.
7 QCA (Queensland), *Final report—review of small customer gas pricing and competition in Queensland*, Brisbane, November 2008, p. 22.

In a review of small customer gas pricing and competition, the Queensland Competition Authority (QCA) found prices in the small customer gas retail market are not cost-reflective, and the lack of a sufficient retail margin reduces the incentive for new retailers to enter the market.[8] The QCA noted in its final determination that the residential gas retail market in Queensland at June 2008 was almost evenly split between the two host retailers.[9]

11.1.2 New South Wales

At June 2009 New South Wales had 13 licensed retailers, of which six were active in the residential and small business market:

- the host retailers—AGL Energy, Country Energy, Origin Energy and ActewAGL Retail
- two new entrants—electricity retailer EnergyAustralia and established interstate retailer TRUenergy.

Integral Energy and Jackgreen held retail licences in June 2009 but were not actively marketing to small customers.

11.1.3 Victoria

At June 2009 Victoria had 12 retailers licensed to sell gas to residential and small business customers, of which seven retailers were active:

- the host retailers in designated areas of Victoria—TRUenergy, AGL Energy and Origin Energy
- four new players in the gas retail market—Australian Power & Gas, Red Energy, Simply Energy and Victoria Electricity.

Momentum Energy and Dodo Power & Gas held retail licences in June 2009 but were not actively marketing to small customers.

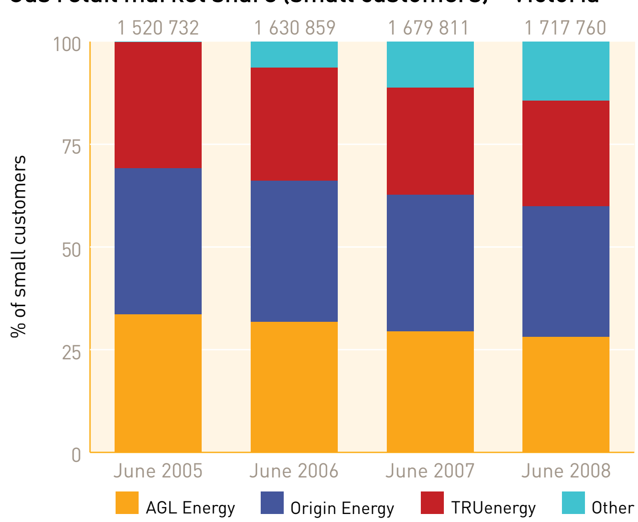
Table 11.2 and figure 11.2 set out the market share of Victorian retailers (by customer numbers) at 30 June 2008. The three host retailers (TRUenergy, AGL Energy and Origin Energy) accounted for about 86 per cent of the market, and each retailed beyond its 'local' area. While the market share of new entrants is small, new entrant penetration increased from 11 per cent of small customers in June 2007 to over 14 per cent in 2008.

Table 11.2 Gas retail market share (small customers)—Victoria, 30 June 2008

RETAILER	CUSTOMERS		
	DOMESTIC (%)	BUSINESS (%)	TOTAL (%)
Origin Energy	32.0	25.7	31.8
AGL Energy	28.0	31.3	28.1
TRUenergy	25.4	36.5	25.7
Other	14.7	6.5	14.4
Total customers (no.)	1 667 371	50 389	1 717 760

Source: ESC (Victoria), *Energy retailers: comparative performance report—customer service 2007–08*, Melbourne, December 2008, p. 5.

Figure 11.2
Gas retail market share (small customers)—Victoria



Note: Figures at top of columns are total small customer numbers.

Source: ESC (Victoria), *Energy retailers: comparative performance report—customer service*, Melbourne, various years.

8 QCA (Queensland), *Final report—review of small customer gas pricing and competition in Queensland*, Brisbane, November 2008, p. 46.

9 QCA (Queensland), *Final report—review of small customer gas pricing and competition in Queensland*, Brisbane, November 2008, p. 24.

CHAPTER 11 GAS RETAIL

11.1.4 South Australia

At May 2009 South Australia had 10 retailers licensed to sell gas to residential and small business customers, of which four retailers were active:

- the host retailer—Origin Energy
- three new entrants—South Australia's host retailer in electricity (AGL Energy), an established interstate retailer (TRUenergy) and Simply Energy (owned by International Power).

Country Energy, EnergyAustralia, Australian Power & Gas, Dodo Power & Gas, Momentum Energy and South Australian Electricity held retail licences but were not actively marketing to small customers in June 2009. Several of these businesses are active in the South Australian electricity retail market. Jackgreen no longer holds a gas retail licence.

Table 11.3 sets out the market share of South Australian retailers (by customer numbers) at June 2008. New entrants accounted for about 42 per cent of the small customer market, up from 40 per cent in 2007 and 30 per cent in 2006 (figure 11.3).

11.1.5 Western Australia

Although the Western Australian retail market is open to retail competition, Alinta is the only active retailer for customers using less than 0.18 terajoules of gas a year. In May 2007 Babcock & Brown Power acquired Alinta's Western Australian gas retail business.

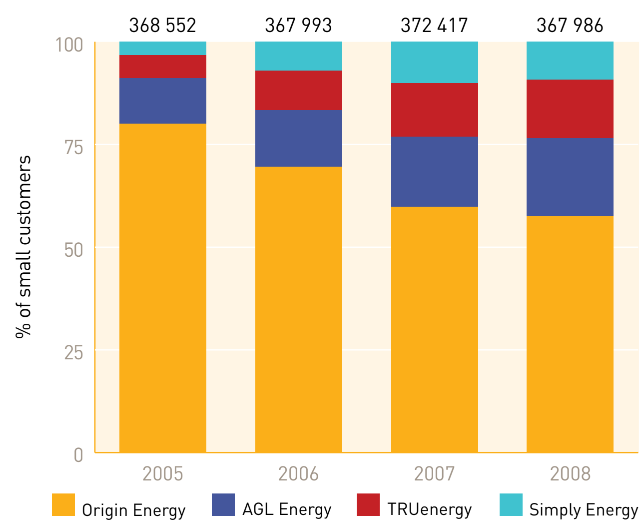
The state's host retailer in electricity, Synergy, applied for a gas trading licence in April 2007 to sell gas to small customers. Restrictions imposed by the Western Australian Government, however, prevent Synergy from supplying gas to customers using less than 0.18 terajoules a year.[10]

Table 11.3 Gas retail market share (small customers)—South Australia, 30 June 2008

RETAILER	CUSTOMERS		
	DOMESTIC (%)	BUSINESS (%)	TOTAL (%)
Origin Energy	56.9	86.4	57.5
AGL Energy	19.3	2.8	19.0
TRUenergy	14.4	8.2	14.2
Simply Energy	9.4	2.6	9.2
Total customers (no.)	360 642	7 344	367 986

Source: ESCOSA (South Australia), *2007–08 Annual performance report: performance of the South Australian energy retail market*, Adelaide, November 2008, p. 70.

Figure 11.3
Gas retail market share (small customers)—South Australia



Note: Figures at top of columns are total small customer numbers.

Source: ESCOSA (South Australia), *Annual performance report: performance of the South Australian energy retail market*, Adelaide, various years.

10 ERA (Western Australia), *Decision on gas trading licence application for Synergy (Electricity Retail Corporation)*, Perth, 26 June 2007.

11.1.6 Tasmania

At June 2009 Tasmania had two gas retailers active in the small customer market: the state owned Aurora Energy and Tas Gas Retail (formerly Option One, owned by Babcock & Brown Infrastructure). TRUenergy and Country Energy obtained retail licences in 2008 but were not actively marketing to small customers in June 2009.

11.1.7 Australian Capital Territory

At June 2009 the ACT had eight licensed retailers, of which two were active in the residential and small business market—namely, the host retailer (ActewAGL Retail) and one new entrant (interstate retailer TRUenergy). EnergyAustralia, Country Energy, Dodo Power & Gas, Australian Power & Gas, Sun Retail and Jackgreen held retail licences in June 2009 but were not actively marketing to small customers.

11.1.8 The Northern Territory

In the Northern Territory, gas is used mainly for electricity generation. NT Gas (owned by the APA Group) supplies a small quantity of gas to commercial and industrial customers in Darwin.

11.2 Trends in market integration

The energy retail sector has undergone considerable ownership consolidation, including:

- retail market convergence between electricity and gas
- vertical integration between gas production and gas retail.

Efficiencies in the joint provision of electricity and gas services have encouraged retailers to be active in both markets, and offer dual fuel retail products. Section 7.2.1 considers the convergence between the gas and electricity retail markets.

There is a continuing trend towards vertical integration between privately owned gas retailers and gas producers. Investment in gas production provides gas retailers with a natural hedge against volatile wholesale gas prices and enhances security of supply. The retailers AGL Energy, Origin Energy and TRUenergy each have interests in gas production and/or gas storage. Origin Energy is a gas producer in Queensland, Western Australia, South Australia and Victoria. AGL Energy has become a producer of coal seam gas in Queensland and New South Wales. TRUenergy has gas storage facilities in Victoria. AGL Energy, Origin Energy and TRUenergy are also major electricity generators.

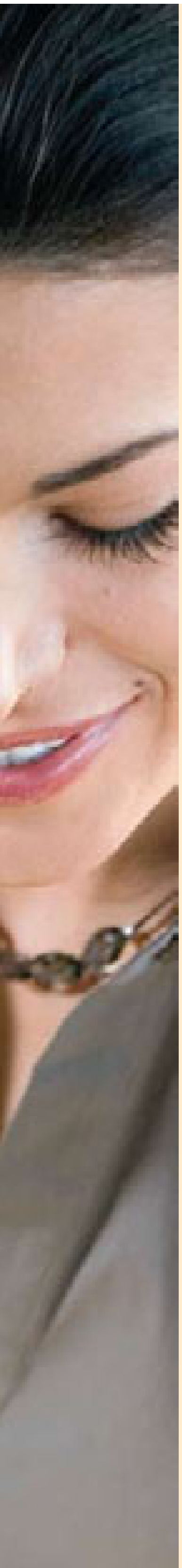
In addition, some ownership links exist between the gas pipeline and gas retail sectors. The retailers TRUenergy and Simply Energy (owned by International Power), for example, have ownership shares in the SEA Gas Pipeline from Victoria to South Australia.

11.3 Retail competition

While most jurisdictions have introduced FRC in gas, it can take time for a competitive market to develop. As a transitional measure, some jurisdictions require host retailers to supply under a regulated standing offer (or default) contract to all small customers without a market contract (see section 11.4.1). Standing offer contracts often cover minimum terms and conditions, and may include a regulated price that is subject to some form of cap or oversight. At July 2009 three jurisdictions—New South Wales, South Australia and Western Australia—applied some form of retail price regulation.

Australian governments have agreed to review the continued use of retail price caps and remove them where effective competition can be demonstrated.[11] The AEMC is assessing the effectiveness of retail competition in each jurisdiction to advise on the appropriate time to remove retail price caps.

11 Australian Energy Market Agreement 2004 (as amended), p. 28.



Box 11.1 Price and product diversity in the small customer market

The CHOICEswitch website (www.choiceswitch.com.au) provides an online estimator service that allows consumers to make quick comparisons of electricity and gas retail offers available in their area. The website also provides information on the terms, conditions and benefits of each offer.

Table 11.4 draws on data available on the CHOICEswitch website to set out the estimated price offerings in June 2009 for customers in selected suburban postcodes in Brisbane, Sydney, Melbourne and Adelaide using 60 gigajoules (GJ) of natural gas a year. The offers were only for the postcodes selected and might not have been available to all customers. The data include all financial discounts and bonuses available under each offer.

The data indicate some price diversity in the gas retail markets, although less than for electricity (see box 7.2 in chapter 7 of this report). Brisbane had the highest price spread of $73 (compared with $666 in electricity), while Melbourne and Sydney had the greatest number of retailers offering contracts to new small customers.

Compared with electricity, there were limited bonuses available under each offer. Only products offered by TRUenergy attracted a discount for prompt payment. No offer included non-financial bonuses such as magazine subscriptions or movie tickets.

In Sydney and Adelaide, where retail gas prices are regulated, only TRUenergy offered products with a discount off the regulated price (of up to 6.9 per cent). Some offers with larger discounts were provided under fixed term contracts with exit fees for early termination.

The range of retailers and products increases if a customer accepts gas retail services as part of a 'dual fuel' retail product (covering both gas and electricity services). In Melbourne, for example, an additional four retailers offered gas retail services as part of a dual fuel product. Some dual fuel products also attracted larger discounts than those for standalone gas retail products.

Table 11.4 Gas retail price offers for a customer using 60 GJ per year in each capital city, June 2009

RETAILER	NO. OF PRODUCTS	ANNUAL COST (INCLUDING DISCOUNTS AND FINANCIAL BONUSES) (800–1700)	DISCOUNTS AND BONUSES INCLUDED IN ANNUAL COST: Pay-on-time bonus	CONTRACT TERM: Fixed term	CONTRACT TERM: Exit fee
BRISBANE (POSTCODE 4032)					
AGL Energy	2	$1596 – $1669	●	●	●
Origin Energy	2	$1669			
SYDNEY (POSTCODE 2148)					
Regulated price (AGL Energy)		$1206			
Energy Australia	1	$1224			
Origin Energy	1	$1206			
TRUenergy	2	$1135 – $1170	●	●	●
MELBOURNE (POSTCODE 3079)					
AGL Energy	1	$883			
Energy Australia	1	$838			
Origin Energy	1	$906			
TRUenergy	3	$839 – $892	●	●	●
ADELAIDE (POSTCODE 5007)					
Regulated price (Origin Energy)	2	$1181			
TRUenergy	2	$1100 – $1146	●	●	●

Note: The offers were only for standalone gas products in the postcodes selected and might not have been available to all customers. The data include all financial discounts and bonuses available under each offer.

Source: CHOICEswitch energy comparison website, viewed 9 June 2009, www.choiceswitch.com.au.

The relevant state or territory government makes the final decision on this matter. The AEMC reviewed the Victorian market in 2007. In response to the review, the Victorian Government removed retail price caps on 1 January 2009.

The AEMC also reviewed the South Australian market in 2008 and outlined options to phase out retail price regulation in that state. The South Australian Government decided in April 2009 not to accept the AEMC's recommendation to remove retail price controls.[12] Box 7.1 in chapter 7 provides further information on the AEMC reviews.

The following is a sample of public data that may be relevant for assessing the effectiveness of retail competition in Australia. The data show the diversity of price and product offerings of retailers; the exercise of market choice by customers, including switching behaviour; and customer perceptions of competition. Elsewhere, this chapter touches on other barometers of competition—for example, section 11.1 considers new entry in the gas retail market. The AER does not seek to draw conclusions from the information provided and does not attempt to assess the effectiveness of retail competition in any jurisdiction.

11.3.1 Price and non-price diversity of retail offers

There is some evidence of price and product diversity in gas retail markets in Australia. Under market contracts, retailers generally offer a rebate and/or discount from the terms of a standing offer contract. Often, discounts are tied to the term of the contract—for example, longer term contracts typically attract larger discounts than do more flexible arrangements. Discounts may also be available for prompt payment of bills and for payments by direct debit.

Some product offerings bundle gas services with inducements such as loyalty bonuses, competitions, membership discounts, shopper cards and free products. Some retailers also offer discounts for contracting jointly for gas and electricity services.

In assessing the effectiveness of competition in gas retail markets in South Australia, the AEMC noted:[13]

> To provide customers with an additional incentive to take up a market offer, retailers also offer other price and non-price incentives such as rebates, one month free supply or bill credits for customers staying longer than one year, or free gifts such as magazine subscriptions, sporting club memberships and appliances. While most retailers offer accredited Greenpower or renewable energy products, some retailers are also offering other innovative products and product features which appeal to customers. Gas customers are offered discounts of between 0.5 and 7.5 per cent in comparison to the gas standing contract prices.

The variety of discounts and non-price inducements makes direct price comparisons between retail offers difficult. Further, the transparency of price offerings also varies. Some retailers publish details of their products and prices, while others require a customer to fill out online forms or arrange a consultation.

The Australian Consumers Association has launched a website—CHOICEswitch—that allows customers to compare energy retail offers. Box 11.1 draws on the website to comment on the diversity of product offerings to small customers in Brisbane, Sydney, Melbourne and Adelaide.

The price offers set out in box 11.1 are not directly comparable across jurisdictions because the underlying product structures may not be identical. For further information on retail prices, see section 11.4.

12 Patrick Conlon (Minister for Energy, South Australia), Letter to the AEMC, 6 April 2009.
13 AEMC, *Review of the effectiveness of competition in electricity and gas retail markets in South Australia—first final report*, Sydney, 19 September 2008, p. 28.

Table 11.5 **Small customers switching retailers, June 2009**

INDICATOR (%)	QUEENSLAND	NEW SOUTH WALES AND THE ACT	VICTORIA	SOUTH AUSTRALIA
Percentage of small customers that changed gas retailer during 2008–09 (%)	16	4	23	11
Customer switches as a percentage of the small customer base from start of FRC to June 2009 (cumulative)—gas (%)	23	30	115	81
Customer switches as a percentage of the small customer base from FRC start to June 2009 (cumulative)—electricity (%)	28.5	56.1	130.7	104.4

Notes:

If a customer switches to a number of retailers in succession, each move counts as a separate switch. Cumulative switching rates may thus exceed 100 per cent.

The customer base is estimated at 30 June 2009. The New South Wales and ACT, Queensland and Victorian data are based on transfers at delivery points.

Sources: New South Wales, ACT: AEMO, Market activity data January 2002 – June 2009; South Australia: REMCo, Market activity reports August 2004 – June 2009; Victoria and Queensland: AEMO, Gas market reports, transfer history January 2002 – June 2009.

11.3.2 Customer switching

The rate at which customers switch their supply arrangements (or churn) is an indicator of customer participation in the market. Switching rates can also indicate competitive activity. High rates of switching can reflect the availability of cheaper or better offers from competing retailers, successful marketing by retailers, and customer dissatisfaction with some service providers.

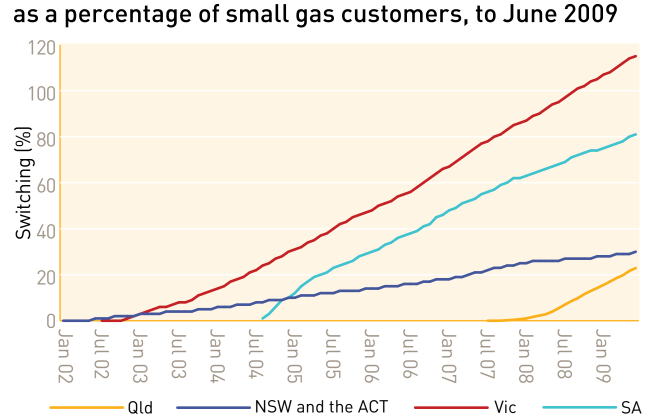
Switching rates should be interpreted with care, however. Switching is sometimes high during the early stages of market development when customers are first able to exercise choice. And switching rates sometimes stabilise even as the market acquires more depth. Similarly, low switching rates are possible in a competitive market if retailers deliver good quality service that gives customers no reason to switch.

Switching rates may also reflect factors such as the number of competitors in the market, customer experience with competition, demographics, demand and the cost of the service in relation to household budgets. Consumers are more likely to be responsive to energy offers and actively seek out cheaper services if, for example, the cost of gas services represents a relatively high proportion of their budget.

Since 1 July 2009 the Australian Energy Market Operator (AEMO) has published gas churn data. Previously, a number of independent market operators—the Gas Market Company (New South Wales and the ACT), VENCorp (Victoria and Queensland) and REMCo (South Australia)—published the data.

Figure 11.4

Cumulative monthly customer switching of retailers as a percentage of small gas customers, to June 2009



Note: The customer base is estimated at 30 June 2009. The New South Wales and ACT, Queensland and Victorian data are based on transfers at delivery points.

Sources: New South Wales and ACT: AEMO, Market activity data January 2002 – June 2009; South Australia: REMCo, Market activity reports August 2004 – June 2009; Victoria and Queensland: AEMO, Gas market reports, transfer history January 2002 – June 2009.

Table 11.6 Customer transfers to market contracts

JURISDICTION	DATE	CUSTOMERS ON MARKET CONTRACTS (% OF CUSTOMER BASE)
Victoria	30 June 2008	54% of gas and electricity customers
South Australia	30 June 2008	62% of residential customers (20% with the host retailer and 42% with new entrants)
		17% of small business customers (3% with the host retailer and 14% with new entrants)
		61% of residential and small business customers (averaged)

Note: South Australian data are for gas customers only.

Sources: ESC (Victoria), *Energy retailers: comparative performance report—customer service 2007–08*, Melbourne, December 2008; ESCOSA (South Australia), *2007–08 Annual performance report: performance of South Australian energy retail market*, November 2008, p. 24.

Churn is measured as the number of switches by gas customers from one retailer to another in a period, including switches from a host retailer to a new entrant, switches from new entrants back to a host retailer, and switches from one new entrant to another (table 11.5 and figure 11.4). The data do not include customers who have switched from a standing offer contract to a market contract with their existing retailer. This exclusion may understate the true extent of competitive activity because it does not account for the efforts of host retailers to maintain market share.

Table 11.5 illustrates switching activity continued strongly in Victoria (and to a lesser extent Queensland and South Australia) in 2008–09. New South Wales and the ACT had a switching rate significantly lower than those recorded in the other states. Only 4 per cent of small customers in New South Wales and the ACT changed gas retailer in 2007–08, compared with 23 per cent in Victoria. Switching activity in South Australia reduced slightly from 13 per cent in 2006–07 to 11 per cent in 2007–08. At June 2009 cumulative switching rates in Victoria (115 per cent) and South Australia (81 per cent) were more than double the New South Wales and ACT rate (30 per cent). More generally, switching rates for gas have been lower than for electricity in all jurisdictions (see table 7.6 in chapter 7).

Switches to market contract

An alternative approach to measuring customer churn is to measure switching from standing offer contracts to market contracts. In June 2008 South Australia was the only jurisdiction that periodically published these data. In Victoria, the Essential Services Commission published data on customer switching to market contracts, but the data combined gas and electricity.

Table 11.6 summarises available data on switches to market contracts in South Australia and Victoria. The data are not directly comparable because collection methods differ.

The data indicate that in addition to customer movement between retailers, a significant number of residential customers are choosing to move away from standing offer contracts. In South Australia, more customers are choosing market contracts with new entrants in preference to the host retailer. Again, switching rates are lower than for electricity (see table 7.7 in chapter 7).

11.3.3 Customer perceptions of competition

A number of jurisdictions undertake occasional surveys on customer perceptions of retail competition. Issues covered include:

- customer awareness of their ability to choose a retailer
- customer approaches to retailers about taking out a market contract
- retailer offers received by customers
- customer understanding of retail offers.

Table 11.7 provides summary data. The surveys suggest customer awareness of retail choice has risen over time to high levels. It remains unusual for customers to approach retailers about taking out a market contract, but retailers are approaching an increasing number of customers.

Table 11.7 **Residential customer perceptions of competition**

INDICATOR	NEW SOUTH WALES[1] Sydney	NEW SOUTH WALES[1] Hunter region	VICTORIA		SOUTH AUSTRALIA	
	2006	2008	2004	2007	2003	2008
Customers aware of choice (%)	92	91	83	91	78	84
Customers receiving at least one retail offer (%)	29[2]	35[2]	22	45	20	20
Customers approaching retailers about taking out market contracts (%)	n/a	7	6	6	8	5

n/a not available.

1. New South Wales data in 2006 are based on a household survey conducted in Sydney, and the 2008 data are based on a similar household survey conducted in the Hunter region.
2. Only includes customers approached by their current retailer about switching to a market contract.

Sources: South Australia: McGregor Tan Research, *Monitoring the development of energy retail competition—residents*, Report prepared for ESCOSA, Adelaide, November 2003; McGregor Tan Research, *Review of effectiveness of competition in electricity and gas retail markets*, Report prepared for the AEMC, Adelaide, June 2008; Victoria: The Wallis Group, *Review of competition in the gas and electricity retail markets—consumer survey*, Report prepared for the AEMC, Melbourne, August 2007; New South Wales: IPART, *Electricity, gas and water research paper—residential energy and water use in the Hunter, Gosford and Wyong*, Sydney, December 2008; IPART, *Residential energy and water use in Sydney, the Blue Mountains and Illawarra—results from the 2006 household survey*, Sydney, November 2007.

11.4 Retail prices

Natural gas retail prices cover the costs of a bundled product made up of gas, transport through transmission and distribution pipelines, and retail services. Data on the composition of residential gas prices are published from time to time in regulatory determinations. Figure 11.5 draws on determinations in Queensland and South Australia to illustrate the typical make-up of a residential gas bill. Wholesale gas costs and pipeline (transmission and distribution) charges account for the bulk of retail gas prices. Retail operating costs and retail margins account for around 36 per cent of retail prices in Queensland and 22 per cent in South Australia.

11.4.1 Regulation of retail prices

While most jurisdictions have introduced FRC, at July 2009 New South Wales, South Australia and Western Australia continued to regulate gas retail prices for small customers. The host retailers in those states must offer standing offer contracts to sell gas at default prices based on some form of regulated price cap or oversight. The contracts apply to customers who have not switched to a market contract. Retail gas prices are not regulated in Queensland, Victoria, Tasmania, the ACT or the Northern Territory.

Price cap regulation was intended as a transitional measure during the development of retail markets. To allow efficient signals for investment and consumption, governments are moving towards removing retail price caps. As noted, the AEMC is reviewing the effectiveness of competition in electricity and gas retail markets to determine an appropriate time to remove retail price caps in each jurisdiction (see section 11.3 and box 7.1 in chapter 7).

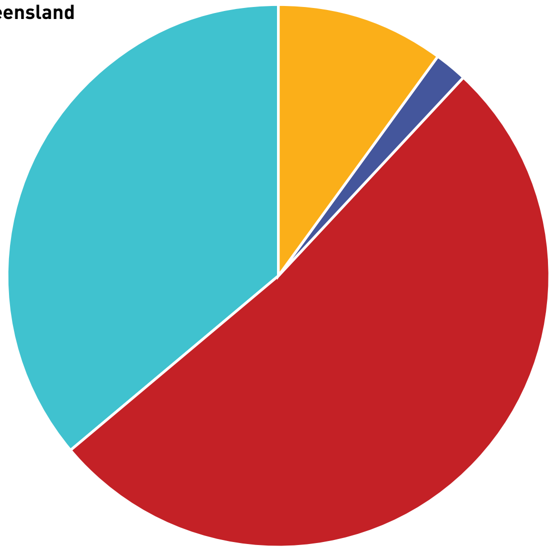
In setting default prices, jurisdictions consider gas purchase costs, pipeline charges, retailer operating costs and a retail margin. The approach varies across jurisdictions:

- In New South Wales, voluntary agreements with host retailers limit annual price increases and thus control prices under standing offer contracts.
- The South Australian regulator (the Essential Services Commission of South Australia, ESCOSA) sets default prices for the host retailer by considering the costs that a prudent retailer would incur in delivering the services.
- In Western Australia, regulations cap gas retail prices for the major distribution systems.

Figure 11.5

Indicative composition of a residential gas bill in Queensland and South Australia, 2008

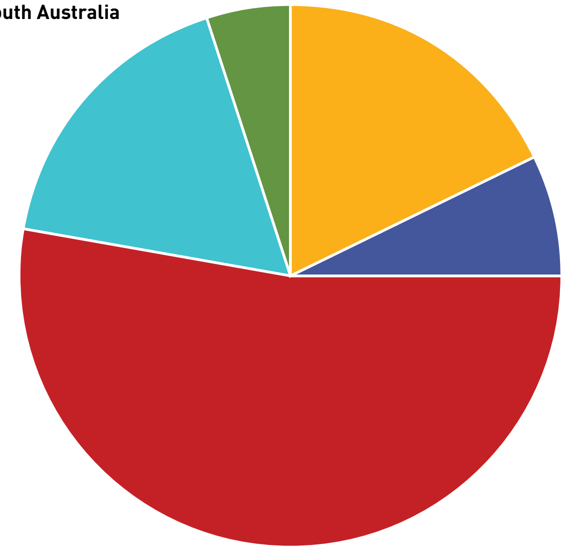
Queensland



Note: Based on McLennan Magasanik and Associates analysis of the composition of costs for a typical residential customer with an annual consumption of 10 gigajoules.

Source: McLennan Magasanik and Associates, *Final report to the Queensland Competition Authority—costs of gas supply for a second tier retailer supplying small customers in Queensland*, Brisbane, November 2008 (report prepared for the QCA review of small customer gas pricing and competition in Queensland).

South Australia



Notes:

South Australian data are based on 2008–09 prices and an average annual residential consumption of 24 gigajoules.

South Australia's retailer tariffs are Origin Energy's 2008–09 standing contract tariffs (Adelaide) and distribution tariffs are Envestra's 2008–09 tariffs.

Source: ESCOSA (South Australia), *2008 Gas standing contract price path inquiry: draft inquiry report and draft price determination*, Adelaide, April 2008.

Table 11.8 compares recent movements in regulated tariffs in New South Wales, South Australia and Western Australia and the mechanisms to allow further tariff revision. The changes relate to the supply of gas by host retailers to customers on default arrangements. Different approaches across jurisdictions reflect a range of factors and must be interpreted with care. In particular, the operating environments of retail businesses differ.

In 2008 the Western Australian Office of Energy reviewed the level and structure of gas tariffs, and made an interim recommendation in June 2009 to increase regulated tariffs by between 7.5 per cent and 23.6 per cent (depending on the customers' geographic location and level of gas consumption).[14] The Western Australian Government accepted this interim recommendation.[15]

The South Australian regulator (ESCOSA) indicated that a typical residential gas bill would increase by 6.15 per cent in 2008–09. This increase largely reflects a rise in network costs, wholesale gas supply costs and an increase in the retail margin.[16]

Queensland does not regulate retail prices but has experienced significant retail price increases since 2005–06 (figure 11.8). In December 2008 the Queensland regulator (the QCA) released a final report

14 Office of Energy, *Gas tariffs review—interim report*, Perth, June 2009.

15 Peter Collier (Minister for Energy, Western Australia), 'Alinta proposal accepted', Media release, 26 June 2009.

16 ESCOSA (South Australia), *2008 Gas standing contract price path inquiry: final inquiry report and final price determination*, Adelaide, June 2008; ESCOSA, *2008–09 Regulated gas price adjustment impact on residential and small business customers*, Adelaide, June 2008.

Table 11.8 Recent changes in regulated gas retail prices

JURISDICTION	PERIOD	RETAILERS	INCREASE IN REGULATED RETAIL PRICE	MECHANISM FOR FURTHER INCREASES IN REGULATED PRICE
New South Wales	1 July 2007 to 30 June 2010	AGL Energy Origin Energy ActewAGL Retail Country Energy	Increase by CPI annually in all areas except the Murray Valley district (Origin), which increases by CPI + 2% annually	Retailers can apply to IPART in special circumstances to vary prices outside the limit.
South Australia	1 July 2008 to 30 June 2011	Origin Energy	2008–09: 8.25% increase 2009–10 to 2010–11: CPI + 1% increase annually	Increased costs incurred from prescribed events can be recovered through tariff increases, and the determination may be reopened.
Western Australia	From 1 July 2009	Alinta	Increase in typical bill of 7.5–23.6%	Government decision will be implemented through regulations.

CPI, consumer price index; IPART, Independent Pricing and Regulatory Tribunal.

Sources: New South Wales: IPART, *Regulated gas retail tariffs and charges for small customers 2007–10: gas final report and voluntary transitional pricing arrangements*, Sydney, June 2007, p. 2; South Australia: ESCOSA, *2008-09 Regulated gas price adjustment impact on residential and small business customers*, Adelaide, June 2008; Western Australia: Energy Coordination (Gas Tariffs) Regulations 2000 and Office of Energy, *Gas tariffs review—interim report*, Perth, June 2008.

on its review of small customer prices and competition in the gas retail market. The QCA noted that retail prices, before the introduction of FRC in 2007, were below the level necessary for a retailer to recover its costs. To bring prices closer to cost-reflective levels, two regulated price increases of 10 per cent were approved in 2005. The QCA found, despite these increases, that prices in the residential gas retail market are still not cost-reflective and the lack of a sufficient retail margin reduces the incentive for new retailers to enter the market.[17]

11.4.2 Retail price outcomes

Retail price outcomes must be interpreted with care. Trends in retail prices may reflect movements in the cost of any one of, or a combination of, the bundled components in a retail product—for example, movements in wholesale gas prices, transmission and distribution pipeline charges or retail operating costs. In addition, regulatory arrangements affect retail price movements. As section 7.4.2 notes, while competition tends to deliver efficient outcomes, it may sometimes give a counter-intuitive outcome of higher prices, especially in the early stages of competition as historical cross-subsidies are phased out.

Sources of price data

There is little systematic publication of actual gas retail prices in Australia. The Australian Gas Association (AGA) previously published data on retail gas prices but discontinued the series after 1998. Some jurisdictions publish price information:

- Jurisdictions that regulate prices publish schedules of default prices. The schedules are a useful guide to retail prices but their relevance as a price barometer is reduced as more customers transfer to market contracts.
- The South Australian regulator (ESCOSA) publishes annual data on default and market prices.
- The Queensland and Victorian regulators (the QCA and the ESC) and ESCOSA provide an estimator service on their websites that can be used to compare the price offerings of retailers.
- In some jurisdictions, retailers are required to publish the prices struck through market contracts with customers.
- The CHOICEswitch website provides a comparison and switching service, to help consumers compare electricity and gas offers (see box 11.1). Other price comparison websites also exist.

17 QCA (Queensland), *Final report—review of small customer gas pricing and competition in Queensland*, Brisbane, November 2008, pp. 31 and 64.

Consumer price index and producer price index

The consumer price index (CPI) and producer price index, published by the Australian Bureau of Statistics, track movements in gas retail prices paid by households and businesses.[18] The indexes are based on customer surveys and, therefore, reflect both market and regulated prices.

Figure 11.6 tracks real gas price movements for households and business customers since 1991. There is considerable disparity between outcomes for each customer type. For business, the real price of gas has fallen by 10.6 per cent since 1991; for households, it has increased by 28.6 per cent (figure 11.7). In part, the disparity reflects the rebalancing of retail prices to remove cross-subsidies from business to household consumers.

It is possible to estimate retail price outcomes for households by using CPI data to extrapolate from the historic AGA price data. Figure 11.8 applies this method to estimate real gas prices for households in several states and territories since July 1996. Real household gas prices have risen since 1996 in all states except Victoria, but the pattern and rate of adjustment have varied. Customers in all states except Queensland experienced real price increases from 2000–01 to 2008–09 of between 19.9 per cent and 25.6 per cent. Prices in Queensland were relatively stable from 2000–01 to 2004–05 but have since risen sharply.

Caution must be exercised when making price comparisons. Price variation across the cities (and across individual customers) reflects a variety of factors, including variations in wholesale gas prices and the distances over which gas must be transported, and differences in regulatory arrangements. Consumption patterns and industry scale also play a role—for example:

> Victoria has a relatively large residential consumer base with consumers located close to major gas fields.
> Queensland prices reflect a small residential customer base and low rates of residential consumption, given that state's warm climate.

18 The producer price index series tracks input costs for manufacturers.

Figure 11.6
Retail gas price index (inflation adjusted)—Australian capital cities, June 1991–March 2009

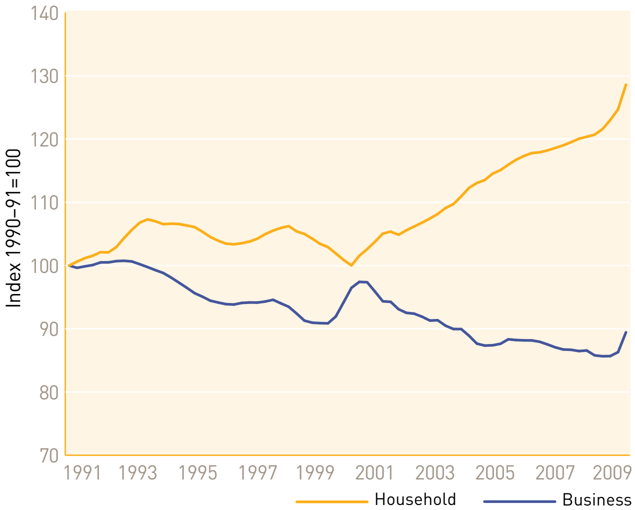
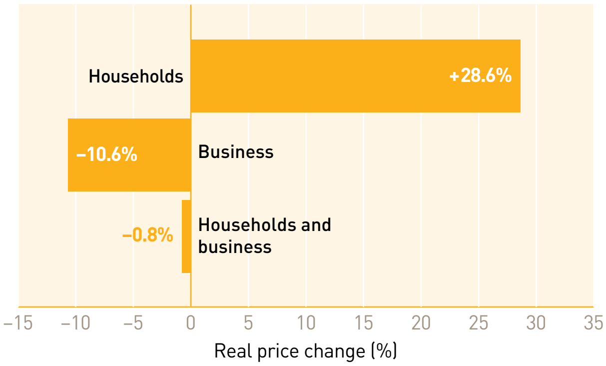


Figure 11.7
Change in the real price of gas—Australia, June 1991–March 2009

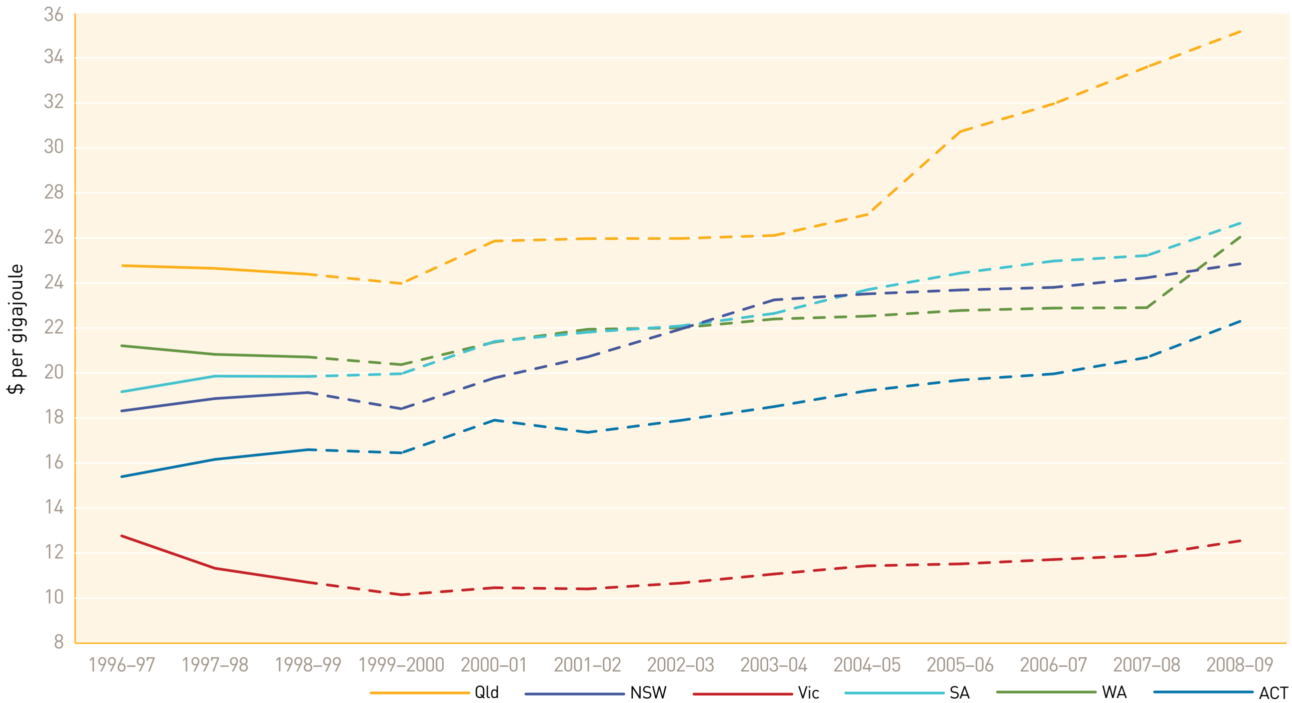


Note to figures 11.6 and 11.7: The households index is based on capital city consumer price indexes for 'gas and other household fuels' deflated by the capital city CPI series for all groups. The business index is based on the producer price index for gas supply in 'Materials used in manufacturing industries' deflated by the CPI series for all groups. The household index was affected by the introduction of the Goods and Services Tax (GST) on 1 July 2000, which increased prices paid by households for gas services.

Sources for figures 11.6 and 11.7: ABS, *Consumer price index* and *Producer price index, March quarter 2009*, cat. nos. 6401.0 and 6427.0, Canberra, various years.

Figure 11.8

Real retail gas prices, by state and territory, July 1996–March 2009



Note: The dashed lines are estimates based on inflating 1998–99 AGA data by the CPI series for gas and other household fuels for the capital city in that state.

Sources: AGA, *Gas statistics Australia*, Canberra, August 2000, p.73; ABS, *Consumer price index, Australia, March quarter 2009*, cat. no. 6401.0, Canberra.

> Western Australia traditionally has relatively low wholesale gas prices but high transport costs because most residential consumers are located a long distance from gas basins. Volumes are also relatively low.

11.5 Quality of retail services

Competition provides incentives for retailers to improve performance and quality of service as a means of maintaining or increasing market share. In addition, governments have established regulations and codes on minimum terms and conditions, information disclosure and complaints handling requirements, which retailers must meet when supplying gas to small customers. As discussed in section 7.5, jurisdictional regulators monitor and report on retail service quality to enhance transparency and accountability. Most jurisdictions also have an ombudsman to investigate and report on complaints.

In November 2000 the Utility Regulators Forum (URF) established the Steering Committee on National Regulatory Reporting Requirements. The steering committee developed a national framework in 2002 for electricity retailers to report against common criteria on service performance. In May 2007 the steering committee recommended extending national reporting arrangements for electricity retail businesses to include the gas retail sector from 2007–08.[19] It developed reporting criteria that address:

> customer affordability and access to services
> quality of customer services.

19 URF, *National energy retail performance indicators—final paper*, Canberra, May 2007, p. ii.

New South Wales, Victoria, South Australia, Western Australia and the ACT have reported performance against the URF indicators, but each jurisdiction applies different methods and assumptions. These differences may limit the validity of any national performance comparisons across jurisdictions.

11.5.1 Affordability and access indicators

The rate of residential customer disconnections for failure to meet bill payments (figure 11.9) and the rate of disconnected customers reconnected within seven days (figure 11.10) are key affordability and access indicators.

In 2007–08 the rate of residential customer disconnections rose against the previous year's rate in South Australia and Western Australia, remained below 1 per cent in Victoria, and fell in New South Wales and the ACT. The rate at which disconnected customers were reconnected in 2007–08 improved in all states.

11.5.2 Customer service indicators

Customer service measures indicate customer satisfaction with the quality of retailer service. Indicators include:

- the percentage of customer calls answered within 30 seconds (figure 11.11)
- retail customer complaints as a percentage of total customers (figure 11.12).

Call centre performance varied across the jurisdictions in 2007–08. In Victoria, the number of calls answered within 30 seconds fell from 80 per cent in 2006–07 to 78 per cent in 2007–08, while the rate in South Australia improved from 81.9 per cent to 84.6 per cent over the same period. New South Wales improved from 60 per cent in 2006–07 to 75 per cent in 2007–08.

The rate of gas complaints by residential customers was around 0.5 per cent of the customer base in New South Wales, Victoria and South Australia in 2007–08. The rate increased significantly in the ACT, from 0.14 per cent in 2005–06 to 0.76 per cent in 2007–08. In Western Australia, the rate of gas complaints by residential customers remained unchanged at 0.15 per cent. In South Australia, ESCOSA noted that the increase in 2007–08 was principally due to a large increase in complaints reported by AGL Energy following the first phase of conversion of South Australian gas customers to a new billing system in late 2007.[20]

As noted in section 7.4.2, customers have a range of options to redress customer service issues: customers can raise complaints directly with their retailer, refer complaints to their state energy ombudsman or transfer away from a business providing poor service.

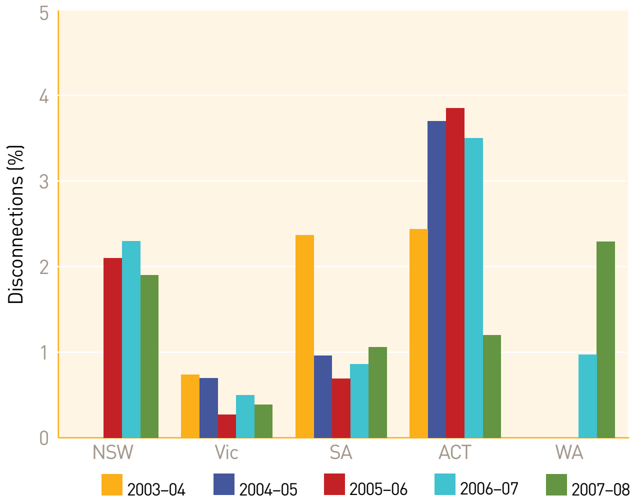
11.5.3 Consumer protection

Governments regulate aspects of the energy retail market to protect consumers' rights and ensure customers have access to sufficient information to make informed decisions. New South Wales, South Australia and Western Australia require designated host retailers to provide gas services under a standard contract to nominated customers. Standard contracts cover minimum service conditions relating to billing, procedures for connections and disconnections, information disclosure and complaints handling. During the transition to effective competition, default contracts also include regulated retail tariffs (see section 11.4.1).

While prices in Queensland are not regulated, host retailers are required to offer small customers a standard contract. This contract must be published on the retailers' website and notified to the Queensland regulator (the QCA).

20 ESCOSA (South Australia), *2007–08 Annual performance report: performance of South Australian energy retail market*, Adelaide, p. h.

Figure 11.9
Gas residential disconnections, as a percentage of the customer base



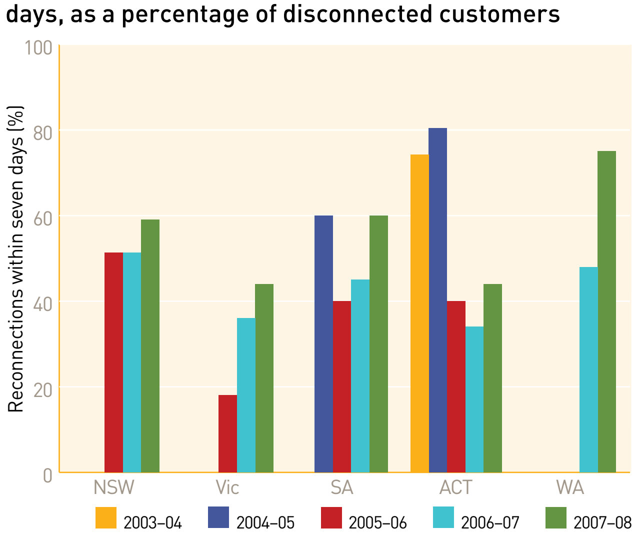
Notes:

ACT figures include residential and non-residential customers but exclude disconnections by Energy Australia.

New South Wales data are available only from 2005–06. Western Australia data are available only from 2006–07. Tasmania data are available, but the rates for disconnection and customer complaints are negligible and have not been included in the chart.

Source: see figure 11.12.

Figure 11.10
Residential gas customers reconnected within seven days, as a percentage of disconnected customers



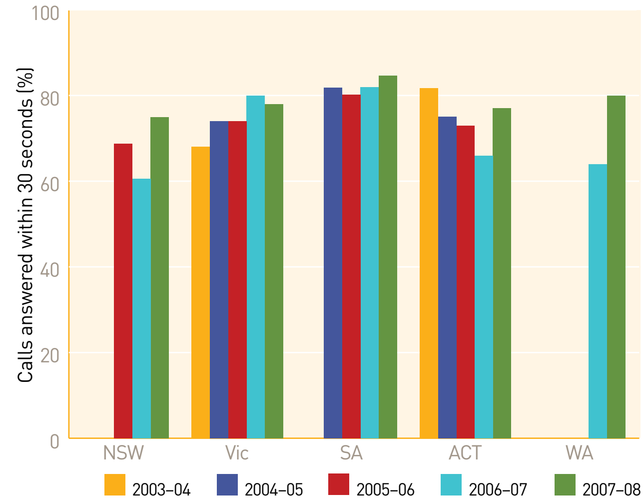
Notes:

Victorian data for 2005–06 include only six months of data from January–June 2006.

New South Wales and Victorian data are available only from 2005–06. South Australian data are available only from 2003–04. Western Australia data are available only from 2006–07.

Source: see figure 11.12.

Figure 11.11
Percentage of gas retail customer calls answered within 30 seconds



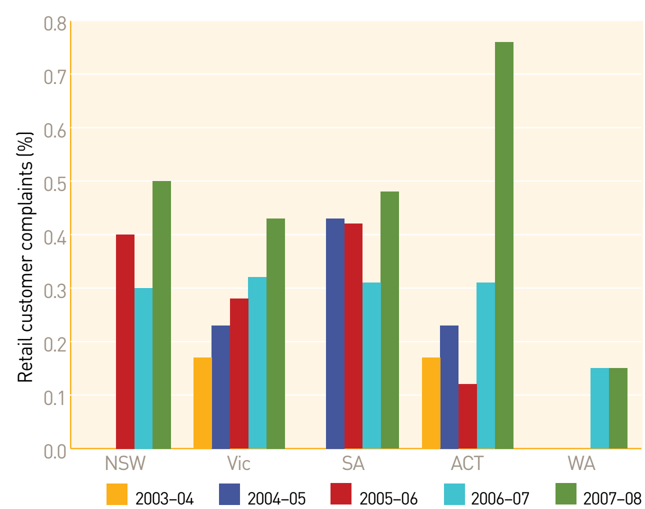
Notes:

South Australia and Victorian data in 2007–08 are for both gas and electricity.

New South Wales data are available only from 2005–06. South Australian data are available only from 2004–05. Western Australia data are only available from 2006–07.

Source: see figure 11.12.

Figure 11.12
Retail gas customer complaints, as a percentage of total customers



Note: New South Wales data are available only from 2005–06. South Australian data are available only from 2004–05. Western Australia data are available only from 2006–07.

Sources for figures 11.9, 11.10, 11.11 and 11.12: Reporting against URF templates and performance reports on the retail sector by IPART (New South Wales), the ESC (Victoria), ESCOSA (South Australia), the ERA (Western Australia) and the ICRC (ACT).

Some jurisdictions have established industry codes that apply to all retail gas services, including those sold under market contracts. The codes govern market conduct and establish minimum terms and conditions under which a retailer can sell gas to small retail customers. They may:

- constrain how retailers may contact potential customers
- require pre-contract disclosure of information, including commissions for market contracts
- provide for cooling-off periods
- provide rules for the conduct of door-to-door sales, telemarketing and direct marketing.

Most jurisdictions also have an energy ombudsman or alternative dispute resolution body to whom consumers can refer a complaint they were unable to resolve directly with the retailer. In addition to general consumer protection measures, some jurisdictions have introduced 'retailer of last resort' arrangements to ensure customers can transfer from a failed or failing retailer to another retailer. Section 7.5.3 provides further background on consumer protection arrangements for energy retail customers.

11.6 Future regulatory arrangements

Governments agreed in the Australian Energy Market Agreement 2004 (as amended) that jurisdictions other than Western Australia would transfer non-price regulatory functions to a national framework for the AEMC and the AER to administer. These functions include:

- the obligation on retailers to supply small customers
- small customer market contracts and marketing
- retailer business authorisations, ring-fencing and retailer failure
- balancing, settlement, customer transfer and metering arrangements
- enforcement mechanisms and statutory objectives.[21]

The Northern Territory will be transferring only non-price regulatory functions for gas retail.

The MCE has scheduled the regulatory package for the transfer of functions to be introduced to the South Australian parliament in 2010. The arrangements are occurring in tandem with equivalent arrangements in electricity. Section 7.7 in chapter 7 outlines progress.

21 Australian Energy Market Agreement 2004 (as amended).

APPENDIX: ENERGY MARKET REFORM

In 2004 the Australian, state and territory governments set the agenda for a transition to national energy regulation, with the Australian Energy Market Agreement. The 2006 revisions to that agreement underpin the most recent wave of reform. They include streamlined regulatory, planning, governance and institutional arrangements for the national electricity and gas markets.

ENERGY MARKET REFORM

A.1 Institutional framework

At the national level, two intergovernmental bodies determine the direction of Australia's energy policy: the Council of Australian Governments (COAG) and the Ministerial Council on Energy (MCE). The peak intergovernmental forum in Australia, COAG comprises the prime minister, state premiers, territory chief ministers and the president of the Australian Local Government Association. Its role is to initiate, develop and monitor the implementation of policy reforms that are nationally significant and that require cooperative action by Australian governments. These reforms include energy market reform.

The MCE comprises Australian, state and territory energy ministers. Ministers from New Zealand and Papua New Guinea have observer status. The MCE's role is to initiate and develop energy policy reforms for consideration by COAG. It also monitors and oversees the implementation of energy policy reforms agreed by COAG. The Standing Committee of Officials is a group of senior officials from the Australian, state and territory governments who assist the MCE.

In addition, special-purpose bodies have been created to develop and implement reform packages for the energy sector:

- In 2006 COAG established an Energy Reform Implementation Group (ERIG) to report on measures that may be necessary to achieve a fully national electricity transmission grid. ERIG also addressed industry structure and financial market issues that may affect the ongoing efficiency and competitiveness of the energy sector.
- The MCE established:
  - the Retail Policy Working Group to oversee the transfer of energy distribution (non-economic) and retail regulation functions to the national legislative framework
  - an industry led Gas Market Leaders Group to produce a market development plan for the gas wholesale sector.

Other key agencies in the national energy framework are:

> the Australian Energy Regulator (AER), which is the independent national energy market regulator
> the Australian Energy Market Commission (AEMC), which is responsible for rule making and market development in the national electricity and gas markets. It also reviews the energy market framework and provides policy advice to the MCE.
> the Australian Energy Market Operator (AEMO), which is responsible for the day-to-day operation and administration of the power system and the electricity and gas wholesale and retail markets in all jurisdictions except Western Australia and the Northern Territory.

Although the AER, the AEMC and AEMO are not policy bodies, each participates in energy market reform processes. Figure A.1 outlines the roles and responsibilities of key bodies involved in national energy policy, regulation and market operation.

A.2 Transition to a national energy framework

The AER and the AEMC were established under the Australian Energy Market Agreement and began on 1 July 2005. The transfer of functions from state and territory regulators, however, is still in progress. Table A.1 sets out the institutional arrangements that will apply once the transfer of functions is complete.

Market monitoring, compliance and enforcement

The AER monitors and enforces compliance with national energy market legislation, including the National Electricity Law and Rules and the National Gas Law and Rules. This role encompasses compliance with the law and rules governing network regulation, the wholesale electricity market, the Victorian wholesale gas market, the National Gas Market Bulletin Board and jurisdictional retail gas market procedures. These functions have transferred gradually since the AER's inception, with the most recent functions (relating to the Victorian wholesale gas market and retail gas market procedures) incorporated in the National Gas Law from 1 July 2009.

Electricity networks

The AER has been responsible for the regulation of electricity transmission networks since 1 July 2005—a role previously undertaken by the Australian Competition and Consumer Commission (ACCC). On 1 January 2008 revisions to the Electricity Law and Rules refined the regulatory process for electricity networks. The new framework also established the AER as the economic regulator of electricity distribution networks in the National Electricity Market (NEM) jurisdictions.[1]

In 2008 the AER released guidelines to assist electricity distribution businesses and their customers to understand the AER's approach to distribution network regulation. It also released details of the incentive schemes to apply to electricity distribution businesses. The AER's first revenue determinations for electricity distribution were completed in April 2009 for the New South Wales and Australian Capital Territory (ACT) network businesses.

Gas networks

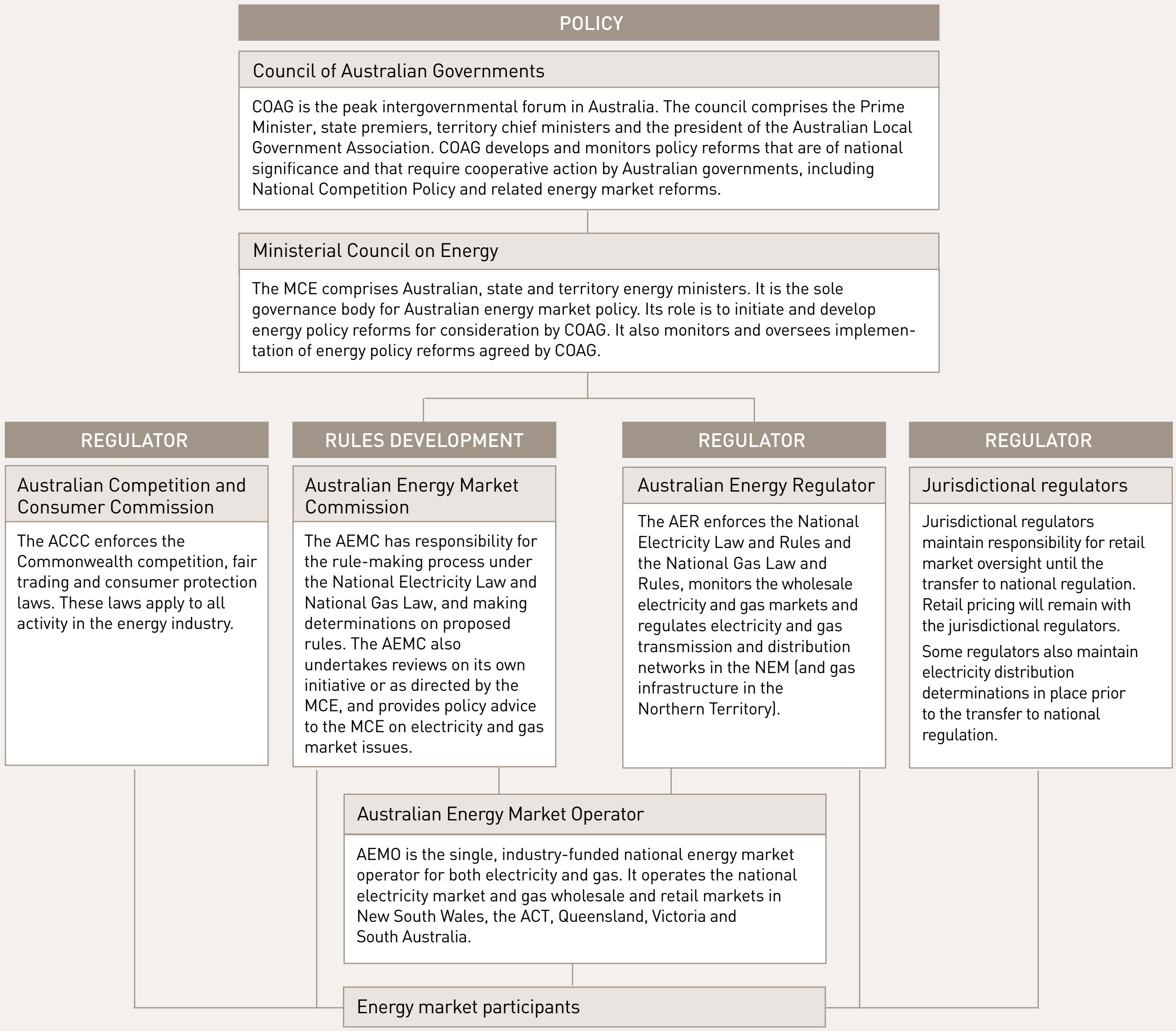
The Gas Law and Rules, which took effect on 1 July 2008, provide the regulatory framework for the gas transmission and distribution sectors. These instruments replace the Gas Pipelines Access Law and the National Gas Code, which had provided the regulatory framework since 1997.

The new legislation transferred the regulation of covered distribution pipelines outside Western Australia from state and territory regulators to the AER. It also transferred the regulation of covered transmission pipelines outside Western Australia from the ACCC to the AER. As of July 2009 the AER regulated eight transmission pipelines[2] and 11 distribution networks.[3]

1 The regulation of transmission and distribution networks in Western Australia and the Northern Territory remains under state and territory jurisdiction.
2 Two transmission pipelines are subject to light regulation.
3 Western Australia has three covered transmission pipelines and one covered distribution network. The Economic Regulation Authority regulates these assets.

Figure A.1

National energy market—institutional framework



AEMC, Australian Energy Market Commission; AEMO, Australian Energy Market Operator; AER, Australian Energy Regulator; ACCC, Australian Competition and Consumer Commission; COAG, Council of Australia Governments; MCE, Ministerial Council on Energy; NEM, National Electricity Market.

Table A.1 **Energy regulation after implementation of national framework**

<table>
<tr><th></th><th>QLD</th><th>NSW</th><th>ACT</th><th>VIC</th><th>SA</th><th>TAS</th><th>NT</th><th>WA</th></tr>
<tr><td>Gas transmission</td><td colspan="7" rowspan="2">Australian Energy Regulator</td><td rowspan="7">Economic Regulation Authority</td></tr>
<tr><td>Gas distribution</td></tr>
<tr><td>Electricity wholesale</td><td colspan="6" rowspan="4">Australian Energy Regulator</td><td rowspan="5">Utilities Commission</td></tr>
<tr><td>Electricity transmission</td></tr>
<tr><td>Electricity distribution</td></tr>
<tr><td>Retail (non-price)</td></tr>
<tr><td>Retail (pricing)</td><td>QCA</td><td>IPART</td><td>ICRC</td><td>ESC</td><td>ESCOSA</td><td>OTTER and GPOC</td></tr>
</table>

Rule changes	Australian Energy Market Commission
Competition regulation	Australian Competition and Consumer Commission

ESC, Essential Services Commission (Victoria); ESCOSA, Essential Services Commission of South Australia; GPOC, Government Prices Oversight Commission (Tasmania); ICRC, Independent Competition and Regulatory Commission (ACT); IPART, Independent Pricing and Regulatory Tribunal (New South Wales); OTTER, Office of the Tasmanian Economic Regulator; QCA, Queensland Competition Authority.

In September 2008 the AER released guidelines to assist gas network businesses and their customers to understand the AER's approach to the regulation of gas distribution businesses.

Retail

The Retail Policy Working Group recommended retail functions for transfer to national regulation. It reviewed:

- retailer obligations for supply to small customers
- customer market contracts
- marketing
- business authorisations
- ring-fencing
- retailer failure arrangements (retailer of last resort).[4]

The MCE released a first exposure draft of the National Energy Customer Framework for consultation in April 2009. Under the draft legislation, the AER will:

- be a gatekeeper for authorisation and exemptions
- publish standing tariffs
- monitor and enforce:
  - customer financial hardship policies
  - compliance with the terms of regulated contracts and rules
  - marketing conduct
- issue guidance to market participants on how to apply the new framework and on the AER's enforcement strategy.

The MCE is expected to release a second exposure draft in late 2009, with the final legislative package to be introduced to the South Australian Parliament in the 2010 spring session. States and territories will transition to the national framework as it is adopted through legislation in each relevant jurisdiction.

A.2.1 The Australian Energy Market Operator

In April 2007 COAG agreed to establish AEMO as a single, industry funded national energy market operator for both electricity and gas.[5] Established as a corporate entity that operates on a cost recovery basis, AEMO began operating on 1 July 2009. Its membership is split between government (60 per cent) and industry (40 per cent). Government members include the Australian Government and the state and territory governments of all jurisdictions in which AEMO operates.

4 MCE, *Communiqué*, 19 May 2006.
5 COAG, *Communiqué*, 13 April 2007.

The organisation merges the roles of the national electricity market operator (previously undertaken by the National Electricity Market Management Company) with the wholesale and retail gas market operators in New South Wales, the ACT, Queensland, Victoria and South Australia. It also assumes the state based electricity planning functions of VENCorp (in Victoria) and the Electricity Industry Supply Planning Council (in South Australia).

As the electricity market operator, AEMO manages the wholesale NEM and is responsible for scheduling and dispatching generating plant, managing transmission constraints and settling the market. In its gas market role, AEMO operates the Victorian wholesale spot market, wholesale arrangements in other states and territories (and, from 1 July 2010, the short term trading market), the Gas Market Bulletin Board and retail functions, including customer transfers and management of the daily allocation of gas use to retailers. It also oversees the system security of the NEM electricity grid and the Victorian gas transmission network.

The new functions of AEMO include:

> planning and coordinating the development of the national electricity transmission network

> preparing an annual Gas Statement of Opportunities (GSOO).

The National Transmission Planner (NTP) role aims to strengthen transmission planning arrangements in the NEM. In particular, it will move the planning focus away from priorities of individual jurisdictions, onto the national grid as a whole.

The NTP will publish an annual national transmission network development plan outlining the efficient development of the power system. The plan will provide a long term strategic outlook (minimum 20 years), focusing on national transmission flow paths. It will not replace local planning and will not be binding on transmission businesses or the AER. Rather, the plan will complement shorter term investment planning by transmission businesses. A national transmission statement is to be published by the end of 2009 as a first step. The first full national transmission network development plan will be completed by the end of 2010.

The GSOO will be an annual publication similar to the current Electricity Statement of Opportunities. These two publications will provide 10 year outlooks for electricity and gas requirements across eastern and southern Australia. AEMO's first GSOO is scheduled for publication in December 2009.


Frank Bodenmueller (Corbis)

ABBREVIATIONS

1P	proved reserves
2P	proved plus probable reserves
3P	proved plus probable plus possible reserves
AASB	Australian Accounting Standards Board
ABARE	Australian Bureau of Agricultural and Resource Economics
ABS	Australian Bureau of Statistics
AC	alternating current
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
AEMA	Australian Energy Market Agreement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFMA	Australian Financial Markets Association
AGA	Australian Gas Association
AMIQ	authorised maximum interval quantity
AMSP	alternative maximum STEM price
BBI	Babcock & Brown Infrastructure
BBP	Babcock & Brown Power
CAIDI	customer average interruption duration index
CBD	central business district
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CNOOC	China National Offshore Oil Company
CO_2	carbon dioxide
COAG	Council of Australian Governments
CPI	consumer price index
CPRS	Carbon Pollution Reduction Scheme
CPT	cumulative price threshold
CSG	coal seam gas
DC	direct current
EBIT	earnings before interest and tax
EBITDA	earnings before interest, tax, depreciation and amortisation
Electricity Law	National Electricity Law
Electricity Rules	National Electricity Rules
ERA	Economic Regulation Authority (Western Australia)
ERIG	Energy Reform Implementation Group
ESAA	Energy Supply Association of Australia
ESC	Essential Services Commission (Victoria)
ESCOSA	Essential Services Commission of South Australia
ESOO	Electricity Statement of Opportunities (published by AEMO)
ETEF	Electricity Tariff Equalisation Fund
FEED	front end engineering design
FID	final investment decision
FRC	full retail contestability
Gas Law	National Gas Law
Gas Rules	National Gas Rules
GEAC	Great Energy Alliance Corporation
GJ	gigajoules
GSL	guaranteed service level
GSOO	Gas Statement of Opportunities
GWh	gigawatt hour
ICRC	Independent Competition and Regulatory Commission
IEA	International Energy Agency
IMO	Independent Market Operator
IPART	Independent Pricing and Regulatory Tribunal
JV	joint venture
kV	kilovolt
kVa	kilovolt amperes
kW	kilowatt
kWh	kilowatt hour
LNG	liquefied natural gas
MAIFI	momentary average interruption frequency index
MCC	marginal cost of constraints
MCE	Ministerial Council on Energy

MW	megawatt
MWh	megawatt hour
MVa	megavolt amperes
NCC	National Competition Council
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NPI	National Power Index
NTP	National Transmission Planner
NWIS	North West Interconnected System
OCC	outage cost of constraints
OCGT	open cycle gas turbine
OECD	Organisation for Economic Cooperation and Development
OTC	over-the-counter
OTTER	Office of the Tasmanian Economic Regulator
PASA	projected assessment of system adequacy
PJ	petajoule
PV	photovoltaic
Q	quarter
QCA	Queensland Competition Authority
QNI	Queensland to New South Wales interconnector
RAB	regulated asset base
RERT	reliable and emergency reserve trader
RET	renewable energy target
RIT-T	Regulatory Investment Test for Transmission
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCONRRR	Steering Committee on National Regulatory Reporting Requirements
SEA Gas	South East Australia Gas
SFE	Sydney Futures Exchange
STEM	short term energy market
STPIS	service target performance incentive scheme
STTM	short term trading market
SWIS	South West Interconnected System
TCC	total cost of constraints
TFP	total factor productivity
TJ	terajoule
TJ/d	terajoules per day
TW	terawatt
TWh	terawatt hour
URF	Utility Regulators Forum
VENCorp	Victorian Energy Networks Corporation
VTS	Victorian Transmission System
WACC	weighted average cost of capital

Australian
Competition &
Consumer
Commission

Australian Government
Department of Resources, Energy and Tourism

ENHANCING AUSTRALIA'S ECONOMIC PROSPERITY

A CLEANER FUTURE FOR POWER STATIONS

INTERDEPARTMENTAL TASK GROUP DISCUSSION PAPER

Introduction

On 23 July 2010 the Government released[1] the *Cleaner Future for Power Stations* election commitment which includes the establishment of new emissions standards and reporting requirements for power stations, and in particular that all new coal-fired power stations will be required to meet best practice emissions standards and be built Carbon Capture and Storage Ready (CCS-Ready). Specifically, the Government announced:

1. *Best practice emissions standards for new coal-fired power stations:*
    - all new coal-fired power stations will be required to meet an emission standard set with reference to best practice coal-fired generation technology;
    - the standard for best practice will be determined in consultation with stakeholders;
    - the starting point for consultation will be below the level (0.86 tCO_2-e/MWh) at which transitional assistance was proposed under the Carbon Pollution Reduction Scheme (CPRS); and
    - the standards are to commence in 2011.

2. *CCS-Ready standards:*
    - approval will only be granted to new coal-fired generators which meet the emissions standard and are capable of retrofitting CCS technologies;
    - all new coal-fired generators will be required to retrofit CCS technologies within an appropriate time after they become commercially available; and
    - the standard for CCS-Ready, tailored for Australian conditions, will be determined by the Government in consultation with stakeholders. The National CCS Council (formerly the National Low Emissions Coal Council) will play a key role in assisting with the work on the CCS-Ready standard.

3. *Expansion of Energy Efficiency Opportunities (EEO) program to cover* all existing generators, including coal-fired power stations.

4. *Publication of National Energy and Greenhouse Reporting (NGER) data:*
    - The Government will publish annual facility-level greenhouse gas emissions and electricity production data by electricity generation facility.

The Government has established an Interdepartmental Task Group (ITG) to develop these measures, in consultation with energy market institutions, State and Territory Governments, industry, and environmental stakeholders.

This discussion paper is intended to facilitate initial consultation with stakeholders on the *Cleaner Future for Power Stations* measures. It outlines the Government's commitment in relation to each of these elements, discusses the context of these measures, and proposes a way forward to defining and implementing measures. It also raises a series of important questions, for which stakeholder feedback is sought.

Written submissions to the ITG Secretariat are invited by 24 December 2010.

The ITG intends to undertake a consultation forum prior to the 24 December, and to continue consultation with stakeholders throughout the development and finalisation of these measures.

[1] Julia Gillard – speech at University of Queensland, 23 July 2010; Julia Gillard, Martin Ferguson and Penny Wong, Joint Media Release, Tough Emissions Standards for New Coal-fired Power Station, 23 Jul 2010 http://www.alp.org.au/federal-government/news/tough-emissions-standards-for-new-coal-fired-power/

Best Practice Emission Standards for New Coal- Fired Power Stations

Announced commitment

In relation to best practice emissions standards the Government announced:

- all new coal-fired generators are to meet an emission standard set with reference to best practice coal-fired generation technology;
- the standard for best practice will be determined in consultation with stakeholders;
- the starting point for consultation will be below the level (0.86 tCO_2-e/MWh); and
- the standards are to commence in 2011.

Context

Coal-fired electricity generation is critical for ensuring adequate, reliable, and affordable energy supply in Australia. Approximately three quarters of Australia's electricity is generated by coal, and just over 80 per cent of electricity generated in the National Electricity Market. This reflects the abundance of coal resources close to major electricity loads, and its competitiveness as a source of base load power generation. While there is expected to be an increase in gas and renewable generation; coal-fired electricity is likely to continue to play a major role in Australia's electricity generation requirements into the foreseeable future[2].

Currently, the electricity sector represents around 36 per cent of Australia's total greenhouse (GHG) emissions. Of this, coal-fired electricity generation accounts for 89 per cent of the electricity sector's GHG emissions[3]. The emissions-intensity of existing coal plants ranges from around 0.80 to 1.38 tCO_2-e/MWh ('as generated')[4] reflecting differences in plant age, design, and the type of coal used.

Significant progress has been made over the last two decades at improving the efficiency, and subsequent emissions-intensity of coal-fired generators. Given the long lifespan of generation assets (between 30 and 40 years), it is important that new coal-fired generators meet best practice emissions-intensity standards to reduce Australia's future GHG emissions.

Some State Governments have already implemented conditions for new coal-fired generators. The Victorian Government is developing a proposal to restrict approval of new coal-fired generators with emissions intensity above 0.80 tCO_2-e/MWh. The Queensland Government's conditions for new coal-fired generators require world's best practice low emission technology in order to achieve the lowest possible levels of emissions; and carbon capture and storage (CCS) readiness including retrofitting that technology within five years of CCS being proven on a commercial scale.

The purpose of establishing an emissions standard for new coal-fired power stations (referred to hereafter as 'the Standard') is to ensure that new investment in coal-fired generation is consistent with deployment of best practice emissions-intensity coal-fired electricity generation technology.

Most coal-fired generators in Australia (and globally) are based on combustion of pulverised coal (PC) in boilers to generate superheated steam that drives steam turbines to generate electricity. The heat and pressure of the steam determines the relative efficiency of the plant. Efficiencies vary from 20 per cent to more than 40 per cent,

[2] Geoscience Australia and ABARE, 2010, Australian Energy Resource Assessment
[3] Department of Climate Change and Energy Efficiency
[4] Unless otherwise stated emission intensity figures identified within this discussion paper are on an "as generated' basis.

depending on the thermal content of the coal used and specific design of the generation plant[5]. The emissions-intensity in PC generation varies depending on a large range of factors, including:

- type of coal used (eg, brown or black coal);
- boiler and steam turbine temperatures and pressures (subcritical, supercritical and ultra-supercritical);
- the type of plant cooling (air or water);
- design and type of generator; and
- age of the plant.

Coal is ranked in terms of moisture, carbon, and energy content. Sub-bituminous (black coal) - a low rank coal, and bituminous-thermal (black coal) - a higher ranked coal, are used for electricity generation in Queensland, New South Wales and Western Australia. The emissions-intensity of black coal-fired generation in Australia ranges from around 0.80 – 1.11 tCO_2-e/MWh ('as generated'). Lignite (brown coal) is a low rank coal, with high moisture content and low energy content. It is used for electricity generation mainly in Victoria. The emissions-intensity of brown coal-fired generation in Australia ranges from around 0.90 - 1.38 tCO_2-e/MWh ('as generated')[6]. Pre-drying brown coal has the potential to reduce carbon dioxide emissions close to a level achieved by black coal.

Co-firing is also used to generate electricity using coal with other fuel sources such as gas or biomass, the emissions-intensity of this form of generation is dependent on the proportion of gas or biomass used[7]. Electricity can also be generated as a co-product of other production processes, such as coal-to-liquids and coal-to-urea projects.

Boiler and steam turbine temperatures and pressures (referred to as subcritical, supercritical and ultrasupercritical) used in PC generation have different emissions-intensity. Subcritical generators operate at a relatively low temperature and pressure. Supercritical generators operate at a higher temperature and pressure, and are a more efficient form of electricity generation. The ultra-supercritical pulverised coal boilers can potentially increase efficiency significantly (to over 45 per cent) and reduce (by up to 40–50 per cent) CO_2-e emissions.

The type of plant-cooling also influences the emissions-intensity of electricity produced. While water cooling is less emissions-intensive than air cooling, water constraints can limit the use of water-cooled plants. While technologies can improve the energy-intensity of air-cooled plants, the overall improvement in emissions-intensity will not be as marked as for water cooled plants.

Carbon capture and storage (CCS) is a greenhouse gas mitigation technology that can potentially reduce CO_2 emissions from existing and future coal-fired power stations by more than 80 per cent. There are three main approaches to reducing emissions from coal use by removing CO_2. One of these removes CO_2 before the coal is burnt to produce electricity (i.e. pre-combustion using Integrated Gasification Combined Cycle technology) whereas the other two remove the CO_2 after combustion (oxyfuel combustion and post-combustion capture)[8].

The emissions-intensity of new entrant black coal Integrated Gasification Combined Cycle technology (IGCC) in Australia is estimated at around 0.70 tCO2-e/MWh. Integrated Drying Gasification Combined Cycle technology (IDGCC) using brown coal generates electricity at an estimated average emissions-intensity of around 0.73-0.78 tCO_2-e/MWh[9]. Advanced turbine technologies aimed at further increasing the efficiency of IDGCC, are in the research and development phase.

[5] Geoscience Australia and ABARE, 2010, Australian Energy Resource Assessment
[6] ACIL Tasman, 2009 Fuel resource, new entry and generation costs in the NEM
[7] Geoscience Australia and ABARE, 2010, Australian Energy Resource Assessment
[8] Geoscience Australia and ABARE, 2010, Australian Energy Resource Assessment
[9] Victorian Government Climate Change Action Plan 2010

IGCC CCS plants are estimated to have an emissions-intensity of 0.06 tCO_2-e/MWh. Oxyfuel combustion using black coal with CCS has an estimated emissions-intensity of 0.093 tCO_2-e/MWh[10]. While CCS technologies offer promising emissions reductions, CCS is not yet commercially available. This technology is further discussed in the subsequent chapter on "CCS-Ready Standards".

By comparison, alternative base load electricity generation from gas is estimated at 0.62 tCO_2-e/MWh from gas using Open Cycle Gas Turbines, and 0.37 tCO_2-e/MWh using Combined Cycle Gas Turbines. Accordingly, dual-fuelled power stations that generate electricity from coal-fired generation units and gas-fired generation units will have lower emissions-intensity than power stations that generate electricity from coal only.

There are differences of opinion in the estimated emissions-intensity of new power stations, being dependent on a range of factors. Indicative estimates for the emissions-intensity of new entrant and emerging technologies are depicted in the following table and graph, as a guide for discussion.

Table 1: Type, and estimated emissions-intensity of new entrant power stations

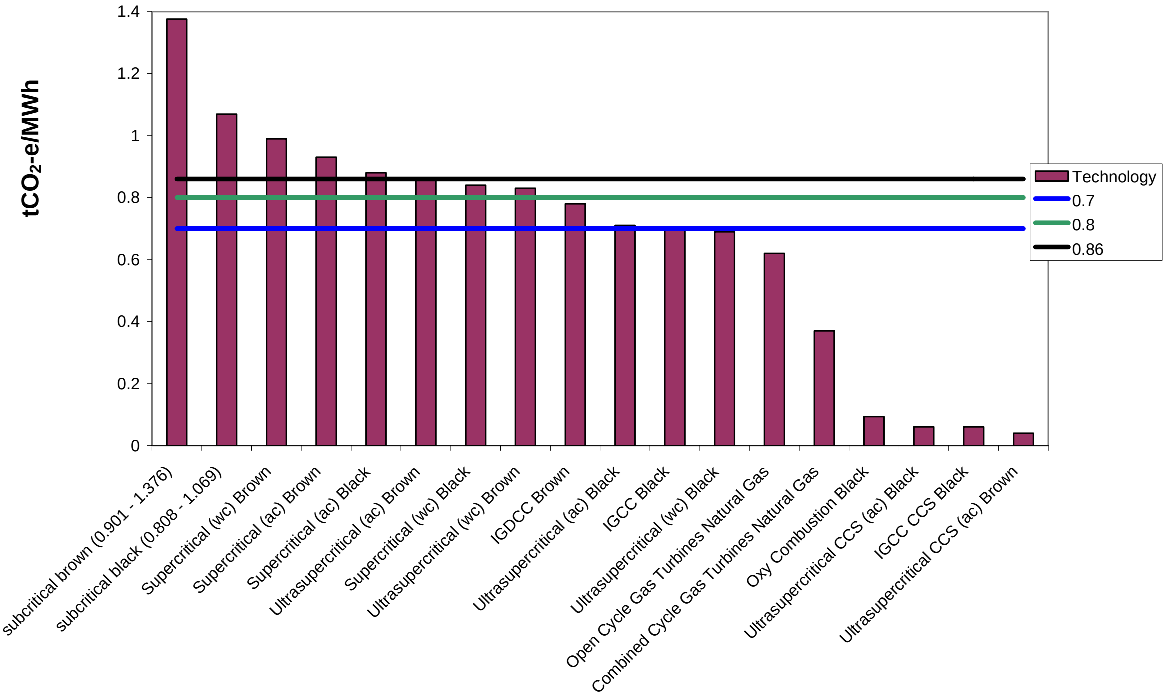
Technologies	***Fuel type***	***Estimated emissions-intensity*** **tCO_2-e/MWh** ***(as generated)***
Subcritical	Brown	0.901 - 1.376
Subcritical	Black	0.808 - 1.069
Supercritical (ac)	Brown	0.93
Supercritical (wc)	Brown	0.99
Supercritical (ac)	Black	0.88
Supercritical (wc)	Black	0.84
Emerging technologies expected emissions-intensities		
Ultrasupercritical (ac)	Brown	0.86
Ultrasupercritical (wc)	Brown	0.83
Ultrasupercritical (ac)	Black	0.71
Ultrasupercritical (wc)	Black	0.69
Emerging technologies expected emissions-intensities		
Ultrasupercritical CCS (ac)	Brown	0.04
Ultrasupercritical CCS (ac)	Black	0.06
Oxy Combustion	Black	0.093*
IGCC	Black	0.70
IGDCC	Brown	0.78**
IGCC CCS	Black	0.06
Emissions- intensity of alternate base load power plants		
Combined Cycle Gas Turbines	Natural Gas	0.37
Open Cycle Gas Turbines	Natural Gas	0.62

*Source: Derived from ACIL Tasman. *EPRI **Victorian Government Climate Change White Paper.*

ac= air cooled, wc = water cooled.

[10] EPRI Assessment of Electricity Generation Technologies in Australia 2010

Graph 1: Emissions-intensity of generation technologies



These estimates provide an indication of which technologies could be eligible under different emissions-intensity standard thresholds for new coal-fired power stations. As an example, 0.86 tCO_2-e/MWh threshold (indicated by the black line) would limit new coal-fired power stations to: best practice black coal subcritical and supercritical generation; and new technologies not currently used at commercial scale in Australia. Currently in Australia, only five subcritical and four supercritical power stations would meet this threshold. An emissions-intensity threshold set at this point would represent a significant reduction in the emissions-intensity of the next generation of coal-fired power stations.

A 0.80 tCO_2-e/MWh threshold (indicated by the green line) would limit new coal-fired plants to generators using black coal ultrasupercritical combustion technology, or emerging IGCC and IDGCC technologies which are not yet used commercially in Australia. A 0.70 tCO_2-e/MWh threshold (indicated by the blue line) would set coal-fired technology at the estimated best practice new entrant - IGCC technology.

The costs and implications of requiring best practice technologies, including capital cost, operating risk (particularly for emerging technologies, not currently used in Australia) will affect investment decisions, and the cost of electricity. It is important that consideration is given to the implications for Australia's energy mix and the capacity to provide reliable, adequate and affordable electricity to households and industry, as well as the abatement potential achieved.

Proposed way forward

The Government's announcement indicates that the Standard will be set with reference to best practice coal-fired generation technology, and at an emissions-intensity threshold below 0.86 tCO_2-e/MWh. This threshold was based on the *Carbon Pollution Reduction Scheme* 'as generated' threshold for *Electricity Sector Adjustment Scheme* assistance. In terms of setting the emissions-intensity threshold, the ITG intends to continue to use an 'as generated' standard, rather than 'sent out'.

The Standard could be set at different thresholds or take different forms, for example:

1. **At or below 0.86 tCO_2-e/MWh**

2. **At or below 0.80 tCO_2-e/MWh**

3. **At or below 0.70 tCO_2-e/MWh**

4. **A differentiated threshold by best-in-class existing and emerging systems i.e. subcritical, supercritical; ultrasupercritical, IGCC, and IDGCC;** or

5. **A Standard set with review and possibility of a declining threshold to account for improvements in technology.**

The Government seeks stakeholder views on the range of thresholds provided above, including any reasons for a preferred standard, with a view to the Government analysing this suite of options, and the implications and benefits associated. This will include analysis on the ability to retrofit certain types of plant to carbon capture and storage (CCS) technologies (see subsequent CCS-Ready section).

Coverage

In accordance with the announcement of the *Cleaner Future for Power Stations* commitment, the Standard will cover '*all new coal-fired power stations'*. A new coal-fired power station could be defined as

"A generation complex, generation complex project or generation unit that uses coal to generate electricity and may be grid connected or non-grid connected generation"

The announcement of the *Cleaner Future for Power Stations* commitment stated that the new requirements will not impact upon existing plants. However, the Standard may cover expansion of plant units. Applying the Standard to significant expansion of units would level out investment opportunities in Greenfield, and Brownfield generation, and provide for emissions-intensity improvements in existing generation assets. However, there is a risk that this could discourage capacity expansions. There are three options in relation to coverage of the Standard:

1. exclude existing generators, including future expansion generation units;
2. exclude existing generation units; and exclude expansion units if they are of a lower emissions intensity than the existing generation units; or
3. exclude existing generation units; however apply the standard to new expansion units.

The Standard would not apply to maintenance and refurbishment of existing generation units. The ITG seeks stakeholder views on the coverage of the Standard.

The announcement of the *Cleaner Future for Power Stations* commitment stated that '*planned investments which already have environmental approvals, and are determined by the energy market institutions as being sufficiently advanced in their regulatory approvals at commencement of these standards, will be exempt from them'*. In this regard, the Standard may not apply to 'advanced' or 'committed' projects. A 'committed project' could mean a project which energy market institutions considers has been fully committed by the project proponent taking into account the following factors:

a) the project proponent's rights to land for the construction of the project;
b) whether contracts for the supply and construction of the project's major plant or equipment, including contract provisions for project cancellation payments, have been executed;

c) the status of all planning and construction approvals and licences necessary for the commencement of construction of the project, including completed and approved environmental impact statements;

d) the level of commitment to financing arrangements for the project; and

e) whether project construction has commenced or a firm date has been set for it to commence.

An 'advanced proposal' could be considered as any project that meets at least three, and shows progress on two, of the five criteria specified for a committed project.

The ITG seeks stakeholder views on the most transparent and efficient process for determining inclusion; the level of detail required to provide certainty to investors; and, appropriate criteria to inform energy market institution assessment.

Date of Commencement

The announcement of the *Cleaner Future for Power Stations* indicated that the standards would commence in 2011. There are a number of options for the date when the Standard could come into effect, such as:

- Date of Royal Assent 2011; or
- 31 December 2011.

The ITG acknowledges that the date of commencement may affect coverage of individual plants, and seeks stakeholder views on the impact of the commencement date and how to best provide certainty to investors.

Implementation and Administration

Legal form

Given the Standard places a requirement for emissions-intensity thresholds to be met, with implications for the approval process, it will be necessary to enact the Standard through legislation. There are two likely ways in which the Standard could be enacted:

- a stand alone Act of Parliament incorporating the Standard, and CCS-Ready requirements; or
- insertion of a trigger in existing legislation, for example relevant State or relevant electricity market legislation.

Stand alone legislation is likely to provide a more expeditious and transparent form of enacting the Standard, and subsequent modification over time, if required. The Government seeks stakeholder views on the legal form of this legislation.

Administration

The Standard will require a form of administrative regime and an Authority to receive, and assess applications, make approval decisions, and monitor performance. The application process is likely to be on the basis of an independent expert technical report which estimates the predicted performance of the generator over a 2 year introductory period. The appropriate Authority could take a range of forms including:

- a existing national regulator;
- a new national regulator or body;
- Commonwealth Minister;

- State-based approvals bodies with an existing role in power station approvals (such as the Environmental Protection Agencies, the State regulators, or State planning authorities)

In designing an appropriate administration regime, the Government seeks stakeholder views on any administration issues, including issues which can impact project costs and development milestones, including: appropriate timing for applications and approvals; requirements for level of detail; and, appropriate criteria for independent assessors.

Monitoring and Compliance

While a plant may be deemed capable of meeting the threshold for approval, the plant performance may change over time due to under-performing assets, changes in fuel quality, the age of the plant, and changes in its performance over time. Administration of the Standard may require ongoing monitoring and compliance to ensure coal-fired plants are meeting the Standard.

Stakeholder views are sought on the form of an appropriate compliance and monitoring regime, and whether a form of penalty should apply to plants that operate at a level in excess of the Standard.

Phase Out

The Government's announcement of the Standard indicated that it would consider phasing out the new requirements upon the introduction of an economy-wide carbon price. The ITG seeks stakeholder views on any implications of a phase-out on investment, construction and planning activities. The ITG also seeks stakeholder views on an appropriate time frame to review the Standard.

KEY QUESTIONS FOR STAKEHOLDERS

Stakeholder views are welcomed on all aspects of this discussion paper, and in particular the following:

1. What are your views on the form of the standard?
2. What is the most appropriate threshold, given the implications associated with the range of options canvassed in this discussion paper?
3. Is the definition of the Standard appropriate?
4. Is the proposed coverage of the standard appropriate, particular in relation to existing power stations and advanced projects?
5. What is the most appropriate commencement date for the standard, and what are the implications for specific projects?
6. What criteria should be applied to the Authority and administration regime to minimise the costs and impacts on projects, whilst ensuring effective administration?
7. Should the standard be enforced though ongoing compliance or should approval for new coal-fired power stations be granted at commencement only?
8. Should the standard be phased out with the introduction of a carbon price, and what would be the implications of this for planning, investment, and construction activities?
9. Should the Standard be reviewed in the future?

CCS-Ready Standards

Announced commitment

In relation to CCS-Ready standards the Government announced:

- approval will only be granted to new coal-fired generators which are capable of retrofitting CCS technologies;
- all new coal-fired generators will be required to retrofit CCS technologies within an appropriate time after they become commercially available; and
- the standard for CCS-Ready, tailored for Australian conditions, will be determined by the Government in consultation with stakeholders. The National CCS Council (formerly the National Low Emissions Coal Council) will play a key role in assisting with the work on the CCS-Ready standard.

The development of a CCS-Ready Standard will give full consideration to both current state government policies and international work/developments.

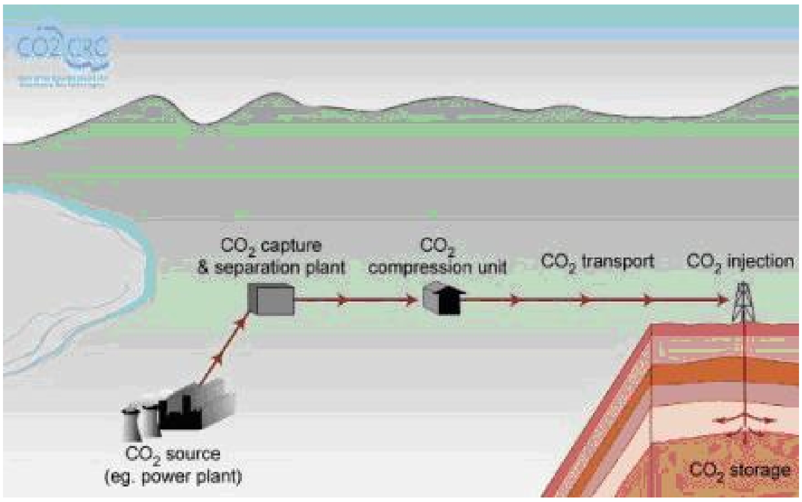
Context

Studies such as the International Panel on Climate Change (IPCC) Fourth Assessment Report (2007), the Stern Report (2006) and the International Energy Agency's (IEA) annual World Energy Outlooks have stated that the development and deployment of CCS technologies across all major emitting economies can make a significant contribution to the reduction of global GHG emissions. Furthermore, according to the IEA's Energy Technology Perspectives, CCS will need to contribute approximately one fifth of the emissions reductions necessary to reduce global greenhouse gas emissions (GHG) emissions by 50 per cent by 2050.[11] In the absence of CCS, the annual cost of meeting this emissions reduction target is approximately 70 per cent higher**.**[12]

As described in the preceding chapter on "Emission Standards", given Australia's abundant fossil fuel resources, CCS technologies have the potential to significantly reduce GHG emissions from the extraction, processing and use of these energy sources. Bringing forward broad scale deployment of CCS in Australia could help to achieve Australia's emissions reduction targets at least cost.

CCS involves the combined processes of capture, transport and geological storage of CO_2 and/or other greenhouse gases as shown in the diagram below.

[11] IEA (2008) *Energy Technology Perspectives*, Paris
[12] Intergovernmental Panel on Climate Change (IPCC) (2005) *Special Report on Carbon Dioxide Capture and Storage*, Cambridge University Press. Metz B, Davidson O, De Coninck H, Loos M and Meyer L

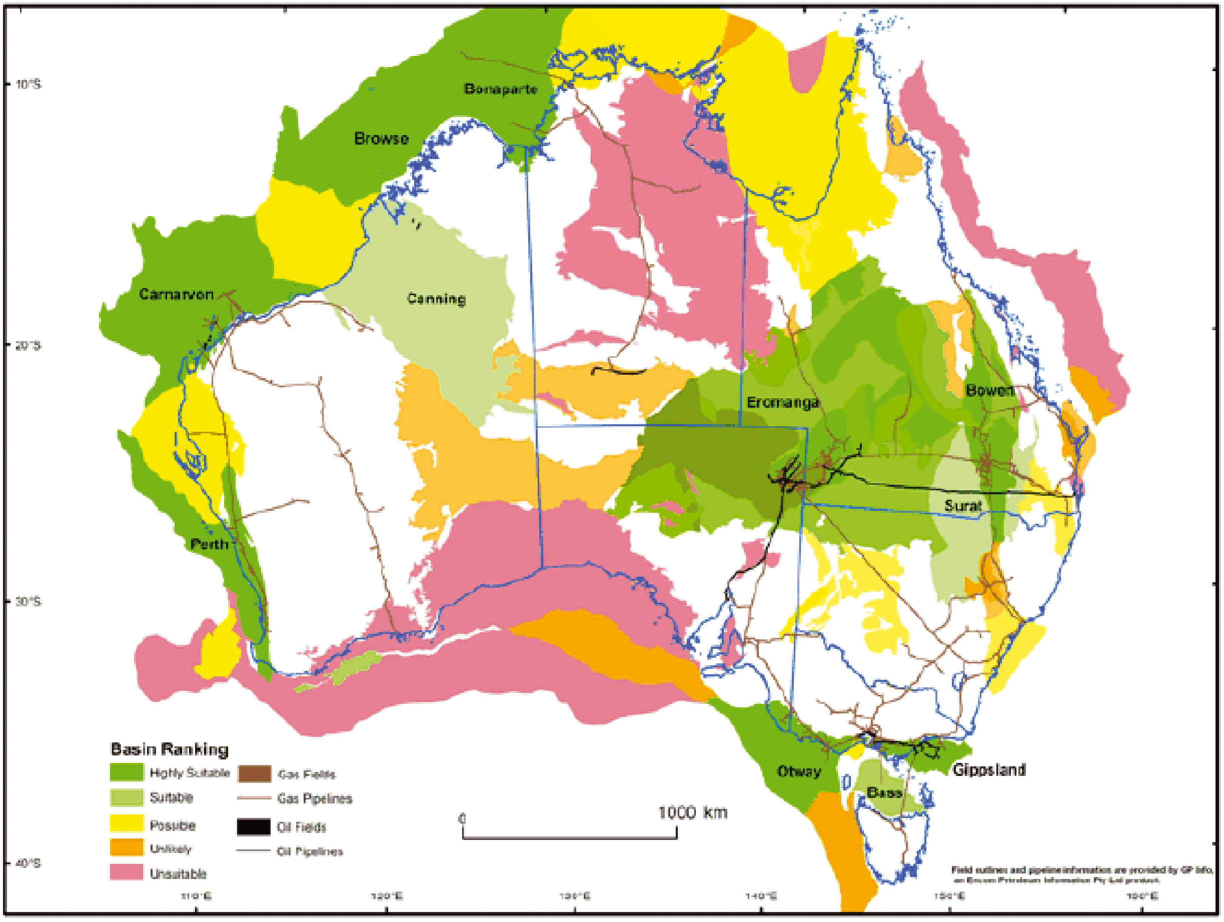


Source: CO2CRC

CO_2, a major greenhouse gas may be produced by the combustion of fossil fuels, or co-produced as a result of oil and gas extraction or some industrial processes. Instead of allowing CO_2 to be released into the atmosphere, they are captured at the emission site where they are separated from other substances. The separated stream is then compressed into a concentrated volume and transported from the source location (emission site) to the injection location. Geological storage comprises:

- the injection of the compressed CO_2 into geological formations in the deep sub-surface;
- its migration away from the immediate vicinity of the injection point; and
- its subsequent trapping in geological formations.

A figure ranking Australia's potential CO_2 storage basins is shown in the figure below.



Source: Carbon Storage Taskforce (2009)

Captured CO_2 can also be used in several industrial processes and is commonly referred to as CO_2 Use. Examples of these industrial processes are: mineralisation (carbonation); pharmaceutical and chemical processing; agriculture; and other biological applications.[13] As these processes do not consume large amounts of CO_2, they will need to be used in conjunction with permanent storage.

To capture the CO_2 before it can be emitted into the atmosphere, the CO_2 must first be separated from other gases and particulates resulting from combustion or processing. It is then compressed and purified to make it easier to transport and store. Some gas streams resulting from industrial processes, such as natural-gas purification and ammonia production, are very pure to begin with, whilst others may not be.

The three major technology options, as identified in the preceding chapter, that are available for the capture of CO_2 are:

- Post-combustion systems, which separate CO_2 from the flue gases produced by combustion of a primary fuel (coal, natural gas, oil or biomass) in air;

[13] Major Economies Forum on Energy and Climate (2009), *Technology Action Plan: Carbon Capture, Use and Storage*, Prepared by Australia and the United Kingdom in consultation with MEF Partners, p 26.

- Oxy-fuel combustion, which uses oxygen instead of air for combustion, producing a flue gas that is mainly H_2O and CO_2 and which is readily captured. This is an option still under development; and
- Pre-combustion systems, which involve processing the primary fuel in a reactor to produce separate streams of CO_2 for storage and H_2 which is used as a fuel.

Successful demonstration of CO_2 capture technologies open the way for large-scale production of low-carbon electricity and fuels for transportation, as well as for small-scale or distributed applications. Further, the IPCC indicates that the environmental risks of capture are generally considered low and can be largely governed by existing regulatory processes.[14]

The energy required to operate CO_2 capture systems reduces the overall efficiency of power generation or other processes, leading to increased fuel requirements relative to the same type of base plant without capture. However, as more efficient plants with capture become available and replace many of the older less efficient plants now in service, these impacts will be reduced.

CCS-Ready facilitates the transition to CCS and reduces the potential for stranded assets after CCS becomes commercially viable. The Global CCS Institute defines a stranded asset as a plant that is shut down before the end of its planned operational lifetime, as it is uneconomic to retrofit CCS.[15]

International developments

In 2008, the G8 Energy Ministers endorsed recommendations from the IEA and the Carbon Sequestration Leadership Forum (CSLF) that "further work [was] required to understand and define the concept of 'capture and storage ready' plants and its value as a viable [climate change] mitigation strategy." Since then, the Department of Resources, Energy and Tourism (DRET) has been part of a process with the Global CCS Institute, the IEA, the CSLF and a number of other countries to develop a globally recognised definition for CCS-Ready. This work was included in the June 2010 IEA and CSLF report to the G8.[16]

Defining CCS-Ready – Work Commissioned by the International Energy Agency, Carbon Sequestration Leadership Forum and the Global CCS Institute

The globally recognised definition contains several essential requirements to be met before a facility can be considered CCS-Ready. Essentially the project developer should:

- carry out a site specific study in sufficient engineering detail to ensure the plant is technically capable of being fully retrofitted for CO_2 capture, using one or more choices of technology which are proven or whose performance can be reliably estimated as being suitable;
- demonstrate that retrofitted capture equipment can be connected to the existing equipment effectively and without an excessive outage period and that there will be sufficient space available to construct and safely operate additional capture and compression facilities;
- identify realistic pipeline or other route(s) to storage of carbon dioxide;
- identify one or more potential storage areas which have been appropriately assessed and found likely to be suitable for safe geological storage of projected full lifetime volumes and rates of captured CO_2;

[14] Intergovernmental Panel on Climate Change (IPCC) *Special Report on Carbon Dioxide Capture and Storage*, Cambridge University Press. Metz B, Davidson O, De Coninck H, Loos M and Meyer , p 107.
[15] Global CCS Institute (2010) *CCS Ready – Issues Brief,* no.1. Available at: http://new.globalccsinstitute.com/community/groups/ccs-policy-and-regulations
[16] See IEA Papers (2010) *IEA/CSLF Report to the Muskoka 2010 G8 Summit*, 'CCS: Progress and Next Steps'. Available at: http://www.iea.org/papers/2010/ccs_g8.pdf

- identify other known factors, including any additional water requirements that could prevent installation and operation of CO_2 capture, transport and storage, and identify credible ways in which they could be overcome;
- estimate the likely costs of retrofitting capture, transport and storage;
- engage in appropriate public engagement and consideration of health, safety and environmental issues; and
- review CCS-Ready status and report on it periodically.

In considering principles of the CCS-Ready framework it is acknowledged that a degree of flexibility in the way jurisdictions apply the definition is essential, to take account of region and site specific issues and the rapidly-changing technology, policy and regulatory background to CCS and CCS-Ready globally.

The Global CCS Institute, IEA and CSLF definition applies to all industrial applications including power generation. For example, the United Kingdom's 'Carbon Capture Ready' policy extends to all combustion power plants including gas-fired power stations. The Australian Government is proposing to apply CCS-Ready only to new coal-fired power generation given its large contribution to overall national emissions. In the future, it may be appropriate to widen the scope of the CCS-Ready standard to encompass other sectors that contribute significantly to national emissions.

More recently, the Global CCS Institute released an issues paper to provide updated advice to governments wishing to implement CCS-Ready policy.[17] The paper builds upon the previous international work in this area.

State Government CCS-Ready policies

Three state governments: Queensland, New South Wales (NSW) and Western Australia (WA) have considered and/or implemented CCS-Ready policies in their respective jurisdictions. It is proposed that a national approach be taken to CCS-Ready to harmonise these policies.

Queensland

On 20 August 2009, the Queensland government announced a new commitment through its *ClimateSmart 2050* policy restricting the approval of new coal-fired power stations unless certain requirements were met.[18] The policy requires that a new power station:

- uses the world's best practice low emission technologies;
- is CCS-Ready; and
- will retrofit that technology within five years of CCS technology being proven on a commercial scale.

The Queensland government's definition of CCS-Ready requires generators to demonstrate that new plants have been designed with plans and milestones for incorporation of operational CCS and that there are no known barriers to installation once the technology has been proven on a commercial scale.

To some extent this policy was achieved through the amendment to the *Electricity Act 1994* (Qld) which requires that all new power stations obtain a Generation Authority issued by the Regulator. In deciding whether to grant the Generation Authority, the Regulator must consider, among other things:

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[17] Global CCS Institute (2010) *CCS Ready – Issues Brief,* no.1. Available at: http://new.globalccsinstitute.com/community/groups/ccs-policy-and-regulations

[18] See Department of Employment, Economic Development and Innovation, 'Conditions for new coal-fired electricity generation'. Available at: http://www.climatechange.qld.gov.au/pdf/factsheets/1energy-n4.pdf

- the objectives of the Electricity Act; and
- "relevant government policies about environmental and energy issues and the likely environmental effects of building and operating the generating plant."[19]

CCS requirements will be one of the relevant government policies to be considered by the Regulator in determining whether to grant the Generation Authority.

New South Wales

The 2007 Inquiry into Electricity Supply in NSW (the Owen Inquiry) first considered the issue of CCS-Ready.

CCS-Ready has not been legislated in NSW; however, the Director-General of the NSW Department of Planning has the ability to set requirements for an Environmental Assessment under section 75F of the *Environmental Planning and Assessment Act 1979* (NSW). This ability of the Director-General has led to Environmental Assessments considering CCS in numerous cases including the Bayswater B Power Station application. The NSW Minister for Planning has granted concept approval for the Bayswater B power station project.

In the Bayswater matter, the Director-General's Requirements prescribed that an assessment must be undertaken on key issues including greenhouse gases. The evaluation needed to include "the availability and feasibility of measures to reduce and/or offset the greenhouse emissions of the project including options for carbon capture and storage."[20] The requirement went on to say that "where current available mitigation technology is not technically or economically feasible, the Environmental Assessment must demonstrate that the proposal will use the best available technology, including carbon capture readiness and identify options for triggers that would require a staged implementation of emerging mitigation technologies."[21]

Western Australia

The application of CCS-Ready requirements by the WA Government is similar to that of NSW. CCS-Ready requirements are not found in legislation; rather the requirements have been implemented through conditions recommended by the WA Environmental Protection Authority (EPA).

For example in March 2010, the EPA recommended to the Minister for Environment that the proposed Griffin Power Bluewaters coal-fired power station expansion only be approved if it was CCS-Ready, i.e. if it was retrofitted for CCS when the EPA determined that CCS is economically and technically proven, and at least equivalent to benchmarked best practice for greenhouse gas intensity. The EPA further recommended that these requirements remain in place until the EPA determined that they were no longer complementary with a Commonwealth emissions trading system. The Minister has followed the EPA's recommendations.

Proposed way forward

It is proposed that the most relevant principles from the international definition be adopted by Australia as mandatory requirements that a new power station must meet to satisfy being classed as a CCS-Ready facility.

Six proposed mandatory requirements consider issues pertaining to the retrofit of CCS which will avert the future risk of a 'stranded asset'. The requirements are:

1. Demonstrate sufficient space and access on site and within the facility to accommodate carbon capture and compression facilities for the majority of the plant's CO_2 emissions;

[19] See section 180(5) of the *Electricity Act 1994* (Qld).
[20] http://majorprojects.planning.nsw.gov.au/files/37092/Director-General's%20Requirements.pdf
[21] Ibid.

- *Proponents will submit a site plan that satisfactorily details the footprint of the CCS equipment needed (i.e. CO_2 compression and capture equipment, chemical storage facilities) to capture the majority of the plant's CO_2 emissions. The site plan must allow sufficient space, as determined by design studies, for needed equipment, construction zone and the effective handling of environmental and safety issues.*

2. Identify potential areas for long term geological storage of captured CO_2 (meeting the plant's capture needs);

- *Proponents will estimate the total CO_2 to be captured for the plant's life and identify geological formations that could realistically store this amount. A storage assessment will evaluate the formations based on pre-competitive data, such as work completed by state governments, the Australian Government and the Carbon Storage Taskforce. Proponents are not required to obtain a permit for these areas until CCS must be retrofitted. A risk assessment must be included, including key environmental considerations, such as post-injection CO_2 leakage and land use conflicts in the proposed basins, based on the information utilised in the storage evaluation.*

- *Where a project developer proposes to use an option other than geological storage of CO_2 to dispose of part of the captured CO_2, the proponents must identify the proportion of CO_2 expected to be disposed of by an alternative method and the site requirements and timeline for the conversion process plant. The Government may consider developments in emerging technologies in the future, and reassess the proportion of captured CO_2 that may be disposed of by alternative methods.*

3. Undertake a site specific assessment into the technical and economic feasibility of the CO_2 capture retrofit using one or more technology choices;

- *Proponents will identify an appropriate capture technology and prepare a feasibility study on retrofitting this technology into the plant's design. This must include an economic analysis of capture implementation and identify environmental and safety approvals required. Proponents are not required to obtain these approvals until CCS must be retrofitted.*

4. Identify a realistic transport method to identified storage sites;

- *Proponents will identify a transport method technically capable of transporting the total CO_2 to be captured for the plant's life. Proponents must include an assessment addressing land use conflicts and environmental and safety approvals. However these approvals are not required to be obtained until CCS must be retrofitted.*

5. Demonstrate measures and approvals that deal with the collection and treatment of pollutants resulting from the capture process and provisions for increased water requirements; and

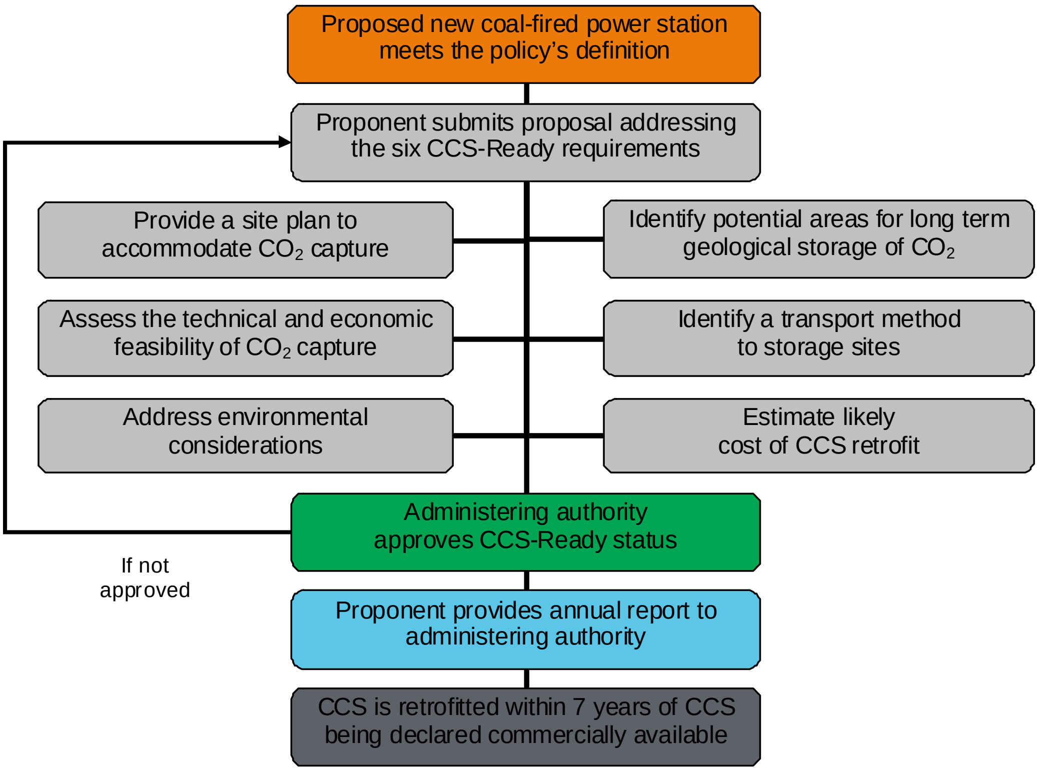
- *Proponents will address further environmental considerations by providing an environmental impact statement. This must outline measures that will be taken to manage chemical wastes and increased water use including any environmental or safety approvals required. Proponents are not required to obtain these approvals until CCS must be retrofitted.*

6. Estimate the likely costs of retrofitting capture, transport and storage.

- *Proponents will provide a detailed economic feasibility study of retrofitting CCS.*

Although all of the requirements must be applied, item 6 is classed as the key requirement.

A flow chart of the process is included below:



Coverage

It is proposed that the CCS-Ready standard should apply to all new coal-fired generators as referenced in the preceding chapter.

Implementation and administration

Legal form

It is proposed that the CCS-Ready standard could be implemented through the same instrument as the best practice emissions standards, to ensure consistent application and streamlined processes.

There are a number of ways in which the standards could be enacted, as referenced in the preceding chapter.

Administration

It is proposed that the CCS-Ready standard could be implemented through the same process as the best practice emissions standards, to ensure consistent application and streamlined processes.

There are a number of ways in which the standards could be administered, as referenced in the preceding chapter.

Reporting

Proponents will provide an annual report to the administering Authority on the plant's compliance with the standards, ensuring that the Authority is aware of any change in circumstance that affects the CCS-Readiness of the plant. Proponents must respond to developments in CCS and update feasibility assessments accordingly.

How will CCS be assessed as commercially available?

Several demonstration projects are planned in Australia as there are currently no plants operating at a level sufficient to demonstrate that the integrated technology is effective at scale. CCS is in a similar situation worldwide.

New coal-fired generators covered by the CCS-Ready standard will be required to retrofit CCS technologies within an appropriate timeframe after they become commercially available. A commitment of this nature requires a trigger point to define when CCS is considered commercially available and a defined appropriate time for retrofit.

To determine whether CCS is considered commercially available the Australian Government, in consultation with bodies such as the Global CCS Institute and IEA, would undertake a review process every two years. The review would consider:

- the technical viability of CCS, and whether retrofitting a plant is both operable from an engineering perspective and of a comparable scale (an indicative scale-up will be advised at a future date);
- the operational viability of each element of the technology in conjunction with other elements (i.e. carbon capture along with CO_2 transport and storage); and
- Australia-specific factors affecting the commercial availability of CCS.

Further, the Australian Government would define commercial availability as:

- integration of carbon capture, transport and storage has been proven at a comparable scale and technology in several demonstration plants worldwide;
- the systems comprising CCS are readily attainable; and
- safety and environmental risks of CCS have been minimised (e.g. the potential for carbon leakage from storage sites).

If the report positively assesses that CCS is commercially available, the Minister for Resources and Energy may make a declaration that a retrofit must occur. Due to the costs and planning involved with CCS being retrofitted to power generators, it is proposed that it will be mandatory to implement the planned CCS retrofit within four years and complete the retrofit within seven years of it being declared. This may allow the CCS retrofit to be implemented in a graduated manner.

KEY QUESTIONS FOR STAKEHOLDERS

Stakeholder views are welcomed on all aspects of this discussion paper, in particular the following:

10. Are there exceptions where it is not appropriate for the CCS-Ready standard to apply to the same activities and entities as the best practice emissions standards?
11. Are there reasons to enact the CCS-Ready standard through a different legislative process than the emissions standards? If so, what alternative would be suggested?
12. Are there reasons to administer the CCS-Ready standard through a different Authority or process than the emissions standards? If so what alternative would be suggested?
13. What criteria need to be covered in regulation or guidance material on what CCS-Ready facilities may require to demonstrate their CCS readiness?
14. What level of detail, if any, is required or practical when assessing whether a plant is CCS-Ready?
15. Should proponents be required to secure rights to potential storage areas to meet the CCS-Ready criteria?
16. Could the definitions create any unintended incentives, inconsistent with minimising long term emissions?
17. Is annual reporting appropriate to ensure that new power plants continue to comply with CCS-Ready standards?
18. Is it appropriate to phase out the CCS-Ready standard once a carbon price is introduced?
19. What level of detail should be required in the economic feasibility study?

The Extension of the Energy Efficiency Opportunities Program inclusion of electricity Generators

Announced commitment

In its announcement the Government also stated that it would:

- extend the Energy Efficiency Opportunities (EEO) program to all existing generators, including coal-fired power stations.

Context

Energy Efficiency Opportunities (EEO) program is designed to improve identification and uptake of cost-effective energy efficiency opportunities and thereby improve business productivity and reduce greenhouse gas emissions. Participation of generators in EEO will enable public recognition of the focus the energy supply sector already has on energy efficiency, and the rigorous and comprehensive assessment requirements will assist companies in the sector to identify new cost effective ways to improve efficiency.

The EEO program is enabled by the *Energy Efficiency Opportunities Act 2006* and the Energy Efficiency Opportunities Regulations 2006. It requires large energy-using businesses to carry out rigorous and comprehensive assessments to identify and evaluate cost effective energy efficiency opportunities, and report publicly on the results. Decisions on which energy efficiency opportunities to implement are made at the discretion of the business, but these decisions will be under public scrutiny through the public reporting requirement.

The Energy Efficiency Opportunities (EEO) program is mandatory for corporations in Australia that use more than 0.5 petajoules (PJ) of energy per year. There were over 280 controlling corporations registered for the EEO program as at October 2010.

Currently, corporations engaged mainly in electricity generation are temporarily exempt from obligations under the EEO legislation (until 30 June 2013). Electricity generators that operate non exempt activities (such as coal mining or gas production) that use more than 0.5 PJ of energy per annum are; however, not exempt for those activities and must register for the program and are required to undertake energy efficiency assessments.

The EEO program is designed to accommodate a wide range of business circumstances, so that it can be integrated into normal business processes and become an effective tool for assisting participants to improve their energy efficiency. While EEO is a legislative requirement, companies undertaking assessments to date have found significant energy and financial savings that are delivering genuine business benefits. In May 2010 the Department of Resources, Energy and Tourism published *First Opportunities A Look at Results from 2006 - 2008* which reports the outcomes from the first two years action by participants under the EEO program. This report is available on the Department's website at:

http://www.energyefficiencyopportunities.gov.au

On 4 November 2010 the Minister for Resources and Energy announced the latest results from action under the EEO Program. Details are contained within the '*Continuing Opportunities – A Look at Results for the Energy Efficiency Opportunities Program 2006-2009'*. 199 companies with trigger years 2005-06 and 2006-07 reported at the end of 2009 on progress over the first three years of the program. They reported that they had assessed 82 per cent of their energy use. From these assessments they had identified energy efficiency opportunities with annual savings of 113.7 petajoules (PJ) or 8.3 percent of energy use assessed. These potential savings are worth a net annual benefit of over $1 billion, and the Government estimates this will save 8.9 million tonnes of CO2 equivalent or 1.5 percent of Australia's 2007-08 total emissions if implemented. 93 PJ of these opportunities have a better than 4 year payback.

From these identified opportunities companies reported they were committed to implementing annual energy savings of 61.5 PJ, or 54 percent of the identified savings. This is worth more than $650 million pa in net financial benefits, saving an estimated 5.4 million tonnes of CO2 equivalent pa or 1 percent of Australia's 2007-08 total emissions. 60.3 percent of savings with a payback of better than 4 years are being adopted by companies.

Companies' implementation commitments for savings with a better than four year payback rose 64 percent from 34.1 PJ to 56 PJ of annual savings from 2008 to 2009.

Savings to be implemented represent an average net abatement saving of approximately $110 per tonne of CO2 reduced. This means that companies are getting a large financial return, not a cost, for saving greenhouse emissions from their energy efficiency opportunities.

Another 32 percent of opportunities (36.1 PJ) were under further investigation and 14 percent (15.8 PJ) were not to be implemented at the reporting date. This report, '*Continuing Opportunities – A Look at Results for the Energy Efficiency Opportunities Program 2006-2009',* is also available on the Department's website at:

http://www.energyefficiencyopportunities.gov.au

Efficiency improvements for electricity generators have previously been encouraged through programs including the Generator Efficiency Standards and Greenhouse Challenge programs. The Generator Efficiency Standards program ceased in 2009.

Generation businesses may have obligations under state based programs such as the Victorian Energy and Resource Efficiency Program, the Queensland State Energy Savings Program and the New South Wales Energy Savings Action Plan program. Many corporations with generation activities already report under the National Greenhouse and Energy Reporting System (NGERS) administered by the Department of Climate Change and Energy Efficiency.

The EEO Program is committed to working with other Commonwealth and state based agencies to minimise the burden of duplicative obligations across programs. Substantial progress has been made in aligning reporting requirements with the NGERS Scheme through the OSCAR online reporting system. This work is ongoing in accordance with the COAG National Greenhouse and Energy Reporting Streamlining Protocol.

Proposed way forward

Coverage

Participation in the EEO Program is determined by corporate group energy use. Generation corporations with operational control of energy use across their corporate group exceeding 0.5 PJ would be required to register and participate in the program. Corporate responsibility for energy use under EEO is aligned with the operational control definition of responsibility under NGERS. Energy sources applicable for determining energy use of a corporate group are listed in Schedule 1 of the *National Greenhouse and Energy Reporting Regulations 2008* http://www.climatechange.gov.au/en/government/initiatives/national-greenhouse-energy-reporting.aspx

Expansion of the EEO Program to the electricity generators is estimated to result in the registration of approximately three dozen additional corporate groups.

The EEO extension is intended to apply to generators from 1 July 2011.

Implementation and Administration

Legal form

The current exemption for electricity generation is effected by regulation under the *Energy Efficiency Opportunities Act 2006.* it is proposed that this regulation be amended to remove the exemption. Generators that meet the EEO registration requirements (described below) would then be subject to EEO obligations.

Administration

The EEO program operates on a rolling five-year assessment cycle. There are a number of obligations spaced across the EEO 5 year assessment cycle.

http://www.ret.gov.au/energy/efficiency/eeo/industry_guidelines/Pages/default.aspx

Registration

Corporations have 9 months from 1 July to apply to register for the program if their corporate group's energy use exceeded 0.5 petajoules in the trigger year – the preceding financial year, which is intended to be 2010-11 for generators. This would mean a registration deadline of 30 March 2012.

Assessment and Reporting Schedule

Registered corporations are then required to submit an Assessment and Reporting Schedule by 31 December – 18 months following the end of the trigger year. The Assessment and Reporting Schedule provides information to the government about baseline energy use and corporate structure and sets out a plan of how the corporate group will carry out the required assessments to address the key elements of the Assessment Framework.

Assessments

Businesses registered under EEO are required to undertake detailed assessments to the regulated standard in order to identify cost-effective opportunities to improve the efficiency of their energy use, with a financial payback of up to four years. Under the program, participating corporations must assess a minimum of 80 percent of their baseline corporate energy use during the first five year cycle. In addition all sites that use more than 0.5 PJ must be assessed. Second and subsequent assessment cycles require a minimum of 90 percent of corporate energy use to be assessed over five years

Each member of the corporate group scheduled to carry out assessments must complete its first assessments of at least one site, key activity or business unit within the first two years of the assessment cycle – ie by 30 June 2013.

Reporting

The first annual public report, and the first report to Government, are due by 31 December – 30 months after the end of the trigger year, Public reports are then required annually, The outcomes of assessments are reported both publicly and to the Government. Reports focus on the energy savings opportunities identified in the assessment/s and the business response to those opportunities, and later reports update the previous ones – i.e. reports are cumulative.

The Assessment Framework

The program's Assessment Framework takes a whole of business approach to assessing energy use and energy savings opportunities, rather than a narrow energy audit approach. The framework requires corporations to look at the many factors influencing energy use, including leadership, management and policy; the accuracy and quality of the data and analysis; the skills and perspectives of a wide range of people; decision making; and communication of assessment outcomes. Participants are expected to meet minimum requirements in each of these areas.

The Assessment Framework is set out in the Energy Efficiency Opportunities Regulations 2006. The Assessment requirements were developed by building on the Australian/New Zealand Energy Audit Standard (3598:2000), drawing on experience from businesses and extensive industry consultation.

The Assessment Framework is made up of six key elements:

- Leadership support for the assessment and the improvement of energy use.
- The involvement of a range of skilled and experienced people, and people with a direct and indirect influence on energy use during the assessment process.
- Information and data that is appropriately, comprehensively and accurately measured and analysed.
- A process to identify, investigate and evaluate energy efficiency opportunities with paybacks of four years or less.
- Business decision making and planning for opportunities that are to be implemented or investigated further.
- Communicating the outcomes of the assessment and the investment decisions made regarding the opportunities identified and proposed business response, to senior management, the board and personnel involved.

Further detailed information on the EEO Assessment Framework and all program requirements are available in the Energy Efficiency Opportunities Industry Guidelines and NGERS Supplement:

http://www.ret.gov.au/energy/efficiency/eeo/industry_guidelines/Pages/default.aspx

Capacity Building

The EEO Program has published a series of materials to assist participating companies and the energy services sector meet the Program's requirements. The EEO Program places a large emphasis on communicating with participants to ensure that they are aware of the Program's requirements, and have access to tools and publications that will assist them. A range of guidance, case studies and technical materials have been developed and published.

The Department communicates with EEO Program stakeholders primarily through Client Liaison Officers, who each work with a group of companies in a particular industry to help them meet their compliance obligations. Other methods of communication include: the EEO website www.energyefficiencyopportunities.gov.au; quarterly e-newsletters; targeted emails and mail-outs; and a dedicated EEO Hotline.

Each year the Department organises national workshops to provide participants with information about how to meet Program requirements and achieve better results.

Compliance and Verification

The EEO legislation provides for fines of up to $110,000 per offence for non-compliance.

The program takes an approach through its capacity building efforts of assisting corporations to comply, and expects a constructive and cooperative approach from participants. However penalties will be pursued if corporations persist with wilful non compliance.

The Department undertakes verification activities, both desktop and on-site visits, to identify non-compliance. Around 100 corporations a year participate in desktop verification with 20-30 corporations a year being subject to full verification including site visits.

KEY QUESTIONS FOR STAKEHOLDERS

Stakeholder views are welcomed on all aspects of this discussion paper, in particular the following:

20. Are there particular EEO requirements that would be very difficult to apply to electricity generators?

21. Are there particular areas of the requirements where specific guidance for electricity generators is needed?

22. Are there any further changes needed to ensure the requirements deliver on the intent of the Act with regard to generators? For example, learnings from participation in the Generator Efficiency Standards Program? Issues regarding internal cost accounting for energy sources such as coal/gas/diesel sourced internally that may affect project payback calculations?

23. EEO Energy Use Rules currently include – solar, wind, water and geothermal energy use for electricity generation. Are there any potential considerations for specific requirements or exclusion of these energy sources?

National Energy and Greenhouse Reporting

Announced Commitment

The Government has committed to publishing annual facility-level greenhouse gas emissions and electricity production data for electricity generators. This requires amendments to the *National Energy and Greenhouse Reporting Act 2007* (NGER Act) to allow for publication of this data by the Greenhouse and Energy Data Officer (GEDO).

Context

Publication of NGER emission and energy production data at facility-level will better inform markets and the community about the performance of electricity generators as Australia moves to a low carbon economy. The electricity sector represents more than a third of Australia's greenhouse gas emissions and it is important for greater information to be available regarding the emissions intensity of existing generators.

Under the *National Greenhouse and Energy Reporting Act 2007* (the NGER Act), reporting entities are obliged to report information regarding their greenhouse gas emissions, energy production and energy consumption to the Greenhouse and Energy Data Officer (GEDO), provided certain thresholds are met. For financial year 2010-11, controlling corporations are required to register and report if:

1. they or a member of their corporate group have operational control of a facility that emits 25 kilotonnes or more of greenhouse gases (CO_2-e), or produces or consumes 100 terajoules or more of energy; or
2. their corporate group emits 50 kilotonnes or more of greenhouse gases (CO_2-e), or produces or consumes 200 terajoules or more of energy.

Reporting entities will need to provide their 2010-11 report to the GEDO by 31 October 2011.

Section 24 of the NGER Act requires the GEDO to publish each registered controlling corporation's scope 1 emissions, scope 2 emissions and energy consumption by 28 February following each NGERS reporting (financial) year. Therefore, 2010-11 NGER data will be published by 28 February 2012.

Proposed way forward

Coverage

The Government has committed to publishing annual facility-level greenhouse gas emissions and electricity production data for electricity generators, supplied under the NGER Act.

As such facility-level emissions and electricity production data would be published for electricity generation facilities with emissions over 25 kt or energy production over 100 terajoules (TJ) per year.

Implementation and administration

As generators must already report this data (as all would normally meet the relevant thresholds for reporting) the proposal to publish facility level emissions and electricity data will not require them to report any additional information.

In order to implement this commitment, an amendment would be made to the NGER Act requiring the GEDO to publish facility level emissions and electricity production data reported by electricity generators, similar to the GEDO's existing data publishing obligations under section 24 of the NGER Act. This amendment would apply to the 2010-11 reporting year, with the first set of facility-level data for generation being published by 28 February 2012.

Controlling corporations that are required to report their greenhouse gas emissions and energy data can apply under section 25 of the NGER Act to request to have their information withheld from publication where it considers that publication of the information in question reveals, or could reveal, trade secrets or other confidential information that has a commercial value and such disclosure may destroy or diminish the value of the trade secrets or other information. To give effect to the commitment that emissions and energy production data for electricity generators at facility-level is publicly available, it is envisaged that electricity generators would not have access to this provision.

The amendments to the NGER Act would need to provide or make reference to a definition of an electricity generation facility. The *NGER Regulations 2008* defines industry sectors by Australian and New Zealand Standard Industrial Classification (ANZSIC) codes. Electricity generation is identified by ANZSIC code 261, which covers the industrial sub-sectors of fossil-fuel electricity generation, hydro-electricity generation and other electricity generation (which includes other types of renewable generation such as wind). The NGER Regulations also define a facility as an activity or series of activities attributable to a single industry sector, with the principal activity at the facility determining what industry sector each facility should be attributable to. These definitions would be replicated in the NGER Act to identify facilities that will have their data published by the GEDO by restricting the publication of facility-level emissions and electricity production data to cover only those facilities where the *principal* activity is electricity generation as identified by ANZSIC code 261.

This would mean other facilities where electricity is generated but where the principal activity is not electricity generation would not have their data published. For example, landfill sites which generate electricity from landfill gas or sugar mills that generate electricity from sugar cane bagasse would not have facility-level data published.

KEY QUESTIONS FOR STAKEHOLDERS

Stakeholder views are welcomed on all aspects of this discussion paper, in particular the following:

24. Should the definition of an electricity generation facility cover all types of electricity generation identified under ANZSIC code 261?

25. Are there particular problems in publishing this data?

26. How could or should the annual publishing of emissions and electricity production data relate to any compliance arrangements for new plant under the emissions standard?

27. Could annual reporting at facility level (under current facility definitions) create any unintended incentives, inconsistent with reducing costs in moving towards a low carbon future?

How to Respond

The ITG is seeking written submissions from interested individuals and organisations **preferably in electronic form submitted** by email to cleanerfuturepowerstations@ret.gov.au as an attached Adobe PDF or MS Word format document. The email must include full postal address and contact details.

Submissions should be received by 24 December 2010.

Written submissions may be submitted in hard copy/and or an electronic copy by e-mail, or letter to:

Cleaner Future Power Stations ITG Secretariat
Energy and Environment Division
Department of Resources, Energy and Tourism

E-mail: cleanerfuturepowerstations@ret.gov.au

Industry House
9/10 Binara St
Canberra City, ACT 2601
GPO Box 1564,
Canberra City, ACT 2601

Important: Please indicate clearly if you want your submission to be treated as confidential (that is, not to be made public) or anonymous (that is, the content can be made public but the author is not to be disclosed).

Confidentiality statement

All submissions will be treated as public documents, unless the author of the submission clearly indicates the contrary by marking all or part of the submission as 'confidential'. Public submissions may be published in full on the website, including any personal information of authors and/or other third parties contained in the submission. If your submission contains the personal information of any third party individuals, please indicate on the cover of your submission if they have not consented to the publication of their information. A request made under the *Freedom of Information Act 1982* for access to a submission marked confidential will be determined in accordance with that Act.

An electronic copy of the consultation document is available at: http://www.ret.gov.au

Next Steps

The ITG intends to hold a stakeholder forum on 16 December 2010 to hear stakeholder views on this discussion paper.

The ITG intends to consult stakeholders on the *Regulatory Impact Statement* relating to these measures in early 2011.

The ITG also intends to consult stakeholders on the *Exposure Draft* legislation on these measures.

energy supply association of australia

The impact of an ETS on the energy supply industry

Modelling the impacts of an emissions trading scheme on the NEM and SWIS

July 2008

Preface

The Energy Supply Association of Australia (esaa) supports the development of a well-designed national emissions trading scheme (ETS) as the primary policy measure to reduce Australia's greenhouse gas emissions in a least cost and efficient manner.

A well-designed national ETS will promote a reliable and sustainable energy supply system that in the long term delivers low carbon intensity electricity and gas supplies for Australia.

Implementing an effective national ETS will be a major economic adjustment for the Australian economy, and in particular for the energy supply industry.

esaa commissioned ACIL Tasman to model the impact of a national ETS on the energy supply industry as part of esaa's contribution to the development of a detailed understanding of the impact of a national ETS.

The ACIL Tasman study provides accurate and credible modelling of the effects of a national ETS on the energy supply sector up to 2020.

The modelling measured real price changes in electricity and gas, along with the level of new investment that would be required, in response to greenhouse gas reduction targets of 10% and 20% below 2000 emission levels by 2020. The modelling also included the Federal Government's Mandatory Renewable Energy Target (MRET) of 20% of electricity supply from renewables by 2020.

The study will now be made available to stakeholders to assist in the development of an efficient, effective and equitable ETS.

Key Messages

An ETS is an effective greenhouse gas abatement policy tool that can deliver least-cost abatement but real energy costs for consumers may rise significantly.

The study concludes that an ETS could work as an effective and efficient greenhouse gas abatement policy tool:

- The modelled ETS achieves abatement targets at the lowest cost by retiring or reducing output of more costly emission-intensive plant and substituting with least cost lower emission alternatives (and assumes a smooth transition – see potential design risks below).

- The 10% and 20% emission reductions result in emission levels in 2020 in the energy sector or 146 and 127 million tonnes of carbon dioxide equivalent ($MtCO_2e$) respectively, compared to the modelled business as usual (BAU) projection of 222 Mt in 2020 for the sector.[1]

The study found an ETS could deliver least cost abatement, but real energy costs may rise significantly:

- The carbon prices needed to achieve the 10% and 20% reductions started at approximately \$20/tonne CO_2e in 2010 and increased rapidly to \$45 and \$55 respectively.

The BAU projection found real electricity retail tariffs increased by 12% and real wholesale electricity costs increased on average by 26% by 2020:

- Relative to BAU retail tariff and wholesale cost increases, the 10% and 20% emission reduction targets increased:[2]
    - real electricity tariffs by approximately 24% and 28% respectively.
    - real wholesale electricity costs by between 25% and 55% in the 10% target in the various regions of the National Electricity Market (NEM), and by between 25% and 68% in the 20% target in the NEM. Wholesale electricity costs rose by 90% and 106% in the Western Australian market (the South West Interconnected System) in the 10% and 20% targets respectively.

- Natural gas prices increased under all scenarios due to stronger links to global markets, and higher gas-fired generation and production costs.

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[1] These outcomes in turn are 24% and 34% reductions over current projected emission levels in the sector by 2010.
[2] Including the additional costs associated with meeting the expanded MRET of 20% renewable generation by 2020.

Increased prices could reduce electricity demand growth.

- The study found that overall demand increased at rates 12% and 14% lower than BAU growth in the 10% and 20% emissions reduction scenarios respectively[3] (a reduction of more than 30,000 gigawatt hours (GWh)).
- Household demand was more responsive, reducing 20% and 23% relative to BAU (a reduction of approximately 15,000 GWh).

Reducing emissions could require at least a factor of three increase in investment in electricity generation.

- The required capital investment in electricity generation increased from $13b in the BAU case to $33b and $36b to achieve 10% and 20% emissions cuts respectively, inclusive of the $23b investment required to achieve the MRET of 20% renewable electricity generation by 2020.
  - This investment requirement is approximately the equivalent of the total estimated value of Australia’s existing generation fleet.
- To replace stranded plant, satisfy the MRET and meet load growth, 15,000 and 17,600 megawatts (MW) of new capacity was required to achieve the 10% and 20% emission target cuts respectively. This equates to approximately one third of Australia’s current generation capacity.
- To connect new remotely located generation and increase gas pipeline capacity, the study found at least $4.5b of additional investment would be required.

An ETS could strand several existing large scale capital investments and reduce the value of many others.

- Modelling of the 10% and 20% cuts prematurely stranded approximately 6700 MW and 10,400 MW of generation capacity respectively in the NEM. Most of the impact is concentrated in Victoria and South Australia with the 10% reduction forcing the closure of the majority of the existing coal plant in these states.
- An emissions trading scheme will change the merit order in the NEM, reducing volume and net revenue for incumbent fossil fuel generators by between 40% and 95%.

[3] Existing Trade Exposed Energy Intensive (TEEI) industries were assumed to be shielded from the price impacts, but new investment was reduced.

The MRET of 20% renewable electricity generation by 2020 could be achieved, adding approximately 5% in real terms to retail tariffs by 2020.

- The MRET renewable energy certificates will continue to be needed, as the modelled ETS carbon price was not sufficient to achieve the 20% renewables target.
- The cost of achieving the 10% and 20% emission reduction targets using both an ETS cost of carbon and the MRET was higher than least cost, given that the model disclosed an abatement cost for wind generation that was $10 to $40 higher per tonne of CO_2 than gas-fired generation.
- The study assumed that geothermal generation has the potential to provide 30% of the expanded MRET by 2020, subject to demonstration meeting expectations and the necessary transmission being built.

ETS policy design and transition must also manage the significant implementation risks that the modelled simulations did not capture.

- The modelling assumed perfect alignment between closure of existing plant and entry of new generation, and any required network investment, which may not happen in reality.
- To achieve a 10% reduction in emissions required retirement of 6700 MW and investment in approximately 15,000 MW of new plant. This rate of investment has not been attempted previously in the energy sector in Australia.
- Investment capital for new generation may be limited or demand higher returns in response to a perceived increase in investment risk.
- Indigenous gas supply limitations are apparent in South East Australia at prevailing 2020 prices in the years following 2020, which may limit investment in gas generation in the period.
- Full auctioning of emission permits, without compensation, may trigger impairment tests and breach loan covenants for some generators potentially before scheme implementation.
- Regulated retail prices will need to be cost reflective and flexible, to encourage efficient demand side response and allow retailers to meet the costs of contracting with marginal generators, and thus ensure supply reliability.
- Environmental and other approvals may prevent or delay new entrants in the scale required, particularly for wind generation and electricity transmission.

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Life-Cycle Greenhouse-Gas Emissions Inventory For Fischer-Tropsch Fuels

Prepared for

U.S. Department of Energy
National Energy Technology Laboratory

Prepared by

Energy and Environmental Solutions, LLC

John J. Marano
Jared P. Ciferno

June 2001

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DISCLAIMER

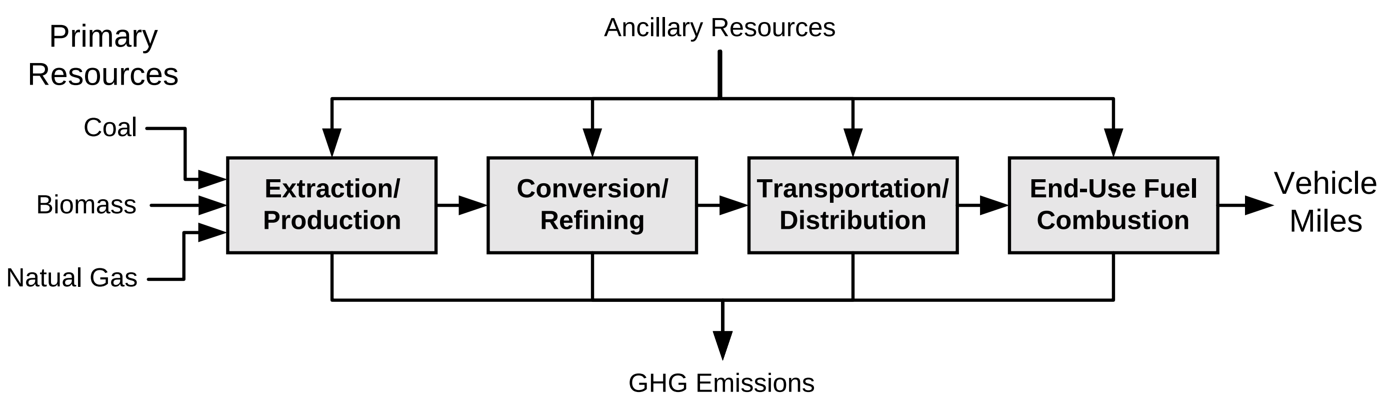
EXECUTIVE SUMMARY

This report discusses the development of greenhouse gas (GHG) emissions estimates for the production of Fischer-Tropsch (FT) derived fuels (in particular, FT diesel), makes comparisons of these estimates to reported literature values for petroleum-derived diesel, and outlines strategies for substantially reducing these emissions. This report is the product of the first phase of a comprehensive assessment being conducted by Energy and Environmental Solutions (E^2S), LLC, for the National Energy Technology Center (NETL) to characterize the impact, both short and long term, of FT fuel production on the environment and on human health and well-being.

This study involved the development of GHG inventories for a number of conceptual FT process designs. It also included the development of preliminary estimates for criteria pollutant emissions. The next phase of this assessment will address life-cycle improvements for FT fuels by targeting specific process changes aimed at reducing GHG emissions. Preliminary results have identified promising reduction strategies and these estimates have been included in this document. Future research will be focused on expanding the current emissions inventory to include a broader range of multimedia emissions of interest to NETL programs, and on performing economic analyses corresponding to the new low-emission FT process designs developed.

Baseline GHG Inventory

The objective of this study was to conduct a *full* life-cycle inventory (LCI) of greenhouse gas emissions for synthetic fuels produced using the FT process. As shown below, the LCI is based on a "*cradle-to-grave*" approach and includes data identification, collection and estimation of GHG emissions from *upstream extraction/production, conversion/refining, transportation/distribution, and end-use combustion of FT fuels* derived from three types of feedstocks: coal, biomass and natural gas.



The material and energy balances used for this analysis are from conceptual process designs developed for DOE in the 1990s for coal liquefaction and gas-to-liquid (GTL) plants[1].

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1. Bechtel, Inc. *Baseline Design /Economics for Advanced Fischer-Tropsch Technology* (various reports), DOE Contract No. DE-AC22-91PC90027 (1993-1998).

***Background*:** The analysis presented in this report is limited to a LCI of airborne emissions produced along the FT fuel product life cycle. It is not a *complete* inventory of all emissions, though it could be used as a starting point for one, since it lays out *a formal methodology for conducting an analysis for FT derived fuels*. The impact of various greenhouse gases has been considered in relative terms by converting all GHG emissions to a CO_2 equivalency basis. The LCI is based on earlier FT plant designs, and no effort has been made to improve on these conceptual designs.

The greenhouse gases considered are CO_2 (carbon dioxide) from syngas production, FT synthesis, fossil-fuel combustion along the life-cycle, and venting from natural gas production; CH_4 (methane) from fugitive plant and pipeline emissions, incomplete combustion or incineration (gas flaring), and coalbed methane releases; and N_2O (nitrous oxide) from fuel combustion and the cultivation of biomass. The weighting factors for CH_4 and N_2O used in the CO_2 equivalency calculations are 21 and 310, respectively. Data were also compiled, where possible, for emissions of criteria pollutants (CP): CO (carbon monoxide), NOx (nitrogen oxides), SOx (sulfur oxides), VOC (Volatile Organic Compounds), and PM (Particulate Matter). Normally, these emissions are not included in CO_2 equivalency calculations, because the mechanism of their participation in global warming is not fully understood. For the FT conversion process, a checklist of air toxics sources has also been prepared.

Assumptions relative to the geography of the product supply chain (*fuel chain*) are critical when comparing life-cycle emissions estimates. The U.S. Midwest (southern Illinois) has been chosen as a reasonable location for the future siting of coal liquefaction plants, as well as biomass conversion plants. A Wyoming location was also chosen for a second coal scenario based on the conversion of subbituminous coal. For these scenarios, it was assumed that the FT diesel fuel is supplied to an area in the vicinity of Chicago, IL by pipeline and tank truck. Three locations were considered for siting a GTL plant: southern Illinois, Venezuela, and Alaska. The southern Illinois location has been included to allow direct comparison between coal, biomass and natural gas scenarios. For Venezuela, it is assumed that FT syncrude is transported to the U.S. Gulf Coast by tanker and pipelined to the U.S. Midwest, where it is refined and blended into transportation diesel fuel near Chicago. It is assumed that GTL deployment on the North Slope of Alaska results in a syncrude that is transported via the Trans-Alaska pipeline to Valdez, transferred to a tanker, and shipped to the U.S. West Coast, where it is distributed in the San Francisco Bay area. These assumptions form the basis for the six baseline scenarios developed in this report.

Since FT conversion processes result in a multitude of products, some of which may not be used in transportation, careful consideration was given to how emissions should be *allocated* between the various products. *For this study, emissions from conversion/refining, and all other upstream operations have been allocated between LPG, gasoline and distillate fuel products based on the ratio of their energy content (LHV-basis) to the energy content of all products*. It is unlikely that more complicated procedures would result in substantially different results, since the energy densities of these liquid fuels are similar. However, this procedure was not considered appropriate when electric power was produced as a major by-product of FT production. *Emissions are allocated to power based on the energy content of the fuel used in the electrical conversion device* (gas or steam turbine); that is, the energy content of the electrical power is divided by turbine efficiency when determining the share of emissions to be allocated to this power. This is similar to the procedure used when calculating the *thermal efficiency* of co-generation (power and steam) processes. *The allocation procedure used for fuels and power co-production has a significant effect on the reported emissions*. Further work is needed to validate any benefits of co-production.

The basis for the full FT fuel chain GHG emissions estimates reported here is vehicle-miles driven. This is the appropriate unit of measure for most, but not all, comparisons. Fuel economies in miles-per-gallon (mpg) are from a recent analysis conducted by Argonne National Laboratory (ANL)[2]. This analysis considered a wide range of conventional, advanced, and electric hybrid gasoline and diesel powered vehicles. Since the emissions estimates will change based on the fuel economy used for the comparison, the calculations have been incorporated into a spreadsheet to facilitate analysis of various alternatives with different mpg ratings. The values presented here are for sport utility vehicle (SUV) conversion from conventional gasoline engines to conventional and advanced diesel engines. The average fuel economy for gasoline-powered SUVs is 20 mpg, and for light-duty diesel-powered vehicles it is about 39 mpg. In similar applications, diesel engines are 33% more efficient than gasoline engines. Therefore, converting all SUVs powered by gasoline to diesel would result in a fuel economy increase to 26.6 mpg. Fuel composition also plays a critical role in determining fuel economy. Substituting FT diesel for petroleum diesel in SUVs would result in a decrease in fuel economy from 26.6 to about 24.4 mpg, an 8% decrease. This is a result of the inherent lower energy density per gallon of FT diesel relative to conventional petroleum diesel.

2. "Well-to-Wheel Efficiency Analysis Sees Direct-Hydrogen Fuel Cells, Advanced Diesel Hybrids Comparable," *Hart's Gas-to-Liquids News*, April 1999.

***Results*:** As part of this analysis, a large number of FT fuel-chain options were considered, including primary feedstock, production/extraction location and method, FT catalyst and upgrading, FT product slate, co-production of power, transportation method and distances, and end-use location.

FT Fuel-Chain Options

Feedstocks	**Production/ Extraction**	**Conversion/ Refining**	**Transportation/ Distribution**
Coals: • Illinois #6 – bituminous • Powder River Basin – subbituminous	Underground Mining: • S. Illinois Surface Mining: • S. Illinois • Wyoming	FT Conversion: • Iron Catalyst FT Upgrading: • Max Distillate • Max Naphtha • Chemicals	Mine-Mouth FT Plant: • S.IL to Chicago – Pipeline & Tank Truck • Wyo. to Chicago – Pipeline & Tank Truck
Biomass: • Maplewood	Plantation Crop: • S. Illinois	FT Conversion: • Iron Catalyst FT Upgrading: • Fuels & Power	FT Plant near Plantation: S.IL to Chicago – Pipeline & Tank Truck
Natural Gas: • Pipeline Gas • Associated Gas	Pipeline Gas: • S.Illinois Associated Gas: • Venezuela • Alaska North Slope	FT Conversion: • Cobalt Catalyst FT Upgrading: • Max Distillate • Min Upgrading • Fuels & Power	S.IL & Wellhead FT Plant: • S.IL to Chicago – Pipeline & Tank Truck • Venezuela to Chicago – Tanker, Pipeline & Tank Truck • Alaska to Chicago – Pipeline, Tanker & Tank Truck

The only end-use option considered here was diesel-powered SUVs, though cases can be quickly compiled for other applications using the information presented in this report.

A summary of selected results from the GHG emissions inventory developed for FT diesel is given below. Also included are literature estimates for petroleum-derived diesels from imported Arab Light crude oil and a partially upgraded Venezuelan syncrude[3]. Literature data was also used to estimate emissions for Alaska North Slope (ANS) and Wyoming crude oils of direct interest to this study.

Full Life-Cycle GHG Emissions for FT & Petroleum Diesel Scenarios
(g CO_2-eq/mile in SUV)

Feedstock	Extraction/ Production	Conversion/ Refining	Transport./ Distribution	End Use Combustion	Total Fuel Chain
IL #6 Coal baseline	26	543	1	368	939
- in advanced diesel*	23	472	1	320	816
Wyoming Coal	7	585	2	368	962
Plantation Biomass	-969	703	1	368	104
Pipeline Natural Gas	71	121	1	368	562
Venezuelan Assoc. Gas	51	212	12	368	643
- with flaring credit*	-527	212	12	368	65
ANS Associated Gas	51	212	21	368	652
Wyoming Sweet Crude Oil	23	74	8	363	468
Arab Light Crude Oil	35	81	26	367	509
ANS Crude Oil	28	101	14	378	522
Venezuelan Syncrude	32	143	10	390	574

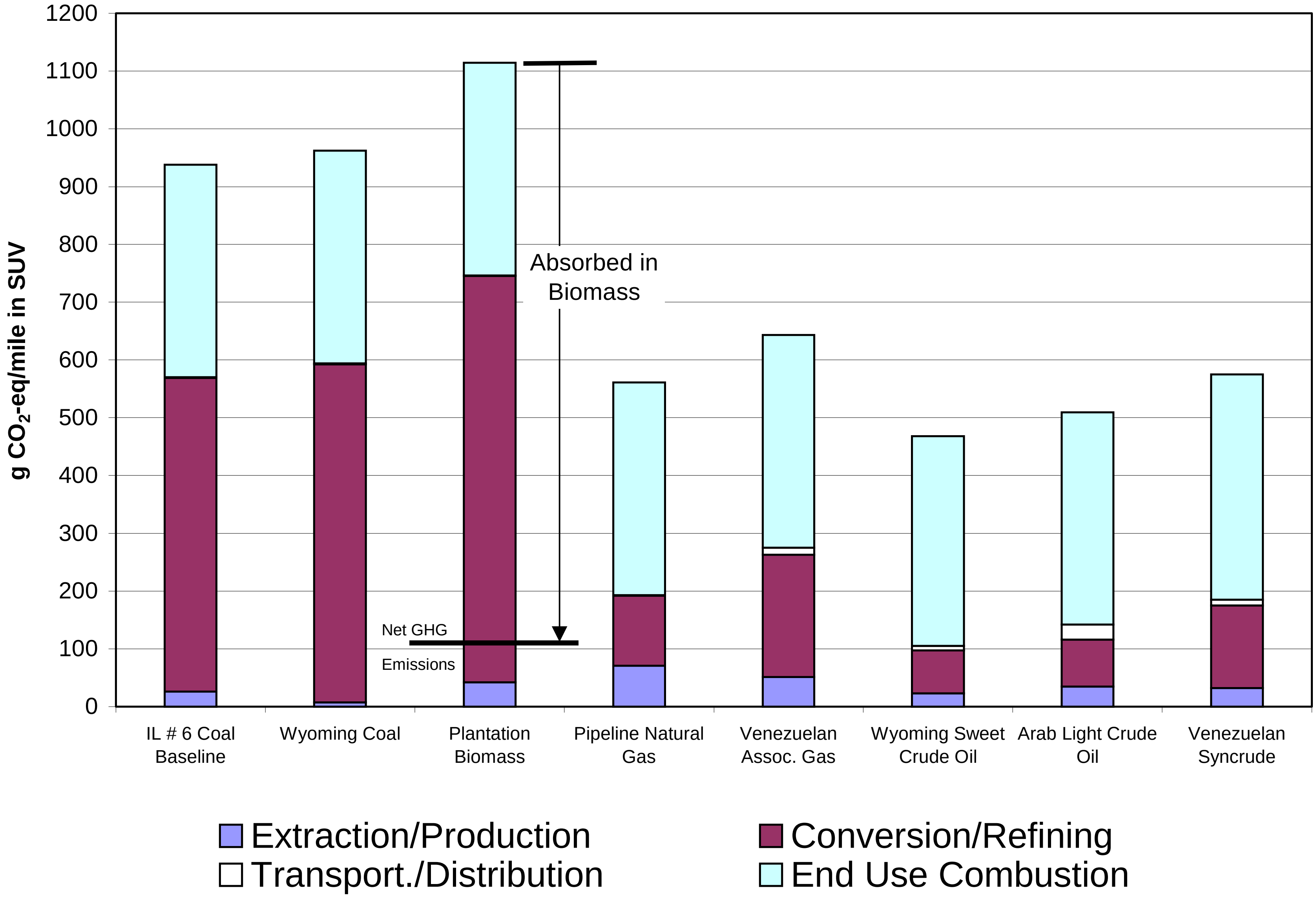
*selected cases from sensitivity analysis.

The figure given on the following page compares graphically the GHG emissions for those baseline scenarios listed above, which produce diesel fuel for the Chicago market.

The results in this table and figure illustrate a number of interesting points. Emissions from transportation (1 to 26 g CO_2-eq/mile) correlate with the distance the fuel or feedstock is moved to market. Thus, in a carbon-constrained world it may not make environmental sense to move oil (or any other commodity) halfway around the world. Transportation emissions are low for domestic coal and biomass-based FT conversion due to the close vicinity of the coal field or plantation and the FT plant to the fuel market (Chicago). The end-use combustion emissions for FT diesel have been assumed constant (368 g/mile in conventional diesel and 320 g/mile in advanced diesel), since the different feedstocks are being refined to produce similar quality products. Emissions for petroleum-derived diesel vary with the quality of the crude oil from which they were produced (363-390 g/mile). Heavier crudes require more upgrading and refining and produce less desirable by-products.

3. Tom McCann and Phil Magee of T.J. McCann & Associate Ltd., Calgary, "Crude Oil Greenhouse Gas Life Cycle Analysis Helps Assign Values For CO2 Emissions Trading," *Oil & Gas J.*, Feb. 22, 1999, pp. 38-44.

Full Life-Cycle GHG Emissions for FT & Petroleum Diesel Scenarios



For coal and biomass, the largest single source of emissions is the indirect liquefaction (FT conversion) facility (543 to 703 g CO_2-eq/mile), with GHG emissions even larger than those for end-use combustion. For pipeline natural gas, GTL emissions (121 g/mile) are lower than GHG emissions for end-use combustion. Carbon and oxygen must be removed from coal and biomass to convert them into a liquid. This step requires energy and consumes synthesis gas (H_2 and CO). The GTL process essentially extracts hydrogen from methane to produce liquid fuels. However, there is still a significant emissions penalty with GTL due to energy consumption during conversion. If the produced natural gas contains significant quantities of CO_2, emissions of GHG from conversion can be dramatically higher (212 vs. 121 g/mile, respectively). While combustion dominates total emissions for petroleum-based diesel, the other contributing sources are not insignificant. Conversion and refining emissions (74-143 g/mile), the second largest contributor, also vary with crude quality.

With improved fuel efficiency less fuel is consumed per mile and less fuel must be produced and transported. The net result of the adoption of next-generation advanced-diesel engine technology is an across the board 13% reduction in emissions per mile for all categories. This applies not only to the baseline IL #6 coal scenario, but to all the other scenarios listed above as well. In general, CP emissions from FT diesel combustion are lower than those from petroleum-derived diesel, making FT diesel an ideal alternative to petroleum-derived diesel in advanced engines.

While biomass conversion emissions are higher than those for coal (703 vs. 543-585 g CO_2-eq/mile); overall, the full-fuel chain GHG emissions for biomass-based FT fuels is very low (104 g/mile). Biomass is a renewable resource, and the carbon it contains is recycled between the atmosphere and the fuel, resulting in the fixation of 1011 g of atmospheric CO_2 in the biomass on a per mile basis. However, biomass cultivation and harvesting result in GHG emissions (42 g/mile), and biofuels should not be considered CO_2 emissions free.

The production of FT diesel from coal results in significantly higher total GHG emissions than those from petroleum-derived diesel (939-962 vs. 468-574 g CO_2-eq/mile). GTL technology can achieve GHG emissions levels between those for coal liquefaction and petroleum refining (562-652 g/mile), due to the higher hydrogen content of methane relative to petroleum (4 to 1 vs. ~2 to 1). In fact, the GHG emissions for FT diesel from natural gas are lower than the emissions for Venezuelan syncrude (562 vs. 574 g/mile) which requires severe processing to make it suitable as a feedstock for refining.

In some parts of the world, a significant amount of associated gas is flared, because there is no readily available market for this natural gas. When credit is taken for eliminating flaring, full fuel-chain emissions are cut drastically (from 643 to 65 g CO_2-eq/mile). The elimination of flaring and venting could under future regulations result in “carbon-credits” which could be sold in any market-based approach to reducing GHG emissions worldwide.

GHG Reductions Strategies

With the goal of identifying promising strategies for further study in mind, a preliminary examination was made of options for reducing GHG emissions from the production of FT derived fuels from coal. Material and energy balance models will be required to develop new conceptual designs for FT conversion processes employing these strategies and this will be the focus of future work. The FT plant designs considered up to this point were developed in the early 1990s, when global warming was not yet considered a substantiated threat. As such, cost reduction was the major driver in the development of the conceptual designs, not GHG reduction or efficiency improvement.

Sensitivity Analysis**:** In order to help identify possible GHG reduction strategies for FT fuels production, a number of sensitivities were considered to the scenarios discussed above. These were particularly easy to estimate based on the detailed energy and material balances from the conceptual process designs. However, they only represent what may be possible, since they do not include any analysis (re-design) of the conceptual FT process they were based on. The sensitivities considered, in order of increasing GHG emissions reduction potential, are:

- Coalbed methane capture (maximum 2.3% reduction)
- Co-processing of coal and biomass (17%)
- Co-processing of coal and coalbed methane (25%)
- Co-production of fuels and power (32%)
- Sequestration of process CO_2 produced and vented during FT production (48%)
- Sequestration of process CO_2 and CO_2 from fuel combustion during FT production (55%)

Coalbed methane is released during coal mining and post-mining operations. While the magnitude of these releases is relatively small, the potency of methane as a GHG is quite high. Co-processing refers to the production of FT fuels from multiple feedstocks; for example, coal with methane and/or biomass. Since the latter have low GHG emissions relative to coal, co-processing has a moderating effect on the GHG emissions associated with FT fuels produced only from coal. Co-production refers to the production of multiple products from the indirect liquefaction plant; in this case, both fuels and power. Eliminating the recycle of off-gas produced in the FT conversion process, which can be used to produce electric power, reduces GHG emissions. Sequestration involves the collection, concentration, transportation and storage of CO_2 to reduce GHG emissions.

It is clear that many of the options discussed above will impose an energy and/or economic penalty on FT fuel production. For example, sequestration could require the compression of CO_2 for transportation and possibly for injection of CO_2 into any potential sink, and the production of nearly pure CO_2 from fuel combustion will require the increased production of high-purity oxygen at the FT plant. Increased energy requirements will result in increased CO_2 emissions from fuel combustion. It should be further acknowledged that economics might favor some of the options listed above with the least impact. For example, coalbed methane capture has an economic benefit in that coalbed methane can be sold as natural gas.

Based on potential economic, geographic and process synergies between the GHG reduction options listed above, estimates for three GHG reduction scenarios have been developed illustrating the incremental benefits of these options. These are:

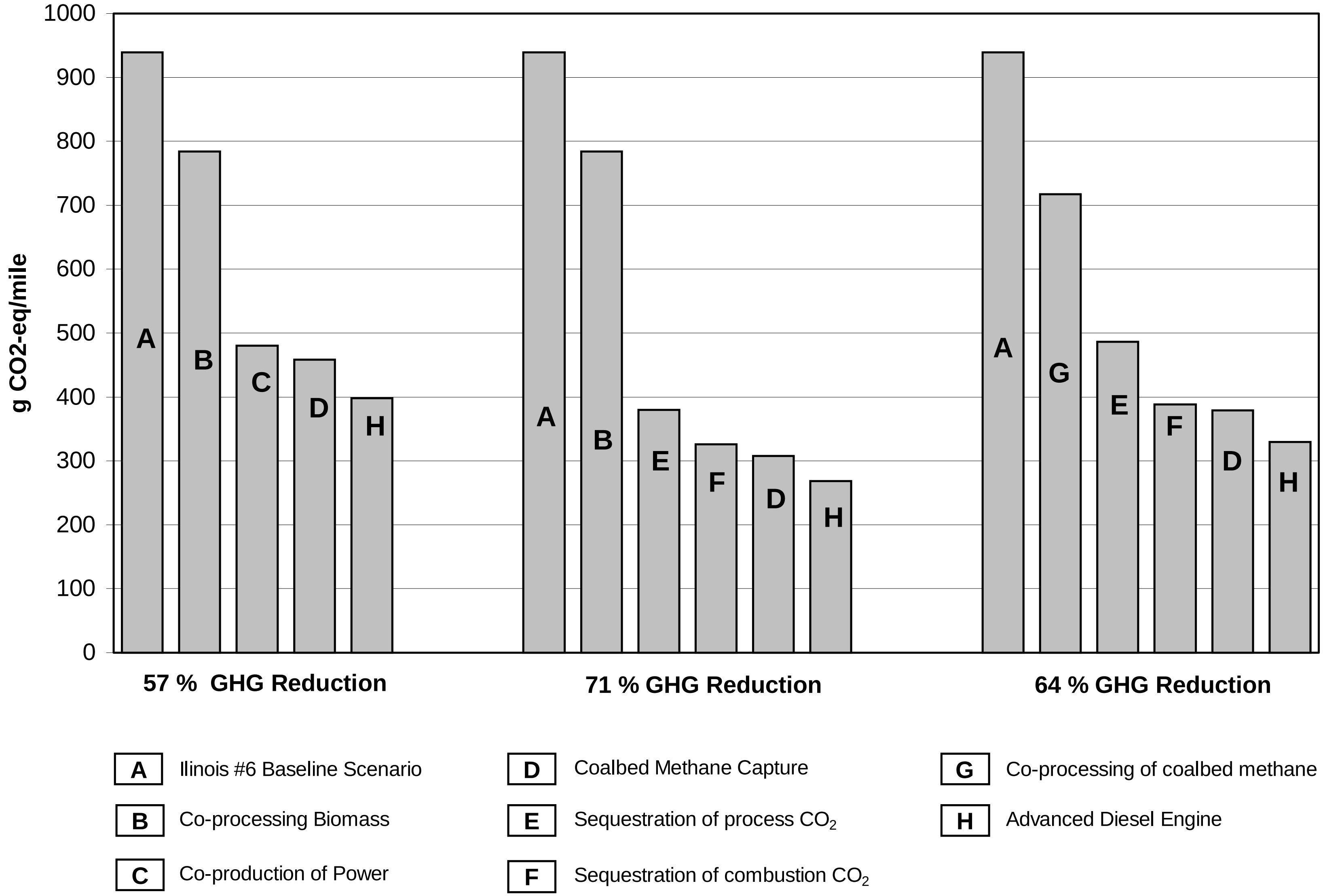
- Co-processing of coal and biomass coupled with co-production of fuels and electric power and coalbed methane capture
- Co-processing of coal and biomass coupled with CO_2 sequestration and coalbed methane capture

- Co-processing of coal and coalbed methane from mined and unmined coal seams coupled with CO_2 sequestration in the unmined seams

The figure given on the following page illustrates the incremental benefits of combining GHG reduction strategies. The scenario involving coal and biomass co-processing coupled with sequestration shows the biggest GHG emissions reduction, 71% vs. 57% for biomass co-processing with co-production of power and 64% for coalbed methane co-processing with sequestration. To account for emissions penalties associated with implementing these strategies, rough estimates have been included for the efficiency of coalbed methane capture (80%), sequestration of process CO_2 (90%) and sequestration of CO_2 from combustion (80%).

All of the reduction scenarios achieve GHG emissions lower than those currently estimated for petroleum diesel fuel (286-442 vs. 468-574 g CO_2-eq/mile, respectively). However, it must be reiterated that *this analysis only identifies what may be possible*. Too much uncertainty exists in these estimates to consider any one of these scenarios better than another. Further detailed analysis will be needed to accurately quantify these future scenarios, and technology breakthroughs will be required in CO_2 sequestration, oxygen separation, and combustion technology to achieve these benefits. In addition, it must be kept in mind that petroleum production and refining would also benefit from similar strategies and technologies.

Comparison of Strategies for Reducing GHG Emissions for FT Diesel



***Cost Impact*:** Many of the options considered here might be expensive to implement. Current estimates by Bechtel for the cost of indirect liquefaction correspond to a required selling price for the FT products of roughly $1.24 per gal (1998$s before taxes and marketing charges). However, there is reason to believe that rapid technology improvement in oxygen separation, coal gasification, and FT conversion could lower this price by as much as $0.20 per gal. This, coupled with the premium which FT diesel is likely to command, puts FT fuels in a near-competitive range with petroleum-derived gasoline and diesel.

Recent DOE estimates for the cost of sequestration technologies (other than forest sinks) are well over $100 per ton of carbon sequestered. The estimates for future technologies under development range anywhere from $5 to $100 per ton. The DOE carbon sequestration program has a goal of driving down the cost of sequestration to $10 per ton through aggressive technology development. While the CO_2 emissions from indirect coal liquefaction are high, the process has a significant advantage in that CO_2 can be removed from the process as a concentrated stream that could easily be sequestered. Based on these estimates then, the cost of CO_2 sequestration from indirect liquefaction is about $0.33 per gal based on $100 per ton and $0.02 per gal based on the DOE target of $10 per ton. The broad range of this potential added cost, and the possibility that it could wipe-out the significant cost reductions obtained over the last decade, *make it paramount that efforts to reduce the cost of FT conversion be continued*.

In the immediate future, only limited supplies of low-cost biomass are available for conversion. E^2S estimates the required selling price of FT fuels derived from biomass range anywhere from $2.00 to $2.30 per gal, depending on the source of the biomass. *Unless these costs can be reduced and the biomass resource base expanded, this option is likely to play only an incremental, albeit potentially important, role in GHG reduction strategies*.

The optimum coupling of all three strategies, sequestration, co-production, and co-processing, may be a very attractive GHG mitigation strategy to minimize both GHG emissions and their cost impact on indirect liquefaction. Thus, there is a pressing need to carefully examine in detail both the technology options for GHG emissions reduction and their cost impact on the FT product.

Conclusions & Recommendations

This analysis has identified and quantified significant sources of GHG emissions from the FT fuel chain. At present, GHG emissions from the FT fuel chain are greater than those from existing, petroleum-based fuel chain. Coal-based conversion is at a significant disadvantage relative to petroleum. Whereas, natural gas conversion is only moderately worse than the best petroleum scenarios and is better than the production and refining of heavy crude oils. In order for FT technology to be accepted in a world that is becoming more-and-more conscious of the effects of burning fossil fuels, it will be necessary to identify strategies and technologies for reducing these emissions. This study has been able to identify a number of possible approaches, including carbon sequestration, co-production of fuels and power, and co-processing of coal and biomass or coal and coalbed methane. Improvements in vehicle technology will also benefit the FT fuel chain by increasing fuel economy and, thus, reducing emissions per mile.

In order to evaluate the full potential of GHG reduction strategies for FT fuel production, all of the options considered here require better data and a more rigorous analysis beyond the scope of this preliminary analysis. Neither has a total view of the environmental benefits and deficiencies of FT fuels been realized in this study. A GHG emissions inventory has been completed, but only the first step has been taken toward developing a complete life-cycle inventory of all FT fuel chain impacts that affect the environment and human health and well being. Emissions of criteria pollutants have been identified for combustion sources along the fuel chain. Further work will be necessary to estimate emissions from vehicles fueled by FT diesel and gasoline and to expand this inventory to all categories of multimedia emissions.

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COMMON ACRONYMS

ANL	Argonne National Laboratory
ANS	Alaska North Slope
API	American Petroleum Institute
BCL	Battelle Columbus Laboratories
CP	Criteria Pollutants
DOE	U.S. Department Of Energy
EIA	DOE Energy Information Agency
EPA	U.S. Environmental Protection Agency
E^2S	Energy and Environmental Solutions, LLC
FT	Fischer-Tropsch
GHG	Greenhouse Gas
GTL	Gas-To-Liquid
GWP	Global Warming Potential
HAP	Hazardous Air Pollutants
HHV	Higher Heating Value
ILBD	Indirect Liquefaction Baseline Design
ISO	International Organization for Standardizations
LCA	Life Cycle Assessment
LCI	Life Cycle Inventory
LEBS	Low Emissions Boiler System
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MDEA	Methyl-Diethanol Amine
MF	Moisture Free
MTBE	Methyl Tert-Butyl Ether
NETL	National Energy Technology Laboratory
NG	Natural Gas
NGL	Natural Gas Liquids
NREL	National Renewable Energy Laboratory
NSPS	EPA New Source Performance Standards
PC	Pulverized Coal
POX	Partial Oxidation
PSA	Pressure Swing Absorption
SCOT	Shell Claus Offgas Treating
SETAC	Society of Environmental Toxicology and Chemistry
SUV	Sport Utility Vehicle
TAME	Tert-Amyl Methyl Ether
VOC	Volatile Organic Compounds
WGS	Water Gas Shift reaction

UNITS OF MEASURE

English units of measure have been used throughout the main body of this report. These are based on the units most commonly used to report specific data within the United States. For example, coal is commonly reported in "tons," crude oil in "barrels," gasoline in "gallons," etc. Appendix B gives the results from selected tables in standard Metric units. Given below are conversion factors for some units of measure frequently used in this report.

Mass:	1 Ton = 2,000 lb {pounds-mass} = 907.2 kg {kilograms} = 0.9072 Tonne {metric ton}
Energy:	1 Btu {British thermal unit} = 1,055.1 J {Joules} = 2.93×10^{-4} kWh {kilowatt-hours}
Distance:	1 mile = 5,280 ft {feet} = 1.6 km {kilometers}
Liquid Volume:	1 bbl {barrel} = 42 gal {gallons} = 5.615 ft^3 {cubic feet} = 159.0 l {liters} = 0.1590 m^3 {cubic meters}
Gas Volume:	1 scf {standard cubic foot @ 60^{o}F & 1 atm} = 26.8 Nl {Normal liters @ 0^{o}C & 1 atm}
Fuel Economy:	1 mpg {miles-per-gallon} = 0.4227 km/l {kilometers-per-liter}
Liquid Flowrate:	1 bpd {barrels-per-day} = 159.0 l/day {liters-per-day}
Temperature:	^{o}F {degree Fahrenheit} = 1.8×^{o}C {degree Celsius} + 32
API Gravity:	^{o}API = 141.5 / SpGr {specific gravity} - 131.5
English Prefixes:	MM {million} = 1,000 M {thousand} = 1,000,000
Metric Prefixes:	1 T {tera} = 10^3 G {giga} = 10^6 M {mega} = 10^9 k {kilo} = 10^{12}

1. INTRODUCTION

The objective of this project was to develop a full life-cycle inventory (LCI) of greenhouse gas (GHG) emissions for synthetic fuels produced using the Fischer-Tropsch (FT) process. Where possible, emissions of criteria pollutants have also been compiled, and for the FT conversion process, a checklist of air toxics sources has been prepared. The LCI is based on a "cradle-to-grave" approach and includes data identification, collection and estimation of GHG emissions from upstream extraction/production, conversion/refining, transportation/distribution, and end-use combustion of FT fuels derived from three different feedstocks: coal, biomass and natural gas. *This inventory is the first step in a comprehensive strategy to identify, predict and reduce emissions from indirect liquefaction processes used for the production of alternative fuels*.

The scope of work included:

- Development of an inventory methodology for compiling and reporting GHG and other emissions for FT fuels and feedstocks [*Section 2*];
- Analysis of conceptual designs for FT conversion processes and estimation of significant process emissions [*Section 3*];
- Collection and evaluation of emissions data for all processes upstream [*Section 4*] and downstream [*Section 5*] of the FT conversion plant;
- Estimation of emissions from end-use fuel combustion and ancillary processes [*Section 6*];
- Compilation of emissions for the *full* FT-fuel life-cycle [*Section 7.1*];
- Analysis of baseline scenarios for the substitution of FT diesel fuel for petroleum-derived gasoline and diesel in SUVs [*Section 7.2*];
- Comparison of GHG emissions for FT diesel fuel with petroleum-derived diesel in SUVs [*Section 7.4*]; and
- Development of strategies and recommendations for reducing life-cycle GHG emissions from FT fuel production [*Sections 7.3 & 7.5*].

In this study, special emphasis was placed on estimating the projected emissions from FT process plants. Data collection activities did not involve field measurements of emissions. The FT plants considered are conceptual processes, which may be constructed in the near future. The material and energy balances used for the analysis are from designs developed for DOE by Nexant, Inc. (formerly a division of Bechtel Corporation) in the 1990s. Emissions from all processes upstream or downstream of the FT conversion plant where compiled from other sources, including a number of other life-cycle emissions inventory analyses conducted by ANL, EIA, EPA, NETL, and NREL.

The rigorous baseline scenarios analyzed in Section 7 are assembled by matching data compiled in Sections 3 through 6 for the different options for producing, transporting, delivering and utilizing FT fuels to the assumptions used for the various scenarios. The scenarios developed for reducing GHG emissions from FT fuel production are based on a sensitivity analysis of the baseline scenarios. These order-of-magnitude estimates for GHG reduction strategies indicate it is possible to significantly reduce GHG emissions from FT fuel production. *Further in-depth analysis will be needed to accurately quantify these GHG reduction scenarios, and technology breakthroughs will be required in CO_2 sequestration, oxygen separation, and combustion technology to achieve these benefits.*

2. INVENTORY METHODOLOGY

The objective of this project was to develop a full life-cycle inventory of greenhouse gas emissions for Fischer-Tropsch fuels. The life-cycle inventory is only the first component of a general procedure known as *life-cycle assessment*. Life Cycle Assessment (LCA) is an analytical approach for qualifying and quantifying the environmental impacts of all processes used in the conversion of raw materials into a final product. LCA dates back to the late 1960s/early 1970s and has also been described as *full fuel-cycle* analysis, *ecobalancing* or *cradle-to-grave* analysis. What is conveyed by these names is that LCA attempts to quantify all significant impacts which arise from raw materials acquisition, manufacturing, transportation, use/reuse/maintenance, and recycle/disposal of a given product or service. It is increasingly becoming understood within policy circles that from a socio-economic perspective, any comparison of the environmental impacts from different products or services may be meaningless, or worse misleading, if only "across-the-fence" plant emissions are considered and all other impacts are ignored. LCA attempts to account for all consequences.

Broadly, LCA can be broken down into three distinct activities: *inventory analysis, impact assessment* and *improvement analysis*. Life-Cycle Inventory (LCI) Analysis catalogs and quantifies all materials and energy used and the environmental releases arising from all stages of the life of a product, from raw material acquisition to ultimate disposal. Life-Cycle Impact Assessment evaluates actual and potential environmental and human health consequences and resource depletion from (*that is, sustainability of*) all activities identified in the inventory phase. Life-Cycle Improvement Analysis aims at reducing any risks identified in the impact assessment, possibly by modifying stages in the product life cycle.

Prior to beginning an LCA, careful consideration must be given to the scope of the study. *Scope Definition* includes clearly identifying the purpose of the study (*What will it be used for?*) and identification of all assumptions to be used in, or restrictions to be placed upon, the assessment. Items to be considered include the selection of system boundaries; availability, quality and level of aggregation of data; classification and characterization of emissions; and the allocation of impacts to multiple products.

Within the U.S., the Society of Environmental Toxicology and Chemistry (SETAC) has been working to establish a standard framework for conducting LCA [1-4]. The International Organization for Standardization (ISO) has also developed a protocol for LCA as part of its ISO 14000 environmental management standards [5][4]. The framework used here has been adapted from these standards and protocols to reflect the needs of the National Energy Technology Laboratory's research programs. NETL is not a regulatory organization concerned with labeling products and procedures for the consumer. *This assessment is focused on making relative comparisons of existing and future technologies for producing transportation fuels, with the goal of improving these technologies through applied R&D.*

4. Information on the ISO 14000 Environmental Standards (EMS) can be accessed via *www. iso.ch.com* or *www.iso14000.com*.

The analysis reported here is a *full* LCI in the sense that the emissions being cataloged are tracked from cradle to grave. It includes emissions from *upstream extraction/production*, *conversion/refining*, *transportation/distribution*, and *end-use fuel combustion*. However, the LCI is not a *complete* inventory since only greenhouse gases and criteria pollutants were quantitatively considered, and air toxics are only covered qualitatively (that is, only a list of the compounds that must be reported to the EPA has been prepared). It should not be confused with or substituted for a complete LCA, since it does not meet the SETAC criteria of being multi-media in perspective, nor does it include rigorous impact assessment or improvement analysis. This said, the analysis does consider two important elements of impact assessment, classification and characterization of the GHG emissions cataloged. Neither has improvement analysis been completely ignored. During this inventory, several approaches became obvious for reducing GHG emissions from the FT fuel chain. Order-of-magnitude estimates for these promising reduction approaches are included in this report.

2.1 System Boundaries

Figure 1 shows the *fuel chain* associated with the production of liquid fuels based on the Fischer-Tropsch process. A two-tiered approach has been taken for the collection and organization of emissions inventory data for the fuel chain. All material and energy use and environmental releases along the fuel chain are classified as either *primary* or *ancillary*. This *streamlining* procedure has been used to simplify this analysis while still identifying and quantifying all significant impacts. Primary emissions result from the actual operation of the process steps making up the major systems identified in Figure 1. They are designated primary because they result from the processing of the primary resources, which in the cases considered here are coal, biomass and natural gas. Primary emissions occur on the direct path from cradle to grave. The designation primary is not intended to imply that these flows are always significant in relation to the entire life cycle. For example, CO_2 emissions from transport of gasoline between storage-terminal tankage and service (re-fueling) station are usually not significant relative to the entire fuel chain. However, they have been included for completeness in this LCI. Ancillary material and energy use and environmental release are *aggregated* data for all activities associated with the external flows into the major systems of the FT fuel chain (that is, the ancillary feedstocks). Ancillary emissions are included in the inventory unless otherwise noted and, in some cases, may be significant.

As indicated by Figure 1, the steps in converting the primary resource into the final product, transportation miles, are the same regardless of the feedstock: coal, biomass or natural gas. The first step is mining for coal, cultivation and harvesting for biomass, and oil and gas production for natural gas. The second step is conversion. For FT-based conversion to fuels, this step involves gasification of coal or biomass and partial oxidation/reforming for natural gas. The resulting syngas (synthesis gas, a mixture containing H_2 and CO) is then converted via Fischer-Tropsch synthesis into liquid hydrocarbons suitable for the manufacture of fuels and chemicals. This conversion step is often referred to as indirect liquefaction for coal and biomass and gas-to-liquid conversion for natural gas.

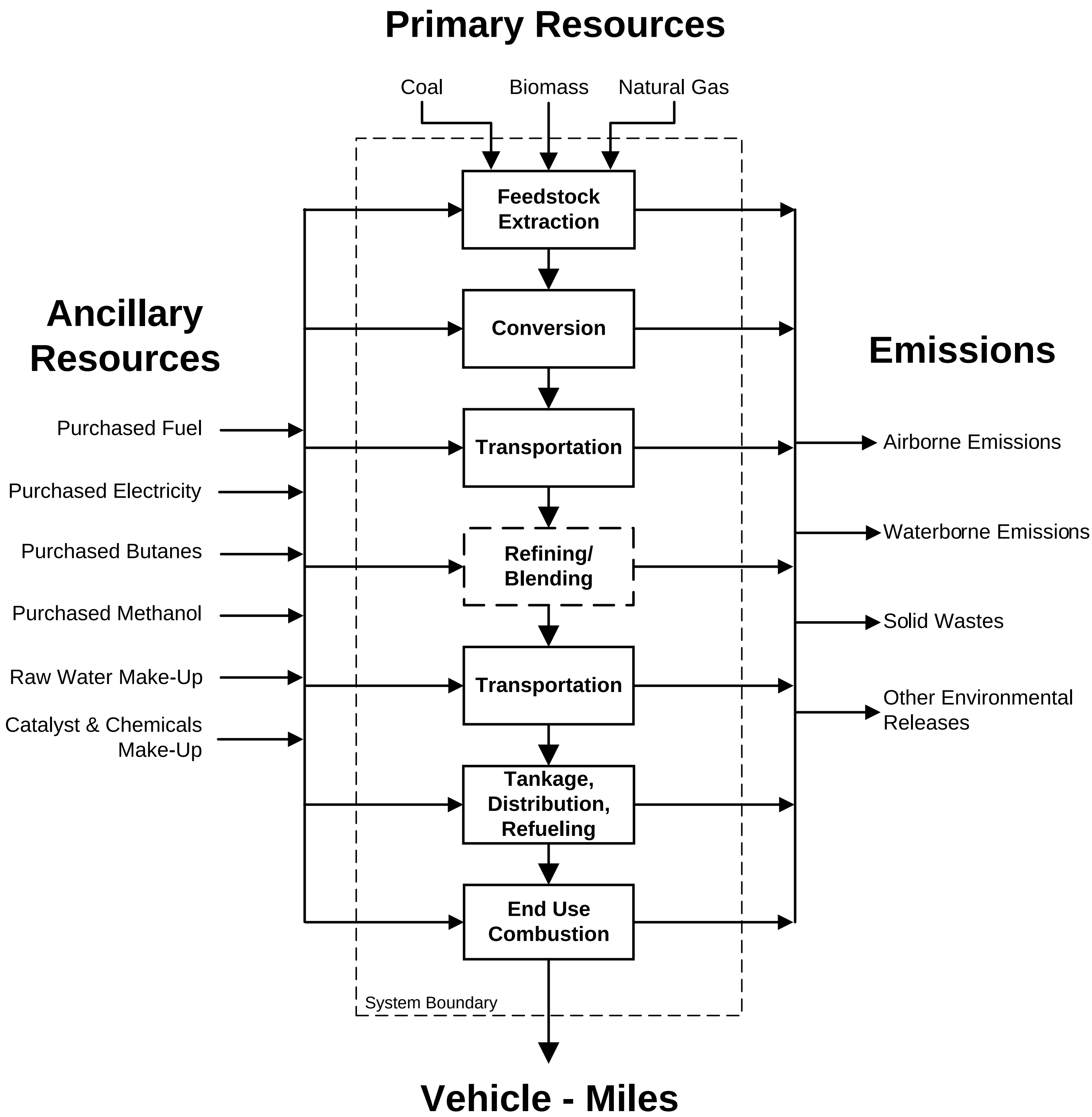


Figure 1. FT Fuel Chain

It is assumed in all the scenarios considered here (with the exception of the scenario based on pipeline gas) that the conversion step occurs in close proximity to feedstock extraction and remote from the end-use markets for the fuels produced. Thus, one step involves the transportation of the synthetic FT fuel from the liquefaction plant to market. In reality, a number of intermediate steps occur along the way, possibly including further refining of the raw FT fuel into specification fuels (e.g. gasoline, jet and diesel fuel). The refining step might include processes as severe as hydrocracking and/or fluid catalytic cracking or as simple as blending with refined petroleum fuels. In Figure 1, the refining step has been shown as a dashed block to indicate that it may or may not be distinct from the conversion step. Examples of both situations are found in the FT design options considered.

From the refinery, the specification fuels are transported in a second transportation step to intermediate storage and distribution centers (tank farms) for final distribution to the consumer at service/re-fueling stations. Tankage, distribution and refueling are lumped together as a sixth step in Figure 1. The final step in the FT fuel chain is end-use combustion. This LCI focuses on the final use of these fuels for transportation, in particular vehicles employing conventional and advanced diesel engines.

Particular aspects of the blocks/steps identified in Figure 1 will depend on both the starting resource and the final fuel product and application (e.g., gasoline and diesel internal combustion engines). They will also vary based on the geographic locations of the resource and the fuel market. Among other things, these locations establish the routes and methods required to transport the various intermediates. The fuel chain scenarios considered in this analysis are:

Scenario 1: FT production from southern Illinois coal for use in the Chicago area

Scenario 2: FT production from Wyoming coal for use in the Chicago area

Scenario 3: FT production from biomass, farmed in southern Illinois, for use in the Chicago area

Scenario 4: FT production from pipeline natural gas, in southern Illinois, for use in the Chicago area

Scenario 5: FT production from Venezuelan natural gas for use in the Chicago area

Scenario 6: FT production from Alaska North Slope natural gas for use in the San Francisco area

These baseline scenarios are assembled from the various FT design, feedstock, transportation and distribution and end-use options analyzed. Sensitivities were considered for some of these scenarios to examine the effect on life-cycle GHG emissions of sequestering CO_2 produced in the FT conversion step, co-producing fuels and power, co-feeding coal and biomass, co-feeding coal and coalbed methane, capturing coalbed methane, and mitigating natural gas venting and flaring. Further in-depth analysis will be required to accurately quantify the more promising of these strategies for reducing GHG emissions. More detailed descriptions of the various blocks shown in Figure 1 are given in Sections 2 through 6 of this report.

2.2 Classification & Characterization

Classification is the process of assigning an inventory result to an appropriate *impact* or *stressor category* and *characterization* involves converting individual results for a category into a *category index* or *equivalency factor*, possibly based on a conceptual environmental mechanism.

The impact categories of primary interest for this study are greenhouse gases (GHG), criteria pollutants (CP), and air toxics. The greenhouse gases considered are: CO_2 (carbon dioxide) from fossil-fuel combustion along the life cycle and venting from natural gas production; CH_4 (methane) from fugitive plant and pipeline emissions, incomplete combustion or incineration (gas flaring), and coalbed methane releases; and N_2O (nitrous oxide) from fuel combustion and the cultivation of biomass feedstocks. Other gases such as chlorofluorcarbons, while extremely potent greenhouse gases, are not used or released in significant quantities from the processes of interest to warrant inclusion in this inventory.

The current interest in greenhouse gases is driven by concerns over the effect that a buildup of these gases in the atmosphere may have on the Earth's climate. The "greenhouse-effect" is proven. The greenhouse gases mentioned above (and others) prevent the sun's radiant energy from being entirely re-radiated back into space as infrared radiation, by absorbing some of this radiation. Human activities in the last two centuries (since the onset of the industrial revolution) have resulted in increasing concentrations of certain greenhouse gases in the atmosphere, thus possibly trapping more solar energy and raising the global average temperature. The effects of such an increase in temperature on the planet can only be predicted by computer simulation. Examining the geological record from previous cycles of planet-wide warming and cooling can give some clues at to what may happen.

While predicting climate change is tremendously complex and many phenomena are still poorly or not understood, efforts have begun worldwide to decrease the rate of increase of GHG emissions. Each greenhouse gas absorbs radiation in a particular set of wavelengths in the spectrum and therefore, individual gases can have very different heat-trapping effects. In order to quantify the heat-trapping effects, assess progress and establish targets, emissions of individual greenhouse gases are characterized into a single metric called the *Global Warming Potential* (GWP). The purpose of the GWP concept is to account for the <u>relative</u> impacts on global warming of various gases compared to carbon dioxide on a weight basis (kg-per-kg). Carbon dioxide, which is the greenhouse gas produced in the largest quantity by the burning of fossil fuels and the least effective greenhouse gas in trapping the Earth's radiant heat, is used as a reference and assigned a GWP of 1.0. The value of a gas's GWP is also a function of the "atmospheric lifetime" or the period of time it would take for natural processes (decomposition or absorption into the ocean or ground) to remove a unit of emissions from the atmosphere. For example, gases such as chloroflurocarbons have lifetimes in hundreds of years whereas carbon monoxide has a lifetime measured in hours or days. Table 1 contains the GWPs recommended by the *Intergovernmental Panel on Climate Change* for the three greenhouse gases of interest in this study: CO_2, CH_4 and N_2O, using three time horizons 20, 100 and 500 years. For example, although methane's atmospheric lifetime is 12 years, its GWP for a 100 year time horizon is still 21 times greater than carbon dioxide; or 10 kg of CH_4 will have a heat-trapping effect equivalent to 210 kg of CO_2 in 100 years. The GWP values for the 100-year time horizon, referred to as *Greenhouse Gas Equivalency Factors*, are used in this study; though, the results could easily be updated to consider other horizons. Examples of these calculations are given in Appendix A.

Table 1: Global Warming Potentials for Selected Gases*
(kg of CO_2 per kg of Gas)

Gas	Lifetime (years)	Direct Effect over Time Horizons of:		
		20 Years	100 Years	500 Years
Carbon Dioxide (CO_2)	Variable	1	1	1
Methane (CH_4)	12 ± 3	56	21	7
Nitrous Oxide (N_2O)	120	280	310	170

*as reported in [6]

Data were also compiled, where possible, for airborne emissions of CO (carbon monoxide), NOx (Nitrogen Oxides), SOx (Sulfur Oxides), VOC (Volatile Organic Compounds), and PM (Particulate Matter). The U.S. EPA classifies these substances as criteria pollutants (CP). At the level of detail of this study, it was not possible to speciate VOCs or further sub-classify PM. There is overlap between the GHG and CP categories. Methane is both a greenhouse gas and a VOC. Other criteria pollutants are believed to participate in global warming; however, the mechanism is not well understood, and they have not been included in the GHG impact category. The only source of CP considered here is combustion. SOx emissions (calculated as SO_2) result from oxidation of sulfur present in fuel. NOx emissions (calculated as NO_2) are the result of both the oxidation of nitrogen in fuel and thermal conversion at high temperatures of N_2 present in combustion air. Emissions of CO, VOC and PM result from incomplete combustion of fuels. PM emissions also result from ash liberated from the fuel during combustion. CP emissions from all combustion sources along the FT fuel chain up to the point of sale of the fuel products have been included in the inventory. CP emissions from end-use combustion of FT fuel are more difficult to analyze, since cars and trucks normally operate under variable loads. Further work will be needed for their incorporation into the LCI.

A checklist was also prepared of compounds used or produced in FT conversion processes, which have been identified by the U.S. EPA as air toxics and hazardous air pollutants (HAPs). Emissions of these substances must be reported to the EPA annually. While these compounds may be released as airborne emissions, no effort has been made to estimate what their emissions might be for the conceptual FT processes studied. Neither have checklists of this kind been developed for the processes upstream and downstream of the FT plant.

No attempt has been made here to characterize individual airborne pollutants as smog precursors, for acidification potential, etc.; or have the results of the inventory been normalized (*normalization* involves dividing an indicator/index by some reference value, commonly the total loading for the given category) or been subject to any valuation (*valuation* involves formalized ranking or weighting to aggregate indicators/indices across multiple categories into a final score). These refinements were considered to be outside the scope of this analysis.

2.3 Impact Allocation

It is standard practice for life-cycle inventory analysis to *allocate* impacts, such as emissions, between the product and various by-products that are generated during the life cycle of the product, though there is some debate on how to actually do this. This procedure, however it might be implemented, is likely to be adequate, if the by-product production rates are relatively small, but this is generally not the case for the energy and fuel systems considered here. Existing petroleum refineries have multiple products, sold for a variety of applications, and future energy systems now being considered may produce electric power in addition to liquid fuels. FT conversion processes also result in a multitude of products, some of which are not used in transportation.

Careful consideration was given to how emissions should be allocated between the various FT fuel products. *For this study, it was decided to allocate emissions from conversion, refining, and all other upstream operations between the LPG, gasoline and distillate fuel products based on the ratio of the energy content (LHV) of the specific fuel relative to the total product*. It is unlikely that more complicated procedures would result in substantially different results, since the energy densities of these liquid fuels are similar. However, this procedure was not considered appropriate when electric power was produced as a major by-product of FT production, since in some sense, power can be considered an end use for all FT fuels produced. To compensate for this, *emissions are allocated to power based on the energy content of the fuel used in the electrical conversion device* (gas or steam turbine); that is, the energy content of the electrical power is divided by turbine efficiency when determining the share of emissions to be allocated to this power. This is similar to the procedure used when calculating the *thermal efficiency* of co-generation (power & steam) processes.

In order to compare the inventory results from the various scenarios considered here, it is necessary to select a *functional unit* to use when reporting results. The functional unit is the production amount that represents the basis of the analysis. This might be gallons of total LPG, gasoline and distillate fuel produced; standard cubic feet of syngas converted; or total energy contained in the products produced. However, it can just as readily be miles of transportation provided or kWh's of electricity delivered. These are services as much as they are tangible products. For the case study reported in Section 7, substitution of FT diesel fuel in diesel-powered SUVs, a *per-vehicle-mile driven* basis was used. Fuel economies in miles-per-gallon (mpg) were used to convert emissions from a per-gallon to a per-mile basis. Since inventory results will change based on the fuel economy used for this conversion, the comparison is specific to SUV conversion from conventional gasoline engines to conventional and advanced diesel engines and is not applicable to passenger cars, heavy-duty trucks, etc. For heavy construction equipment, a better functional unit would be brake horsepower-hr, since this is a measure of the total work being performed.

In general, common English units have been used in the main body of this report. Appendix B gives the results from selected tables in Metric units. The units used to report emissions in the main body of this report are g/ton (MF, moisture free) for coal and biomass production, g/Mscf for natural gas production, g/bbl for FT fuel production and ancillary feedstocks, g/gal for FT fuel transportation, and g/MM Btu for ancillary fuel consumption. For the full inventory reported in Section 7, both g/gal of FT fuel delivered and g/mile driven are reported.

2.4 Inventory Data Issues

Inventory analysis is primarily data driven and results in a database, which is accessed and used in the other phases of LCA. Ideally, one would want these inventory data to be as complete and as accurate as possible, regardless of the scope of any assessment to be performed using these data. This, however, is not often possible, and limitations of the data do impact scope, to varying degrees, for any particular analysis. Data for the inventory can come from measurements done on actual systems or may be the output obtained from process simulation and modeling. Measured data are preferable, but not always available. Both types of data are used here; however, *since the fuel technologies of interest to this study are not widely commercialized* (if at all), *there is a heavy dependence on modeling results and estimated emissions.*

Data collection activities did not involve actual field measurements of emissions. Input data for the inventory were collected from available literature sources and through direct contact with experts in various fields, such as oil tanker transportation, trucking and coal mining. In many instances, the emissions have been estimated either directly by the authors or indirectly by the suppliers of this information. *Special emphasis was placed on estimating the projected emissions from FT process plants.* Emissions from all processes upstream or downstream of the FT conversion plant where compiled from other sources, including a number of other life-cycle emissions inventory analyses conducted by ANL, EIA, EPA, NETL, and NREL. Efforts were made to validate emissions data by comparing data from multiple sources; nevertheless, many inconsistencies remain, and some data are controversial. Data that are missing or considered uncertain have been marked in the appropriate tables as 'na' (not available).

In general, impacts of upstream processes become less significant in the analysis the further one proceeds away from the process of interest (both temporally and spatially), and a trade off becomes apparent between time and effort spent and detail and accuracy of the final inventory. Since the FT processes of interest are still conceptual, little accuracy and relevance are gained by including emissions associated with the manufacture and construction of capital equipment. The minimum useful life of a FT facility would be 20 years or more. However, when considering end-use of the FT fuel, the situation is more complex. The useful life of transportation vehicles, in particular personal automobiles and SUVs, is measured in terms of a few years instead of tens of years, and vehicle replacement and maintenance (such as replacement of tires and engine oil) will impact life-cycle emissions [20]. These effects have been neglected with the caveat that the comparisons made here are between conventional vehicles with similar life expectancies and maintenance requirements and not between radically different vehicle systems (e.g., electric or hydrogen powered vehicles).

In regard to emissions from ancillary resources, the LCI analysis has also been simplified. Upstream emissions from ancillary feeds to the FT fuel chain have either been estimated from available data or, in some cases, completely ignored based on the relative magnitude of the in-flow to the FT fuel chain. Section 6 - *Fuel Combustion, Efficiencies, & Ancillary Emissions* gives explicit information on which emissions have been included for what resources.

Special note must be made relative to the effects of scale. Resources consumed, energy used, and emissions are all functions of the size of the plant being considered, with larger facilities, in general, being more efficient. The FT process designs used here are for plants with nominal capacities of 50,000 bpd of FT product with the exception of the biomass-based conversion plant, which produces only about 1,200 bpd. Care should be exercised when comparing results from cases with widely varying throughputs.

Since only greenhouse gases and criteria pollutants are considered in this study, it has been relatively easy to perform inventory collection and analysis using simple spreadsheet models versus using specialized software packages. Estimating procedures along with sample calculations appear in Appendix A.

3. FISCHER-TROPSCH PROCESS

The Fischer-Tropsch (FT) synthesis was discovered in the 1920s by the German chemists F. Fischer and H. Tropsch. It was briefly used by Germany before and during World War II to produce fuels, and has generated varying levels of interest worldwide since that time. Today, it is used commercially to produce transportation fuels and chemicals at several sites in South Africa, both from coal and natural gas, and at a single site in Malaysia from natural gas. However, there is considerable interest in this technology for the conversion of stranded natural gas reserves into an easily transportable, liquid product.

The FT synthesis involves the catalytic reaction of H_2 (hydrogen) and CO (carbon monoxide) to form hydrocarbon chains of various lengths (CH_4, C_2H_6, C_3H_8,…). A major by-product from the reaction is water. The FT synthesis reaction can be written as:

$$(n/2 + m)\,H_2 \quad + \quad m\,CO \quad \rightarrow \quad C_mH_n \quad + \quad m\,H_2O$$

where m is the average chain length of the hydrocarbons formed, and n equals $2m+2$, if only paraffins are formed, and $2m$, if only olefins are formed. Temperature is one of the main variables affecting the value of m. For iron catalysts, the value of n is intermediate, and a mixture of n-paraffins and n-olefins results with small quantities of n-alcohols also synthesized. Iron has water-gas shift (WGS) activity, which converts much of the water of reaction into CO_2, (carbon dioxide), generating additional H_2. The WGS reactions is:

$$CO \quad + \quad H_2O \quad \leftrightarrow \quad CO_2 \quad + \quad H_2$$

Therefore, synthesis gases with a wide range of H_2 to CO ratios may be used as feed to the FT synthesis, and the WGS reaction can be used to adjust the H_2 to CO ratio to match requirements for hydrocarbon synthesis. Syngas can be produced from coal and biomass by means of gasification. In gasification, oxygen is reacted with the feedstock under conditions which result in partial oxidation (POX) of the feed to form H_2, CO, CO_2, H_2O, CH_4, and small quantities of other hydrocarbon gases. Impurities in coal and biomass also result in the formation of H_2S, NH_3, HCl, and other trace substances that must be removed prior to the FT synthesis. The H_2 to CO ratio for syngas from the coal and biomass gasifiers considered in this study is less than 0.7, and steam is injected into the FT reactor to promote the production of additional H_2 via the WGS reaction.

Synthesis gas derived from natural gas typically has a much higher H_2 to CO ratio than that produced by gasification of coal and biomass, a result of the higher hydrogen content of CH_4 (methane), the primary constituent of natural gas. Natural gas is converted to syngas either by partial oxidation, steam reforming, or a combination of both called autothermal reforming. The exothermic POX reaction of methane is:

$$2\,CH_4 \quad + \quad O_2 \quad \rightarrow \quad 2\,CO \quad + \quad 4\,H_2$$

In the endothermic reforming reaction, oxygen for syngas production is supplied by H_2O (steam) instead of by O_2 from air separation. This reaction is:

$$CH_4 \quad + \quad H_2O \rightarrow \quad CO \quad + \quad 3\,H_2$$

Cobalt catalysts are typically used to convert this high H_2 to CO ratio (~2:1 for POX and ~3:1 for reforming) syngas to hydrocarbons. Cobalt catalysts do not have WGS activity, and water is the primary by-product of the FT synthesis. Paraffins are the dominant hydrocarbon products with only lesser quantities of olefins and alcohols being formed. The H_2 to CO ratio required for the FT synthesis reaction then is $(2m+1)/m$ or $2+1/m$. The H_2 to CO ratio of syngas produced from natural gas can be adjusted to meet this requirement either by externally shifting the syngas or using a combination of POX and steam reforming. If the later is accomplished within a thermally integrated reactor, it is known as autothermal reforming.

The biomass design considered in this study employs an indirectly heated gasification process. The biomass is gasified with steam (reformed) in a fluidized bed of inert sand particles. During this process char is formed. A slipstream of char and sand is removed from the reforming bed and fed to a second fluidized bed where the char is combusted with air. The hot clean sand is then re-circulated to the first bed and provides the necessary heat for the reforming reactions.

The FT reactor considered in this study is a slurry bubble-column reactor. In the slurry bubble column, syngas is bubbled through a suspension of fine catalyst particles. The FT synthesis products distribute between the vapor and liquid phases within the reactor. The lighter hydrocarbons are carried overhead with unreacted syngas, and the heavier components form the molten-wax phase within which the catalyst is suspended. The slurry bubble column is not the only reactor system that can be used for the FT synthesis; fixed catalyst bed and fluid bed systems are used commercially.

The liquid hydrocarbon products from the FT synthesis are of high quality, having negligible sulfur, nitrogen or aromatic impurities and high hydrogen content. They can be transformed into clean-burning transportation fuels by a variety of refining routes. The lighter (lower-boiling) liquid is referred to as naphtha and is a feedstock to a number of processes for producing gasoline-blending components. The heavier (higher boiling) liquid is referred to as distillate. It is generally of sufficient quality to be used directly as a premium diesel fuel, but also may be blended with other distillate fuels to improve their overall quality. The heaviest hydrocarbons formed in the synthesis are a solid wax at ambient conditions and must be cracked to produce liquid products. The lighter C1-C4 gaseous hydrocarbons produced by the synthesis can be recycled back to the syngas generation step or burned in a fired-heater to fulfill plant process heating requirements or in a gas turbine to produce electricity for plant utility requirements (or for sale). C3-C4 hydrocarbons may also be recovered and sold as LPG (Liquefied Petroleum Gas) or converted to high-value gasoline blending components.

3.1 Indirect Liquefaction Baseline Designs

In 1991, Bechtel, along with AMOCO as a major subcontractor, was contracted by the DOE (DE-AC22-91PC90027) to develop conceptual designs, economics and process simulation models for indirect liquefaction based on advanced gasification and Fischer-Tropsch technology. The original focus of these projects was coal liquefaction using two grades of coal, bituminous Illinois No. 6 and subbituminous Powder River Basin. Several design options were also included. The study was later expanded several times to include other design options, primarily related to the upgrading of the FT reactor liquids, and also to consider natural gas based FT synthesis, so-called Gas-To-Liquid (GTL) technology. A final report on this project was issued in April 1998 [7].

Bechtel and its subsidiary, Nexant, Inc., were also contracted to perform other related projects for DOE (DE-AC22-93PC91029). One involved indirect liquefaction of biomass to produce FT liquids and another development of an updated and improved GTL design. Topical reports for these projects were issued in May 1998 [8], and December 2000 (draft) [9].

The Indirect Liquefaction Baseline Design (ILBD) cases developed by Bechtel/AMOCO form the basis for the emissions estimates developed in this report. A description of the design options follows:

Option 1 – Illinois No. 6 Coal with Conventional Product Upgrading (maximum distillate production) [Case 1 from Bechtel report, 7]

Option 2 – Illinois No.6 Coal with Alternate ZSM-5 Product Upgrading (increased gasoline production) [Case 2 from Bechtel report, 7]

Option 3 – Illinois No. 6 Coal with Conventional Product Upgrading (maximum gasoline & chemicals production) [Case 5 from Bechtel report, 7]

Option 4 – Wyoming Powder River Basin Coal with Conventional Product Upgrading (maximum distillate production) [Case 3 from Bechtel report, 7]

Option 5 – Biomass with Conventional Product Upgrading and Once-Through Power Generation [8]

Option 6 – Pipeline Natural Gas with Conventional Product Upgrading (1990 technology - maximum distillate production) [Case 7 from Bechtel report, 7]

Option 7 – Associated Natural Gas with Conventional Product Upgrading (2000 technology - minimum upgrading) [9]

Option 8 – Associated Natural Gas with Conventional Product Upgrading and Once-Through Power Generation (2000 technology - minimum upgrading) [9]

The eight design options listed above differ in a number of significant ways. Five different feedstocks are represented: two coals, Illinois No. 6 bituminous coal (Options 1-3) and Wyoming subbituminous coal (Option 4); biomass, maplewood chips (Option 5); and two natural gas compositions, pipeline specification gas (Option 6) and associated gas from oil production (Options 7 & 8). The coal and biomass based designs employ iron FT catalyst; whereas, the natural gas based designs use cobalt. The Shell gasification process was used in the coal designs, the BCL gasification process in the biomass design, a combination of POX and steam reforming in the pipeline gas design, and autothermal reforming in the associated gas designs. Autothermal reforming is also used in all the coal designs to convert light hydrocarbons (CH_4, C_2H_4, and C_2H_6) back into syngas for recycle to the FT reactor.

The eight design options also differ in the extent and complexity of upgrading used to convert the raw FT reactor liquids to fungible products. Options 1, 4, 5 and 6 all employ conventional refining technology which includes extensive hydroprocessing of the raw liquids. Hydrocracking is used for the conversion of wax to naphtha and distillate. These designs maximize the amount of distillate fuel produced. Option 3 also employs conventional refining technology; however, fluidized-bed catalytic cracking is used for wax conversion. This increases the yield of gasoline relative to distillate fuel and produces propylene for chemical sales. In Option 2, the Mobil ZSM-5 process is employed to directly convert the vapor stream leaving the FT reactor into a premium gasoline blending component. This also increases the yield of gasoline relative to distillate. Options 7 and 8 contain minimal upgrading of the raw FT liquid. Only, hydrocracking is used to convert the wax into additional naphtha and distillate. No other refining is used to upgrade the products. These two designs are more indicative of situations that might arise where the size of the FT plant does not warrant the addition of capital intensive refinery processing, or of locations where the FT product will be shipped to remote markets. Options 5 and 8 also co-produce electric power, which simplifies the overall plant design. Plant location plays a significant factor in all of the designs.

Improvements in process technology are also represented in the design options. The natural gas Options 6, 7 and 8 differ in degree of technology advancement considered. Option 6 is a snapshot of gas-to-liquid technology *circa.*1990. Options 7 and 8 are representative of the state-of-the art in autothermal reforming, FT slurry-bubble column design, cobalt catalyst and hydrocracking technology *circa.* 2000. The remaining designs also represent “older” technology, and it is likely that updated designs would include significant changes to the gasification and FT synthesis processes.

A summary of the design conditions for the eight options considered is given in Table 2.

Table 2: Indirect Liquefaction Baseline Design Data*

Design	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8
Feedstock	IL #6	IL #6	IL #6	Wyo. Coal	Biomass	Pipeline Gas	Assoc. Gas	Assoc. Gas
Upgrading	Maximum Distillate	Increased Gasoline	Maximum Gaso. & Chem.	Maximum Distillate	Fuels & Power	Maximum Distillate	Minimum Upgrading	Min. Upgrading & Power
Raw Materials								
Coal/Biomass/NG (MF ton/day)	18575	18575	18575	19790	2205	8949	13781	13781
Natural Gas (Mscf/day)						412	507	507
Catalysts & Chemicals (ton/day)	342	384	na	394	na	2.92	na	na
Products (bbl/day)								
Methanol			-2303					
Propylene			5060					
LPG	1922	2623	1573	1907	0	1704	0	0
Butanes	-3110	998	-5204	-3101	0	-340	0	0
Gasoline/Naphtha	23943	31255	39722	23756	382	17027	15400	12100
Distillates	24686	15858	9764	24466	775	26211	33800	26700
Products (ton/day)								
Methanol			-321					
Propylene			460					
LPG	171	233	140	169	0	151	0	0
Butanes	-317	102	-531	-316	0	-35	0	0
Gasoline/Naphtha	3021	3904	4988	2997	49	2153	1853	1456
Distillates	3343	2162	1302	3313	105	3542	4548	3586
By-Products								
Slag (MF ton/day)	2244	2244	2244	1747	230			
Sulfur (ton/day)	560	560	560	108				
CO_2 Removal (ton/day)	28444	28414	28463	28325		3270	5114	
CO_2 Carrier Gas (ton/day)	-3715	-3715	-3715	-3958				
S-Plant Flue Gas (ton/day)	1086	1086	1086	348				
Utilities Consumed								
Electric Power (MW)	54.3	53	58	88	-86	-25	0	-372
Raw Water (MM gal/day)	14	14	16	10	2	21	6	4

*Negative products/byproducts are consumed, negative utilities are produced; data from [7-9].

3.2 Process Flowsheet Descriptions

While the design options described in the preceding section differ in details, they can be broken down into four main plant areas: the Syngas Generation Area, which varies based on the nature of the feedstock; the FT Conversion Area, which varies based on the nature of the catalyst; the FT Product Upgrading Area, which varies based on the nature of the final products desired; and Offsite supporting systems. The following sections describe the different process flowsheets developed by Bechtel. The reader not interested in the details of the designs may wish to skip directly to Section 3.2.4

3.2.1 Coal Based Designs

The designs considered in Options 1-4 are all variations on the block flow diagram shown in Figure 2. A breakdown of the various process plants appearing in Option 1 - Illinois No. 6 Coal with Conventional Product Upgrading (maximum distillate production) is given below:

<u>Syngas Generation Area</u>

Coal Receiving & Storage (not shown in Figure 2) - Receives washed coal from mine-mouth coal washing plant, stores the coal in piles, reclaims the coal from storage, and delivers coal to the coal preparation plant.

Coal Preparation - Dries and grinds the coal for use in coal gasifiers.

Air Separation - Provides high-purity (99.5%) oxygen, using cryogenic air separation, for gasification and autothermal reforming of recycle gas.

Gasification - Pressurizes and feeds prepared coal to Shell gasifiers and gasifies coal; includes gas quench, high-temperature gas cooling, slag handling, fly-slag removal and handling, and solid waste handling. CO_2 is used as the carrier gas for the feed coal.

Syngas treatment includes the following three plants:

Syngas Wet Scrubbing - Removes trace amounts of fine particles and humidifies the syngas.

COS Hydrolysis & Gas Cooling - Converts COS to H_2S, HCN to NH_3, and cools the syngas.

Acid Gas Removal - Selectively removes H_2S from the syngas using amine solvent; solvent is regenerated and H_2S-rich gas sent to sulfur recovery.

Sulfur Guard Bed - Removes trace amounts of sulfur compounds, including H_2S, COS and CS_2, using ZnO beds, prior to the syngas entering the FT reactors.

Sulfur Recovery - Receives sour (H_2S-rich) gas streams and converts H_2S to elemental sulfur and any NH_3 to N_2 in a three-stage Claus unit. Tail gas is treated in a SCOT unit prior to discharge through a catalytic incinerator to the stack.

Sour Water Stripping - Strips the water used for syngas wet scrubbing. Wastewater is sent to waste water treatment and the stripped gas to the sulfur plant.

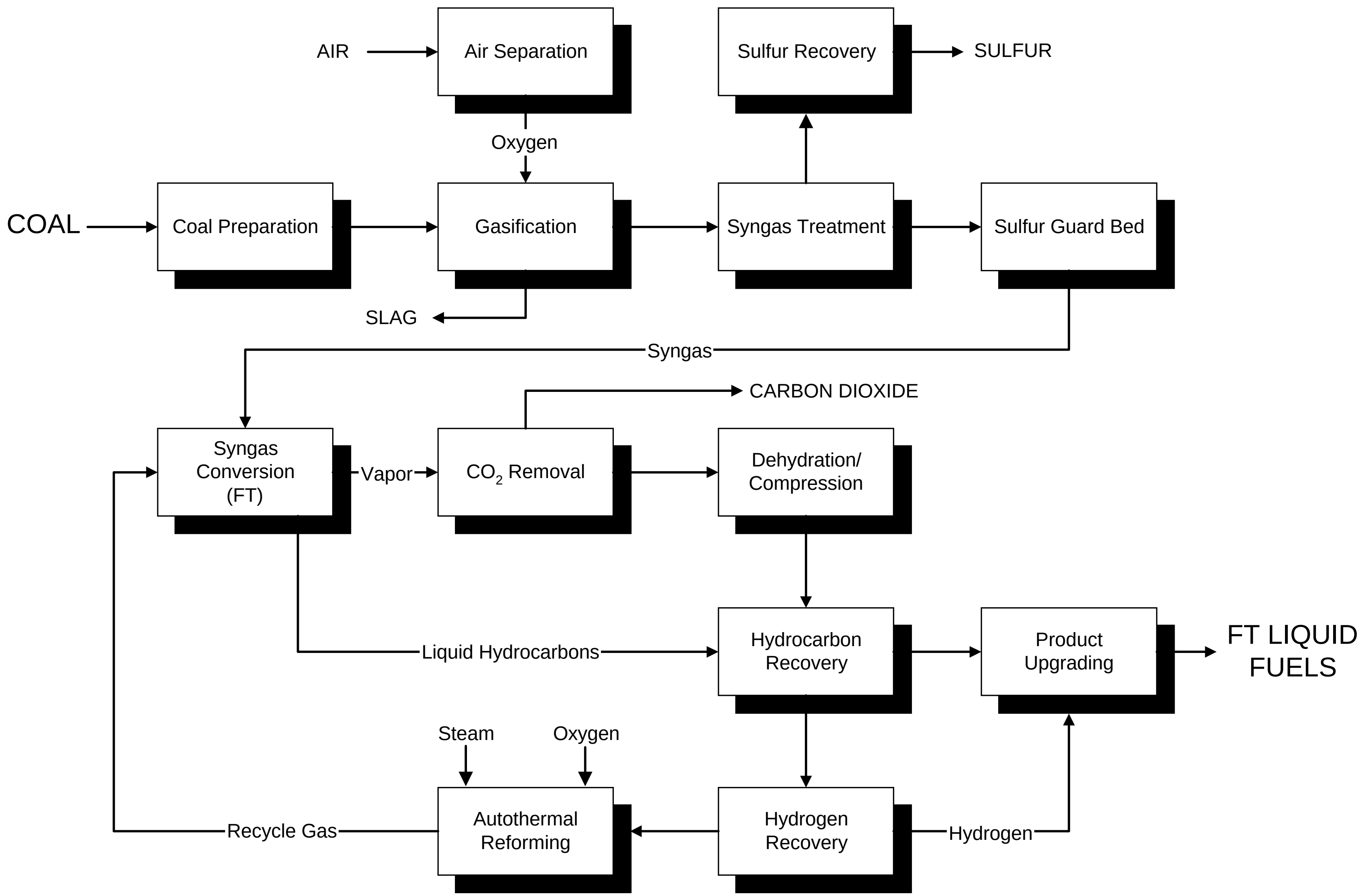


Figure 2. Block Flow Diagram of Coal Liquefaction Process

FT Conversion Area

Syngas Conversion - Converts syngas from the Syngas Generation Area and recycle gas into hydrocarbons using FT slurry bubble-column reactors; includes facilities for pretreatment of the iron FT catalyst, removal of the separate vapor and liquid phases from the reactor, separation and recycle of the catalyst withdrawn with the molten wax phase (physical and supercritical extraction), disposal of spent catalyst, and addition of make-up catalyst.

CO_2 Removal - Selectively removes CO_2 from the FT overhead vapor stream (recycle gas) using proprietary amine (MDEA) solution; includes absorber for contacting the CO_2-rich syngas with CO_2-lean solvent, and stripper for regenerating solvent. A portion of the CO_2 stream is sent to the gasification plant to be used as carrier gas for the coal feed and the remainder is directly vented to the atmosphere.

Dehydration & Compression - Pressurizes and removes moisture from the recycle gas leaving the amine absorber, satisfying the requirements for recycle loop hydraulics and downstream hydrocarbon recovery at low temperatures.

Hydrocarbon Recovery - Recovers C3-C4 hydrocarbons from the recycle gas, using an ethylene/propylene refrigeration cascade, and fractionates hydrocarbon liquids from the FT reactors into naphtha, distillate and molten wax streams.

Hydrogen Recovery - Provides high-purity hydrogen for processes in the FT Product Upgrading Area by means of Pressure Swing Absorption (PSA) of recycle gas and catalytic reformer offgas from FT naphtha upgrading.

Autothermal Reforming - Converts remaining hydrocarbons in the recycle gas (CH_4, C_2H_4, and C_2H_6) back into syngas for recycle to the FT reactors.

FT Product Upgrading Area (details not shown in Figure 2)

Naphtha Hydrotreating - Saturates olefins and removes oxygen from the FT naphtha stream leaving the hydrocarbon recovery plant.

Distillate Hydrotreating - Saturates olefins and removes oxygen from the FT distillate stream leaving the hydrocarbon recovery plant.

Wax Hydrocracking - Saturates olefins, removes oxygen, and cracks the FT wax stream from the FT reactors and hydrocarbon recovery plant, producing additional naphtha and distillate.

C5/C6 Isomerization - Isomerizes n-paraffins in the light naphtha into iso-olefins with improved gasoline-blending properties.

Catalytic Reforming - Converts the remaining heavy naphtha into a highly aromatic gasoline component with improved blending properties, and generates a medium-purity hydrogen offgas.

C4 Isomerization - Isomerizes n-butane from the FT synthesis and supplemental, purchased n-butane to isobutane for alkylation.

C3/C4/C5 Alkylation - Synthesizes additional high-quality gasoline blendstock from isobutane and C3/C4/C5 olefins from the FT process.

Saturate Gas Plant - Processes and separates offgas from various sources within the FT Product Upgrading Area producing LPG for sale, butanes for isomerization/alkylation and additional plant fuel gas.

<u>Offsites</u> (not shown in Figure 2)

Relief & Blowdown - Collection and flaring of relief and blowdown discharges from all applicable plants; includes two flare systems, one for hydrocarbon containing discharges and a secondary flare for discharges containing H_2S.

Tankage - Storage and delivery of products, intermediates and chemicals.

Interconnected Piping System - Includes process and utility piping between process plants and offsites.

Product Shipping - Provides the pipeline and metering system for the delivery of final FT naphtha and distillate products to customers.

Tank Car/Truck Loading - Provides pumping and loading/off-loading facilities for by-products (propane and sulfur) shipped and catalysts and chemicals received by tank car or tank truck.

Coal Ash Disposal - Transports coal ash and slag via conveyor back to coal mine for disposal as land reclamation.

Catalyst & Chemicals Handling - Provides storage and handling for catalysts and chemicals used in all plants.

Electrical Distribution System - Receives power from across-the-fence utility substations and distributes electricity to all applicable plants.

Steam & Power Generation - Manages and distributes all steam used and generated in all applicable plants and provides for excess steam for on-site power generation.

Raw, Cooling & Potable Water - Provides water treatment for make-up water withdrawn form nearby lakes or rivers, and distributes cooling and potable water to all applicable plants; includes cooling tower.

Fire Protection System - Provides fire protection and control systems for all facilities, structures and equipment.

Sewage & Effluent Water Treatment - Treats all wastewaters, including coal storage pile runoff, oily wastewater, process wastewater, solids de-watering and sanitary sewage.

Instrument & Plant Air Facilities - Provides instrument and utility air to all applicable plants and support facilities.

Purge & Flush Oil System - Delivers light and heavy flush oil for pump seal flushing and instrument purging.

Solid Waste Management - Disposes of wastes from raw, cooling and potable wastewater treatment.

General Site Preparation - Leveling and grading greenfield construction site; includes improvements such as roads, fencing, drainage, and placement of load-bearing fills, pilings and building foundations.

Buildings - Construction of all facilities onsite.

Telecommunications Systems - Provides telecommunications services for construction and operation of facility.

Distributed Control Systems - Provides control systems for monitoring and operating all applicable plant operations.

Options 2-4 involve variations of this basic design. For Option 2 - Illinois No. 6 Coal with Alternate ZSM-5 Product Upgrading, the following modifications are included:

Syngas Conversion - ZSM-5 reactors are provided directly downstream of the FT reactors to convert all overhead product leaving the FT reactors into a premium gasoline blending component. In turn, this simplifies the design of the FT Product Upgrading Area. *Naphtha Hydrotreating, Distillate Hydrotreating C5/C6 Isomerization, and Catalytic Reforming* processes are not required.

The only modifications to the basic design required for Option 3 - Illinois No. 6 Coal with Conventional Product Upgrading (maximum gasoline & chemicals production) are in the FT Product Upgrading Area. *Wax Hydrocracking* is not included, and the following processes have been added:

Fluid Catalytic Cracking - Cracks the FT wax stream from the FT reactors and hydrocarbon recovery plant, producing additional naphtha, light olefins for alkylation and ether synthesis, and a small quantity of distillate.

Ether Synthesis - Synthesizes gasoline blending ethers from C4 and higher iso-olefins using MTBE and TAME process units.

Only plant-specific modifications and changes to operating conditions (primarily in the Syngas Generation Area) are required for Option 4 - Wyoming Powder River Basin Coal with Conventional Product Upgrading:

Acid Gas Removal - Because of the high CO_2/H_2S ratio in the syngas, the amine absorption system is replaced with a Rectisol (methanol) wash system.

Raw, Cooling & Potable Water - This plant was redesigned by Bechtel for zero discharge to conserve water usage in an arid climate (Wyoming).

3.2.2 Biomass Based Design

The design considered in Option 5 - Biomass with Conventional Product Upgrading and Once-Through Power Generation is shown in the block flow diagram in Figure 3. This design is for a much smaller plant having only a single gasification train and only producing 1,156 bpd of FT liquid products versus the roughly 50,000 bpd produced in the previous designs. A breakdown of the various process plants appearing in the biomass design that differ from Option 1 is given below:

<u>Syngas Generation Area</u>

Wood Receiving & Storage (not shown in Figure 3) - Replaces coal receiving and storage.

Wood Preparation - Replaces coal preparation; dries wood chips prior to gasification.

Indirect Gasification - Feeds dried wood chips to a low-pressure, indirectly heated gasifier for gasification; includes char combustor and sand recirculation loop.

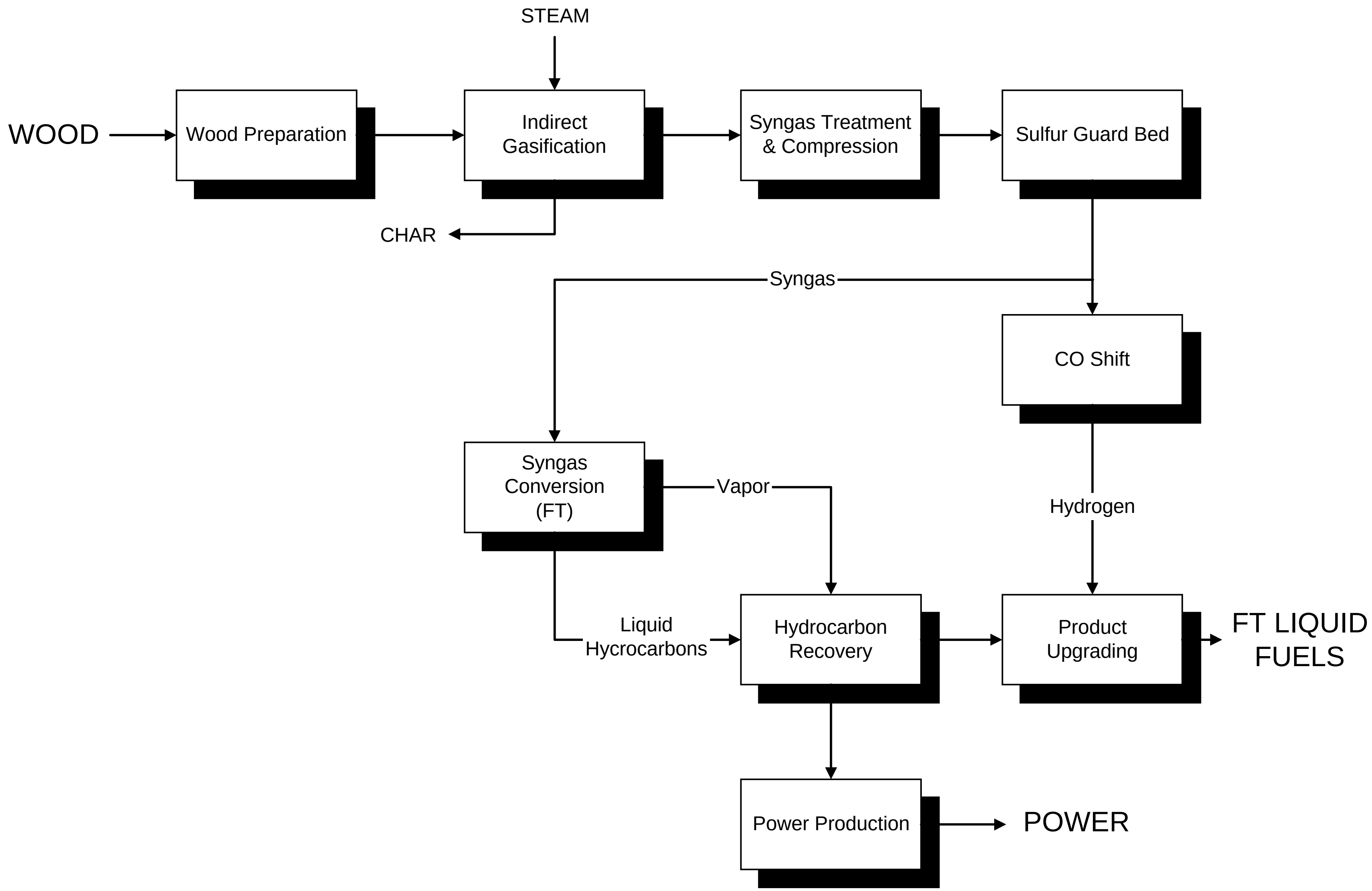


Figure 3. Block Flow Diagram of Biomass Liquefaction Process

Syngas Treatment & Compression - Washes and cools syngas in a spray column before compressing syngas up to pressures required for FT synthesis and power generation.

CO Shift - Produces and purifies hydrogen from treated syngas used for FT product upgrading.

The *Sulfur Guard Bed* is still required to remove trace amounts of sulfur compounds from the syngas (small amounts of sulfur are present in the biomass feed). *Air Separation, Syngas Wet Scrubbing, COS Hydrolysis & Gas Cooling, Acid Gas Removal, Sulfur Recovery, and Sour Water Stripping* are not required.

<u>FT Conversion Area</u>

Syngas Conversion - FT reactors and catalyst systems remain unchanged.

Hydrocarbon Recovery - Cryogenic design has been replaced with a non-cryogenic system, which recovers only C5+ hydrocarbons and fractionates hydrocarbon liquids into naphtha, distillate and wax streams. Lighter hydrocarbons are used as fuel gas.

CO_2 Removal, Dehydration & Compression, Hydrogen Recovery, and Autothermal Reforming are not required.

<u>FT Product Upgrading</u>

Naphtha Hydrotreating, Distillate Hydrotreating, Wax Hydrocracking, C5/C6 Isomerization, and Catalytic Reforming are still included for product upgrading. *C4 Isomerization, C3/C4/C5 Alkylation, and Saturate Gas Plant* are not required, since light hydrocarbons are used for fuel in this design.

<u>Offsites</u>

Combined-Cycle Power Plant - Consumes all the excess fuel gas produced by the facility to generate electric power for sale.

Bechtel did not redesign any other offsite facilities for this option. Rather, they assumed these would remain approximately the same and prorated requirements using design Option 1.

3.2.3 Natural Gas Based Designs

The design considered in Option 6 – Pipeline Natural Gas with Conventional Product Upgrading (1990 technology - maximum distillate production) is shown in the block flow diagram in Figure 4. This design is very similar to Option 1.

A breakdown of the various process plants appearing in this natural gas design that differ from Option 1 is given below:

<u>Syngas Generation Area</u>

Natural gas is supplied by pipeline.

Air Separation - Provides high-purity (99.5%) oxygen for POX using cryogenic air separation.

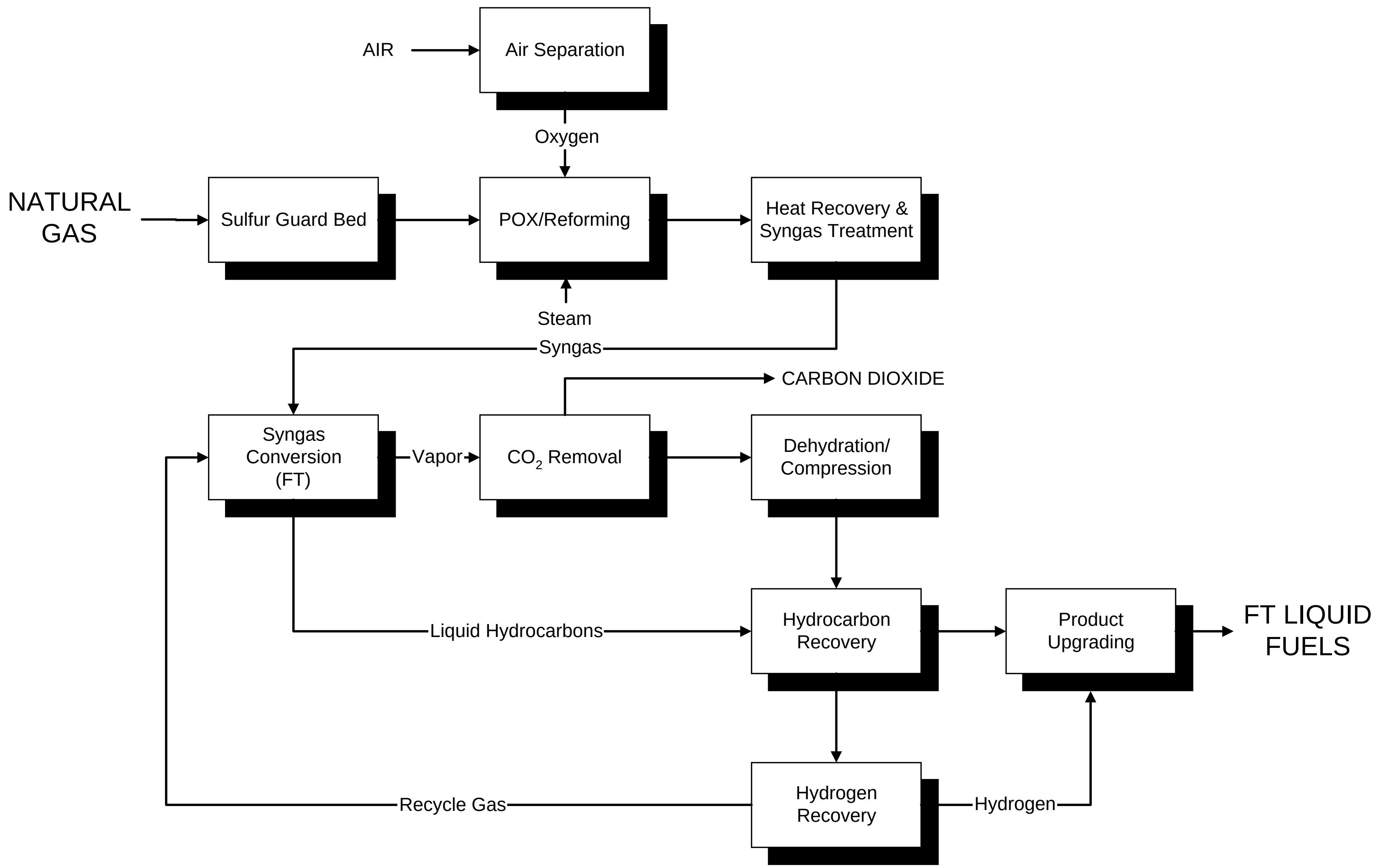


Figure 4. Block Flow Diagram of Gas-To-Liquid Process - Old Design

Sulfur Guard Bed - Removes trace amounts of sulfur compounds from the natural gas prior to the POX and steam reforming reactors.

POX/Reforming includes parallel trains of these units to achieve desired H_2 to CO ratio for FT synthesis:

POX - Partially oxidizes natural gas to syngas using oxygen form the air separation plant.

Steam Reforming - Catalytically reforms natural gas to syngas using steam.

Heat Recovery & Syngas Treatment - Recovers heat and scrubs traces of particulates from the cooled syngas.

Syngas Wet Scrubbing, COS Hydrolysis & Gas Cooling, Acid Gas Removal, Sulfur Recovery, and Sour Water Stripping are not required.

FT Conversion Area

Syngas Conversion - Converts syngas from the Syngas Generation Area and recycle gas into hydrocarbons using two-stage FT slurry bubble-column reactor system with interstage hydrocarbon removal from the overhead gas; includes facilities for pretreatment of the cobalt FT catalyst, removal of the separate vapor and liquid phases from the reactor, separation and recycle of the catalyst withdrawn with the molten wax phase (physical separation), disposal of spent catalyst, and addition of make-up catalyst.

CO_2 Removal, Dehydration & Compression, Hydrocarbon Recovery, and Hydrogen Recovery are still required. *Autothermal Reforming* of the recycle gas is not included.

FT Product Upgrading

Upgrading is identical to Option 1.

Offsites

Bechtel did not redesign the offsite facilities for this case. Again, they assumed these would remain approximately the same and prorated requirements using design Option 1. All offsites that are required solely due to coal handling and processing operations have been excluded.

The designs considered in Option 7 – Associated Natural Gas with Conventional Product (2000 technology - minimum upgrading) and Option 8 – Associated Natural Gas with Conventional Product Upgrading and Once-Through Power Generation Product (2000 technology - minimum upgrading) are variations of the block flow diagram shown in Figure 5. A breakdown of the various process plants appearing in these natural gas designs is given below:

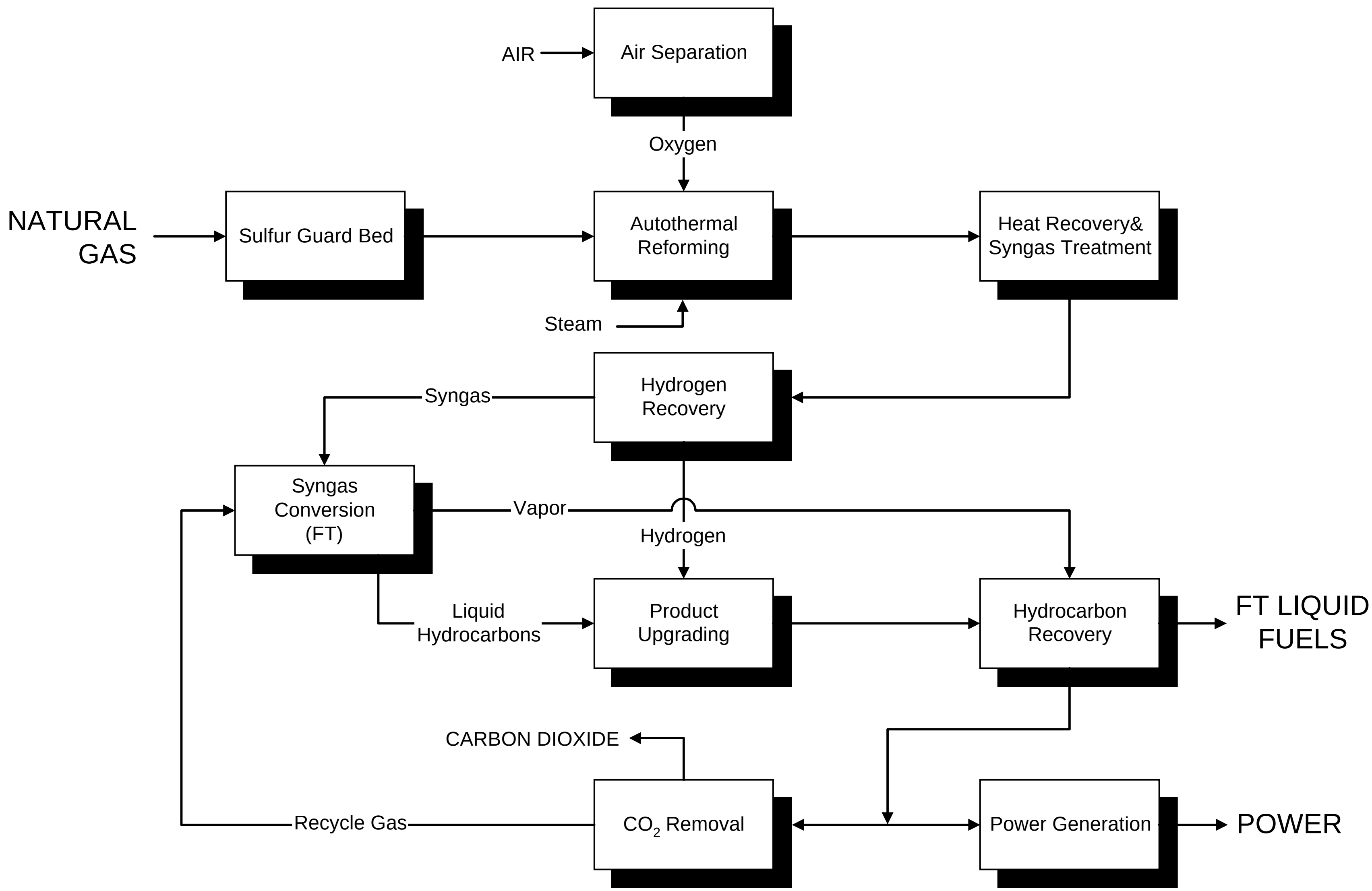


Figure 5. Block Flow Diagram of Gas-To-Liquid Process - New Design

Syngas Generation Area

Natural gas feed is *associated gas* from oil field production, which has been processed in an upstream gas processing plant to remove sour gas (H_2S), some natural gas liquids (C4s) and all natural gasoline (C5+ liquids). It contains significant amounts of CO_2. *Autothermal Reforming* replaces combined *POX/Reforming* to achieve desired H_2 to CO ratio for FT synthesis; requires both oxygen and steam. *Hydrogen Recovery* has been moved upstream of the FT reactors. All remaining processes are the same as in Option 6.

FT Conversion Area

Syngas Conversion - Converts syngas from the Syngas Generation Area and recycle gas into hydrocarbons using redesigned single-stage FT slurry bubble-column reactor system with cobalt FT catalyst.

Hydrocarbon Recovery - Coal design has been replaced with a non-cryogenic system, which recovers only C5+ hydrocarbons and fractionates hydrocarbon liquids into naphtha, distillate and wax streams. Lighter hydrocarbons are used as fuel gas.

CO_2 Removal has been moved to the syngas recycle loop in Option 7. *CO_2 Removal* and *Dehydration & Compression* are not required in Option 8, where unconverted syngas and C4- hydrocarbons are being used to generate electric power for sale.

FT Product Upgrading

Product upgrading has been significantly simplified (minimal upgrading case) and only includes:

Wax Hydrocracking - Cracks the FT wax stream from the FT reactors and hydrocarbon recovery plant producing additional naphtha and distillate, transportable by conventional oil transportation systems, tankers and pipelines.

Offsites

Combined-Cycle Power Plant - Consumes all the excess syngas/fuel gas produced by the facility to generate electric power for sale.

3.2.4 Resource Consumption & Yields

The various designs described in the preceding sections differ in their degree of detail. While the early designs completed by Bechtel were based on detailed sizing and costing [10-13], later designs were based on Aspen process simulation models developed primarily to fit the original designs (with modifications for the different technology options under consideration) [8,14,15]. For all the designs, however, material and energy balances were reported, which allow emissions to be calculated. In no case were these FT plant designs rigorously optimized, either for return on economic investment or to minimize emissions. They represent, as a group, the best-expected practices for these technologies at the time of their design.

Material and energy balance data from the eight designs being considered in this LCI were used to generate the resource consumption and yield data presented in Table 3. The basis for these values is 1 bbl of FT C3+ liquid product (combined C3/C4 LPG plus gasoline/naphtha plus distillate) unless noted. Yields are presented on a volume basis (bbl/bbl FT C3+ products), a mass basis (ton/bbl), and an energy basis (MM Btu (LHV)/bbl). The thermal efficiencies (LHV basis) of the coal and biomass liquefaction designs range from 47-52%. The thermal efficiencies of the natural gas designs are somewhat higher at 57-59%. The carbon efficiencies of the coal and biomass designs range from 37-41%. The carbon efficiency for the pipeline natural gas design is 57% and for both associated natural gas designs is about 39%. The large difference between the natural gas designs is due to the 13% CO_2 in the associated gas.

In addition to the primary feedstocks (coal, biomass or natural gas), the conversion plants require ancillary feedstocks: butanes and methanol used in specific FT product upgrading steps, raw water make-up (e.g., river water), catalysts and chemicals, and in some cases purchased supplemental electric power. Catalysts and chemicals have been aggregated to show that the amounts of these materials used are small relative to the primary feedstocks (1-2 wt%). Emissions associated with the production and delivery of catalysts and chemicals to the FT plant have been ignored for the LCI.

In the designs without recycle (Options 5 and 8), considerable power is generated and sold. Emissions and resource consumption have been allocated to the power, based on thermal input to the power generation device (gas or steam turbine). Option 6 also generates a small amount of power, which is sold to the electric grid. The fractions of all resources, by-products or emissions allocated to the fuels products are listed in Table 3. These allocations are 32.6%, 97.4% and 79.0% for Options 5, 6 and 8, respectively. Option 5 primarily produces power from biomass gasification; a result of the high methane content of the syngas produced by the low-temperature BCL gasifier. This methane is not directly available for conversion to higher hydrocarbons by the FT synthesis, and would require the addition of a steam reforming step to produce additional syngas. Allocations to power produced, on a per kWh basis, are listed in Table 3 in square brackets.

Table 3: Resource Consumption and Yields for FT Production

(Per bbl of FT Liquid Product)

Design	Option 1	Option 2	Option 3	Option 4	Option 5[1]	Option 6[1]	Option 7	Option 8[1]
Feedstock	IL #6	IL #6	IL #6	Wyo. Coal	Biomass	Pipeline Gas	Assoc. Gas	Assoc. Gas
Upgrading	Maximum Distillate	Increased Gasoline	Maximum Gaso. & Chem.	Maximum Distillate	Fuels & Power	Maximum Distillate	Minimum Upgrading	Min. Upgrading & Power
Resources								
Coal or Biomass (MF ton)	0.3675	0.3661	0.3310	0.395	0.621 [0.00072]			
Natural Gas (Mscf)						8.927 [0.018]	10.305	10.325 [0.012]
Butanes (bbl)	0.062		0.093	0.062		0.008		
Methanol (bbl)			0.041					
Catalysts & Chemicals (lb)	13.52	15.44	na	15.71	na	0.13	na	na
Water Make-Up (gal)	286	285	279	196	541 [0.629]	455 [0.923]	114	91 [0.105]
Electric Power (kWh)[2]	25.79	24.87	24.87	42.12	-1781	-13.2		-230
Volume Yield (bbl)								
C3/C4 LPG	0.038	0.071	0.118	0.038		0.038		
Gasoline/Naphtha	0.474	0.616	0.708	0.474	0.330	0.379	0.313	0.312
Distillates	0.488	0.313	0.174	0.488	0.670	0.583	0.687	0.688
Mass Yield (ton)								
C3/C4 LPG	0.003	0.007	0.011	0.003		0.003		
Gasoline/Naphtha	0.060	0.077	0.089	0.060	0.042	0.048	0.038	0.038
Distillates	0.066	0.043	0.023	0.066	0.091	0.079	0.092	0.092
Slag (MF)	0.044	0.044	0.040	0.035	0.065			
Sulfur	0.011	0.011	0.010	0.002				
Energy Yield (MMBtu)								
C3/C4 LPG	0.135	0.262	0.422	0.134		0.134		
Gasoline/Naphtha	2.120	2.764	3.019	2.121	1.463	1.687	1.439	1.433
Distillates	2.500	1.611	0.862	2.498	3.427	2.979	3.495	3.494
Power [3]					10.128	0.128		1.309
Allocation to Fuels					32.6%	97.4%		79.0%
Thermal Efficiency (LHV)	50.4%	52.0%	47.4%	49.3%	51.0%	59.1%	57.3%	57.1%
Carbon Efficiency	40.1%	41.1%	37.7%	39.1%	37.2%	57.0%	39.3%	39.2%

1 Values in [ ] are allocations per kWh of electricity produced and sold. All other values are per bbl of FT liquid product.

2 Positive value is purchase, negative value is sale.

3 Energy content of fuel used to produce power for sale.

In addition to the primary FT liquid products, ancillary products are also produced. These include elemental sulfur and slag for the coal-based designs (Options 1-4). Sulfur is sold as a by-product; however, no emissions have been allocated to it. Slag is returned to the coal mine for land reclamation. The biomass design (Option 5) produces a char/sand mixture from the gasifier, which could conceivably be sold for road asphalt manufacture. Again, emissions have not been allocated to slag or char. Wastewater discharges are not a significant issue for an inventory of airborne emissions and have not been included in Table 3. They are significant outflows from the Illinois sited FT plants (Options 1-3, 5 and 6). The Wyoming sited F-T plant (Option 4) was designed for zero water discharge.

3.3 Emissions from FT Production

Air emissions are generated from several sources within a FT conversion plant: combustion, vents, and fugitive sources. The conceptual designs developed by Bechtel meet all applicable federal and state (Illinois & Wyoming) statutes at the time of the design for airborne emissions of SOx, NOx, CO, VOC, and PM, including U.S. EPA New Source Performance Standards (NSPS).

Combustion emissions are associated with the burning of fuels within the plant. The primary fuel used in the FT designs is fuel gas generated in the FT Conversion Area (purged recycle gas) and the FT Product Upgrading Area (offgas). This fuel gas is a medium-Btu gas (300-400 Btu/scf) containing H_2, CO, and C1-C4 hydrocarbons. Fuel gas is used in fired heaters to provide process heat, in boilers to raise steam and in gas turbines to generate electric power. CO_2 emissions from fuel gas combustion were calculated from a carbon balance around the FT plant. For the other combustion related emissions, factors compiled by the EPA for refinery fuel gas were employed (see Section 6). The accuracy of this calculation is uncertain, since refinery fuel gas is a high-Btu gas (1000+ Btu/scf) rich in C1-C4 hydrocarbons. Different burner designs for these fuels will affect relative emissions of criteria pollutants. Gas turbine emissions of CH_4, CO and VOCs are generally higher than those from fuel gas combustion in a fired heater or boiler, and NOx emissions are generally lower [20]. Since the bulk of the fuel gas is used in fired heaters and boilers, adjustments to these emissions have not been made. For Option 5, where biomass is gasified in an indirectly heated gasifier, biomass char is burned in a fluidized bed combustor. Significant emissions are expected from this source. When catalysts are periodically or continuously regenerated (e.g., fluid catalytic cracking in Option 3) similar emissions can occur. Insufficient information was available to estimate emissions from these sources. However, they may be significant sources, particularly of NOx, CO and PM emissions.

Incineration is also a source of combustion emissions. The FT plant designs include a flare system for combustion of offgas produced during the normal operation of the plant and during start-up, shutdown, and process upsets. Flare emissions of methane have been estimated based on data for U.S. refineries (5.5 g CH_4 per refined bbl) [21]. It was assumed that the FT plant is of the same degree of complexity as an average U.S. refinery but has been designed to minimize flaring and, therefore, emissions are only half those reported for the average U.S. refinery. This seems reasonable for Options 1-6, where FT product upgrading includes many major refinery processes. For the associated gas Options 7 and 8, minimal refinery upgrading has been included, and it has been further assumed that emissions might be half of those expected from the other designs. Options 1-4 include a sulfur recovery plant, which generates a tail gas stream containing trace amounts of volatile sulfur compounds (H_2S and COS). This stream is catalytically combusted and sent to a separate flare. SOx emissions have been estimated based on the reported composition of this stream.

Vent emissions are point source emissions from the direct venting of process and utility streams to the atmosphere. The most significant stream in this category, and the only one included in this inventory, is the high-purity CO_2 stream vented from the CO_2 removal plant. This is the major source of the GHG emissions from the FT conversion process.

Fugitive emissions are releases from leaking equipment (valves, pumps, etc.), storage tanks and waste water treatment facilities. Since the FT plant designs are for state-of-the art facilities, they have been designed to minimize fugitive emissions of criteria pollutants. Fugitive emissions of CH_4 have been estimated based on data for U.S. refineries. For state-of-the art FT conversion facilities, it has been assumed that these emissions are only half those reported for the average U.S. refinery (231 g CH_4 per refined bbl). Emissions of CO_2 are not currently regulated, and roughly 1% of the CO_2 generated in the FT process is emitted from fugitive sources, primarily wastewater treatment operations.

3.3.1 Emissions Inventory for FT Production

Table 4 contains the LCI for the conversion step in the FT fuel chain for the eight FT plant designs considered in this study. Emission sources included in the inventory are fuel gas combustion, incineration, flaring, direct and indirect venting of CO_2, and upstream emissions from all ancillary feedstocks to the processes. The emission factors used to estimate these emissions and sample calculations are given in Appendix A. Ancillary emissions are presented in Section 6.

The clear trend in Table 4 is that most emissions are higher for the coal and biomass designs relative to the gas-to-liquid designs. All of the coal-based designs purchase supplemental electric power, and emissions from upstream electricity generation account for much of the difference for criteria pollutants. Coal also contains significant levels of sulfur, which is removed at the liquefaction plant. Tail gas from this process accounts for some of the SOx emissions for these designs; however, the bulk of SOx emissions are from ancillary power generation. The natural gas and biomass feedstocks contain only trace amounts of sulfur, and no bulk removal of sulfur compounds from the syngas is required. However, wellhead gas can contain significant amounts of H_2S, which would be removed in a gas processing plant upstream of a GTL facility. The SOx emissions listed for Option 6 are ancillary emissions related to the production of butanes used in the FT upgrading step.

Options 5 and 8 require special comment. Both produce significant excess power for sale. In this study, emissions were allocated between power and fuels in order to make comparisons between different design options. Table 5 contains the emissions for Options 5, 6 and 8 allocated to power on a per kWh of electricity produced and sold. *The procedure used for this allocation has a significant effect on the reported emissions per bbl of fuel produced*. This uncertainty is compounded by a lack of detailed information on fuel gas generation and consumption for some of the FT plant designs. Therefore, caution should be exercised when comparing the emissions from biomass liquefaction to coal liquefaction or to emissions from the various natural gas designs. Further work is needed to validate any benefits of co-producing fuels and power.

Table 4: Emissions Inventory for FT Production
(Per bbl of FT Liquid Product)

Design	Option 1	Option 2	Option 3	Option 4	Option 5*	Option 6*	Option 7	Option 8*
Feedstock	IL #6	IL #6	IL #6	Wyo. Coal	Biomass	Pipeline Gas	Assoc. Gas	Assoc. Gas
Upgrading	Maximum Distillate	Increased Gasoline	Maximum Gaso. & Chem.	Maximum Distillate	Fuels & Power	Maximum Distillate	Minimum Upgrading	Min. Upgrading & Power
CO_2 (g)	534311	526684	507159	575203	706987	119687	210964	92978
CH_4 (g)	58.55	51.14	64.40	87.27	12.97	8.45	4.77	4.79
N_2O (g)	2.16	1.91	2.11	2.85	16.50	1.60	2.02	3.17
SOx (g)	197.64	190.73	193.85	298.04	0	0.06	0	0
NOx (g)	89.08	72.07	98.31	118.82	523.90	51.93	64.15	100.51
CO (g)	15.66	11.73	18.02	19.09	127.23	12.61	15.58	24.41
VOC (g)	61.40	46.19	76.21	91.05	22.45	3.77	2.75	4.31
PM (g)	50.40	48.10	49.53	81.60	11.23	1.14	1.37	2.15

*Values reported only include allocation to fuel products.

Table 5: Emissions Inventory for Power Exported from FT Plants
(Per kWh of Electric Power)

Design	Option 5*	Option 6*	Option 8*
Feedstock	Biomass	Pipeline Gas	Assoc. Gas
Upgrading	Fuels & Power	Maximum Distillate	Min. Upgrading & Power
CO_2 (g)	822	243	107
CH_4 (g)	0.015	0.017	0.006
N_2O (g)	0.019	0.003	0.004
SOx (g)	0.000	0.000	0.000
NOx (g)	0.609	0.105	0.116
CO (g)	0.148	0.026	0.028
VOC (g)	0.026	0.008	0.005
PM (g)	0.013	0.002	0.002

*Values reported only include allocation to exported power.

3.3.2 Greenhouse Gases Emissions from FT Production

Greenhouse gas emissions for the FT designs have been compiled separately in Table 6. Emissions of CH_4 and N_2O have been converted to CO_2 equivalents using the GWPs in Table 1 for a 100-year time horizon. The GHG emissions in Table 6 have been broken up into the categories of vented gas, combustion and incineration flue gas, fugitive emissions and flaring, and ancillary emissions. GHG emissions are clearly dominated by direct CO_2 emissions; CH_4 and N_2O emissions account for less than 1% of total GHG emissions from the FT plants.

For the coal-based designs, the largest single source of GHG emissions is CO_2 removal (vented gas), followed by combustion of flue gas. Incineration flue gas and ancillary emissions are of roughly the same magnitude for the Illinois No. 6 coal designs. Incineration flue gas emissions are much smaller for the Powder River Basin coal. This is due to the higher sulfur content of Illinois coal versus Wyoming coal, which results in a larger gas stream being incinerated. However, overall GHG emissions are higher for the Wyoming coal and the biomass designs. This results from the high oxygen contents of these feedstocks (44 wt% for biomass and 17% for Wyoming subbituminous coal vs. 8% for Illinois #6 bituminous coal).

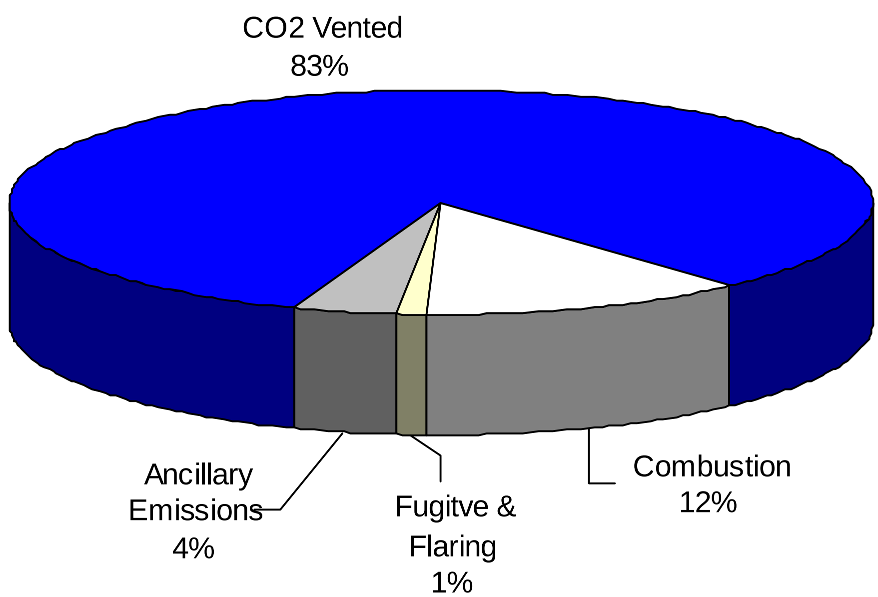
Table 6: GHG Emissions from FT Production
(Per bbl of FT Liquid Product)

Design	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5***	**Option 6***	**Option 7**	**Option 8***
Feedstock	IL #6	IL #6	IL #6	Wyo. Coal	Biomass	Pipeline Gas	Assoc. Gas	Assoc. Gas
Upgrading	Maximum Distillate	Increased Gasoline	Maximum Gaso. & Chem.	Maximum Distillate	Fuels & Power	Maximum Distillate	Minimum Upgrading	Min. Upgrading & Power
CO_2 – vented gas (g)	443800	441652	400060	440972	0	64289	94294	0
CO_2 – combustion flue gas (g)	47685	44538	65931	92081	706987	54565	115726	92978
CO_2 – incineration flue gas (g)	17803	17739	16037	5493	0	0	0	0
CO_2 – fugitive emissions (g)	5105	5081	4601	5126	0	643	943	0
CO_2 – ancillary sources (g)	19917	17675	20530	31531	0	191	0	0
CH_4 – combustion flue gas (g CO_2-eq)	15	12	14	15	225	22	28	43
CH_4 – fugitive & flaring (g CO_2-eq)	145	145	145	145	47	141	73	57
CH_4 – ancillary sources (g CO_2-eq)	1070	917	1193	1673	0	14	0	0
N_2O – combustion flue gas (g CO_2-eq)	331	266	328	334	5115	497	626	981
N_2O – ancillary (g CO_2-eq)	337	325	327	551	0	0	0	0
Total (g CO_2-eq)	536209	528350	509166	577921	712374	120361	211690	94060

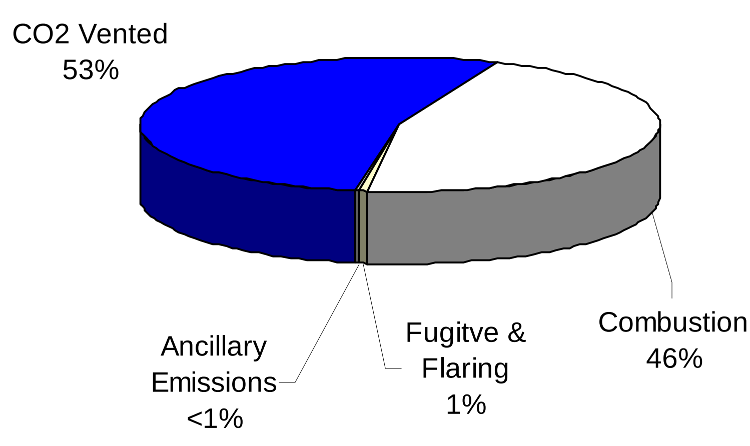
* Values reported only include allocation to fuel products.

Natural gas, which is rich in hydrogen, does not produce as large a quantity of CO_2 during FT conversion (as can be seen by comparing the carbon efficiencies given in Table 3 for Option 6); and thus, has much lower GHG emissions than those from coal and biomass. Figure 6 clearly shows this effect for Options 1 and 6, which use different feedstocks (coal and natural gas) but produce the same FT products. Vented emissions of CO_2 are a smaller fraction of total GHG emissions for this natural gas design. This observation correlates well with the efficiencies of the two processes, 50% and 59% for Options 1 and 6, respectively. The large difference in GHG emissions between Options 6 and 7 is attributed to the high CO_2 content of the associated gas (13 vol%) versus the pipeline natural gas (less than 1%). There may be other small effects from the differences in the basic process designs. Option 8 would seem to indicate that GHG emissions could be greatly reduced by co-producing power. As was mentioned earlier, this may be an artifact of the allocation procedure used and requires further analysis. The fuels and power co-production designs do not contain a CO_2 removal step. Therefore, all CO_2 generated during the syngas generation and FT conversion steps is exhausted in the combustion flue gas streams.

No great differences exist between the emissions from the alternative upgrading Options 1, 2 and 3. Therefore, Option 1 will be used as the basis for Scenario 1 in the full GHG emissions inventory given in Section 7. Option 4, Wyoming coal, is the basis for Scenario 2; Option 5, biomass conversion, is the basis for Scenario 3; and Option 6, pipeline gas conversion, is the basis for Scenario 4. Option 7 is the basis for both Scenarios 5 and 6, which involve the conversion of stranded natural gas associated with oil production. Option 8 is used as the basis for the estimates made in the sensitivity analysis in Section 7.3 for the effects of co-production on GHG emissions.



Design Option 1
536,209 g CO_2 -eq/bbl FT Product



Design Option 6
120,362 g CO_2-eq/bbl FT Product

Figure 6. Comparison of GHG Emissions Sources for FT Production

3.3.3 Air Toxics Checklist for FT Production

Some of the emissions that would arise from leaking equipment and process vents in FT plants are air toxics and hazardous air pollutants (HAPs). Releases of these compounds must be reported annually to the U.S. EPA. A checklist (Table 7) was compiled of compounds requiring reporting that are used or produced in FT plants, based on the conceptual designs described previously. Table 7 identifies which designs are affected and the possible sources of these compounds within the plant. While these compounds may be released as airborne emissions, no effort has been made to estimate what their emissions might be in an operating FT conversion facility. As stated previously, if these plants are built, they are likely to include state-of-the-art pollution control equipment, minimizing both fugitive and vent emissions.

Table 7: Air Toxics Checklist for FT Production

Chemical	Syngas Generation Area	FT Conversion Area	FT Product Upgrading Area
Aqueous Oxygenates: • Acetaldehyde • Formaldehyde • Methyl Ethyl Ketone		FT Synthesis - All Cases • Fe Catalyst • Trace from Cobalt Catalyst	
Aromatics: • Benzene • Toluene • Xylenes • Ethyl Benzene		• ZSM-5 Conversion - Option 2	• Cat Reforming - Options 1, 3-6 • Cat Cracking - Option 3
Sulfur Compounds: • Carbon Disulfide • Carbonyl sulfide	Coal - Options 1-4 • Gasification		
Acids: • Hydrochloric Acid	Coal - Options 1-4 Biomass - Option 5 • Gasification		
Olefins: • Ethylene • Propylene		FT Synthesis - All Cases • Fe Catalyst • Trace from Cobalt Catalyst	• Cat Cracking - Option 3
Alkane Solvents: • Hexane		FT Synthesis - All Cases	
Alcohols & Ethers: • Methanol • Methyl Tert Buytl Ether	• Rectisol Unit - Option 4		• Ether Synthesis- Option 3
Trace Elements: • Antimony, Arsenic, Barium, Beryllium, Boron, Cadmium, Chromium, Cobalt, Copper, Lead, Manganese, Mercury, Molybdenum, Nickel, Selenium, Vanadium	Coal - Options 1-4		

4. RESOURCE EXTRACTION

The three feedstocks considered in this analysis have quite different properties and are produced in very different ways: mining, farming and drilling. It is the relative proportions of carbon, hydrogen and oxygen in these resources and the size of the molecular structures present that give them their unique properties. Coal and biomass are solids composed of large molecules. Coals have molar hydrogen-to-carbon ratios less than 1 (0.8 for the coals considered here) and biomass has ratios between 1 and 2 (1.5 for the maplewood chips). However, during gasification, hydrogen reacts with oxygen in these feedstocks to produce H_2O. Thus, the effective hydrogen-to-carbon ratios of coal, and in particular biomass, can be much lower. Natural gas has a much higher hydrogen-to-carbon ratio of about 4. Most liquid hydrocarbons have a ratio of about 2. It is the relative deficiency or surplus of hydrogen in a feedstock, which most affects the severity of the operations necessary to convert the feedstock to liquid fuels. In turn, this affects the overall efficiency of FT conversion and the amount of CO_2 generated in the process.

4.1 Coal

Coals are classified according to their *rank*, which is defined based on the coal's fixed carbon, volatile matter, and heating value. In addition to these properties, the ash (mineral matter), moisture, sulfur, nitrogen and oxygen contents are also important. Sulfur and nitrogen contents are indicative of SOx and NOx emissions, which result from burning coal. The four major rankings used for coals are anthracite (high fixed carbon, low volatile matter, high heating value), bituminous, subbituminous and lignite (low fixed carbon, high volatile matter, low heating value). Rank is also indicative of the age of the coal seam from which the coal was mined, with lignite being the least advanced along the path to becoming anthracite coal. Bituminous coals, such as Illinois No. 6, are found in the eastern United States. Powder River Basin coal from Wyoming is typical of western subbituminous coals. The FT plant designs discussed in Section 3 were based on these two benchmark coals. These coals were selected for the conceptual designs because they are representative of the bulk of the coal used in the U.S. and because a considerable amount of information is available on them, including results from coal preparation and gasification tests. Analyses of Illinois No. 6 and Powder River Basin coal are given in Table 8.

Table 8: Ultimate Analyses of Coal and Biomass

	Illinois #6 Coal	Wyoming Coal	Maplewood Chips
HHV (M Btu/lb)	12.25	11.65	8.08
LHV (M Btu/lb)	11.95	11.20	7.72
	Wt. %	**Wt. %**	**Wt.%**
Moisture	9.41	44.9	61.0
Ash	11.49	8.71	0.50
C	71.01	67.84	49.54
H	4.80	4.71	6.11
N	1.40	0.94	0.10
S	3.19	0.58	0.02
Cl	0.10	0.01	0.00
O (by diff.)	8.01	17.21	43.73

4.1.1 Coal Mining and Post Mining Operations

Depending on local geological conditions, a number of options are available for coal mining. Economics dictate the method used to mine any given site, with the depth of the coal seam being a major factor. When a coal seam is near to, or breaks, the surface (i.e. *outcrops*), surface mining techniques are employed, such as *strip mining*. Western coals, such as Powder River Basin coal are primarily mined this way. Roughly 60% of the coal mined in the U.S. is surface-mined. When the coal seam lies sufficiently deep, underground mining techniques are employed. The two most common underground methods used in the U.S. are *room-and-pillar* and *longwall* mining. Longwall mining is the newer method and typically has economic, as well as other, advantages over traditional room-and-pillar mining. Eastern coals, such as Illinois No. 6, are often found in deeper seams, where both underground mining techniques are used. However, eastern coals are also surface-mined where possible. Other less common techniques are also still in use.

Underground mining involves excavating a number of shafts from the surface to the coal seam. These shafts may be vertical, horizontal or at some other angle depending on the topography of the mine site. Room-and-pillar and longwall mining differ by the methods and machinery used to remove the coal from the seam. In room-and-pillar mining, the coal is removed from two sets of corridors that advance through the mine at right angles to each other. The remaining, evenly spaced pillars of coal are left in place to support the overlying layers of rock. As much as half the coal in the seam is left in place for support. Even so, over long periods of time (decades to centuries), the mine will collapse, possibly causing surface subsidence. The machine used to remove coal in room-and-pillar mining is called a continuous miner. Mining using a continuous miner involves a series of operations: drilling, blasting, cutting, loading and hauling.

In longwall mining, three main corridors are first mined (using continuous miners) to form a large U-shaped passageway. The distance between the two parallel corridors is on the order of 100 to 200 meters. The "longwall" in the corridor perpendicular to these two corridors is mined continuously, using a longwall-mining machine. This machine, which has a movable roof support, advances as it removes coal from the *coalface*. Behind it, the unsupported mine roof quickly collapses, resulting in controlled surface subsidence. The coal is transported by means of conveyors to either end of the longwall where it is hauled out of the mine. With longwall mining, no coal is left in the mined portion of the seam. Many of the other operations required in underground mining are similar for both room-and-pillar and longwall mining. They include providing rock dusting, water supply, ventilation, drainage, power supply, communications and lighting.

Because longwall mining is the most efficient and lowest cost option for underground mining and is gradually replacing the older room-and-pillar method, *only longwall mining has been considered as part of this emissions inventory*. Machinery for longwall mining operations includes the longwall unit, auxiliary continuous miners, shuttle cars, roof bolters, triple rock and trickle dusters, supply cars, conveyors, tracks, front-end loaders, bulldozers and other miscellaneous equipment and vehicles. Table 9 lists the resources consumed in longwall mining. Almost all equipment operated in underground coal mining is powered by electricity in order to maintain safe air quality within the mine. Limestone is used for rock dusting to reduce the risk of coal dust explosions, and water is used to cool and lubricate coal-cutting equipment.

Surface mining involves removing the overlying soil and rock, known as *overburden*, to expose the coal seam, removing and loading the coal for transportation, and replacement of the original soil and rock (land reclamation). Blasting and/or mechanical means are used to fracture the coal seam and any overlying layers of rock. Machinery required for surface mining operations includes stripping shovels, drills, bulldozers, coal shovels, coal haulers (trucks), front-end loaders with shovels, wheel tractor scrapers, road graders, forklifts, cranes, and other miscellaneous vehicles. Table 9 lists the resources consumed in surface mining. Since much of the equipment used in surface mining is mobile, distillate fuel is a significant source of power. This fuel can be assumed to be equivalent to high-sulfur, No.2 Diesel. Ammonium nitrate is the explosive most widely used in blasting.

Post-mining operations include coal preparation and storage before final shipment by train, truck or barge. Coal preparation involves size reduction of the mined coal to facilitate the separation of rock and mineral matter, known as ash, from the raw coal. This density-based separation is referred to as jig washing or cleaning. Other more advanced coal cleaning operations, such as heavy media separation and agglomeration, have been developed, but are not commonly used in the U.S. In addition to the cleaned coal, jigging produces a refuse stream of rock, mineral matter and very fine coal particles, which can be returned to the mine for use in land reclamation. Jigging also involves the use of large quantities of water, which can be recycled, but must be treated if discharged. Table 9 lists the resources consumed and refuse generated in a typical coal preparation operation.

Table 9: Resource Consumption for Coal Production*

(Per ton of MF Coal Produced)

	Illinois #6 Underground Mine	Illinois #6 Surface Mine	Wyoming Surface Mine
Electricity (kWh)	15.4	17.2	17.4
Distillate Fuel (gal)		0.840	0.085
Water Make-Up (gal)	62.6	46.1	44.7
Limestone (lb)	42.6		
Ammonium Nitrate (lb)		5.4	5.5
Refuse (ton)	-0.310	-0.310	-0.320

*Positive value is consumed, negative is produced; values based on [16,17].

Emissions associated with the production and delivery of limestone, ammonium nitrate, etc. to the coal mine have been ignored for the LCI. The amounts of these materials used are small relative to the coal produced (0.3-2.3 wt%).

4.1.2 Coalbed Methane

Methane (CH_4) is often found in association with coal seams, either absorbed in the seam or in pockets in adjacent rock strata. Methane, if it is not removed, is a significant mining safety hazard. The amount of methane that can be absorbed in coal is a function of coal rank. Higher rank coals tend to hold more methane than lower rank coals. This methane is released when the pressure within the coalbed is reduced, either through mining activity, or through natural erosion or faulting. Due to the latter, surface mined coals frequently do not have large quantities of methane associated with them.

Methane, if found in association with coal, may be released prior to mining using de-gasification wells. This methane can be used at the mine site to satisfy electricity needs or sold as pipeline-quality natural gas. It is frequently not recovered; however, and is vented or flared. This situation is beginning to change in the U.S. with more coalbed methane being recovered and utilized. In underground mines, ventilation systems are utilized to circulate air through the mine and maintain methane levels below explosion limits. Longwall mining can release large quantities of methane, since the associated subsidence releases gas from overlying rock strata. Methane remaining in the coal after it is brought to the surface is released during post-mining operations.

The methane emission factors used in this study for underground and surface mining of eastern and surface mining of western coal are listed in Table 10.

Table 10: Coalbed Methane Emissions*
(Per ton of MF Coal Produced)

	Illinois #6	Illinois #6	Wyoming

	Underground Mine	Surface Mine	Surface Mine
CH_4 (scf)	145	90	7.4
CH_4 (g)	2779	1725	142

*Based on [18].

4.1.3 Emissions Inventory for Coal Production

Table 11 contains the LCI for the coal production step in the FT fuel chain for the options: Illinois No. 6 coal - underground longwall mine, Illinois No. 6 - surface strip mine, and Powder River Basin coal - surface strip mine. Emissions sources included in the inventory are coalbed methane releases, ancillary electricity production, and ancillary diesel fuel production and use. The emissions factors used to estimate these emissions and sample calculations are given in Appendix A. Ancillary emissions are presented in Section 6. Table 12 contains the corresponding greenhouse gas emissions in CO_2 equivalency units.

Table 11: Emissions Inventory for Coal Production
(Per ton of MF Coal Produced)

	Illinois #6 Underground Mine	Illinois #6 Surface Mine	Wyoming Surface Mine
CO_2 (g)	10904	12272	12358
CH_4 (g)	2806	1754	172
N_2O (g)	0.65	0.73	0.73
SOx (g)	106.2	119.4	120.2
NOx (g)	27.6	31.3	31.6
CO (g)	3.2	3.67	3.7
VOC (g)	27.8	31.2	31.4
PM (g)	29.3	32.9	33.2

Table 12: Greenhouse Gas Emissions from Coal Production
(Per ton of MF Coal Produced)

	Illinois #6 Underground Mine	Illinois #6 Surface Mine	Wyoming Surface Mine
CO_2 (g)	10904	12272	12358
CH_4 (g CO_2-eq)	58928	36850	3618
N_2O (g CO_2-eq)	200	225	227
Total (g CO_2-eq)	70032	49348	16203

From Table 12, it is clear that coalbed methane emissions are a significant contributor to GHG emissions from coal mining. They are the dominant GHG emission for the Illinois underground and surface mining options. Only for the Wyoming surface mining option are coalbed methane emissions significantly smaller than emissions from mining operations.

The Illinois No. 6 underground mining and the Wyoming surface mining options are used as the basis for Scenarios 1 and 2, that are presented in Section 7.

4.2 Biomass

Biomass is a broad term used to refer to any material that is or was derived from plants and animals that were recently alive; this includes agricultural and animal products, forest and yard litter, wood waste from pulp mills, portions of landfill material, municipal solid waste, etc. These materials are renewable. They can be replaced by regrowth. However, this *regrowth must be accomplished in a sustainable way for the use of biomass to have a long-term benefit*.

The composition of biomass is highly variable. An examination of all possible sources for this feedstock is beyond the scope of this study. The only biomass feedstock considered in this study is maplewood, produced on a plantation as an energy crop specifically for use in the production of fuels and power. An analysis of this feedstock is given in Table 8.

4.2.1 Biomass Plantation Operations

The plantation is assumed to surround the biomass liquefaction plant, which has been sited in southern Illinois to be consistent with the eastern coal option. Best agricultural practices are assumed and there is a planned rotation of field plantings throughout the lifetime of the plantation. Fertilizer and herbicide use has been minimized. The average distance for the short-haul from the field to the plant is 17.25 mi. (27.6 km).

Energy is consumed and emissions released for each operation required to plant, grow and harvest the biomass. The equipment required per growing cycle includes plows, sprayers, spreaders, cultivators, tree fellers, bunchers, and chippers. Trucks are used to transport the chipped wood to the liquefaction plant. The major source of energy to operate this equipment is diesel fuel.

4.2.2 Emissions Inventory for Biomass Production

Table 13 contains the LCI for the biomass production step in the FT fuel chain. It is based on the LCA conducted by NREL for biomass-gasification combined-cycle power generation [19]. The biomass feedstock used in the NREL study was hybrid poplar. It has been assumed here that the emissions factors for maplewood cultivation and harvesting are the same as for hybrid-poplar wood. Because trees absorb CO_2 when they grow, the production of biomass results in a net removal of CO_2 from the atmosphere (the negative emission of CO_2 in Table 13). The effects of agriculture on soil and its ability to hold or absorb carbon are controversial, and it was assumed in the NREL study that agricultural best practices would not result in any net loss or gain of carbon in the soil. There is also great uncertainty as to emissions of CH_4 and N_2O during agriculture. NREL's study assumes only modest emissions of these gases from the soil.

Emission sources for biomass production were discussed in the previous section. The values given in Table 13 are aggregated for all sources associated with cultivation and harvesting, including ancillary feedstocks and short-haul transportation of the biomass from the fields to the FT conversion facility by diesel truck. Table 14 contains the corresponding greenhouse gas emissions in CO_2 equivalency units.

Table 13: Emissions Inventory for Biomass Production*
(Per ton of MF Biomass Produced)

	Feedstock Sequestering	Cultivation & Harvesting	Local Transportation	Total
CO_2 (g)	-1648273	52333	10162	-1585778
CH_4 (g)		8.3	0.39	8.7
N_2O (g)		16.9	0.40	17.3
SOx (g)		na	na	Na
NOx (g)		307	49.4	356.4
CO (g)		124	19.9	144
VOC (g)		129.3	14.7	144
PM (g)		na	na	Na

*Based on [19].

Table 14: Greenhouse Gas Emissions from Biomass Production
(Per ton of MF Biomass Produced)

	Feedstock Sequestering	Cultivation & Harvesting	Local Transportation	Total
CO_2 (g CO_2)	-1648273	52333	10162	-1585778
CH_4 (g CO_2-eq)		175	8.2	183
N_2O (g CO_2-eq)		5239	124	5363
Total (g CO_2-eq)	-1648273	57747	10294	-1580232

Plantation biomass is the basis for Scenario 3 of the full emissions inventory presented in Section 7.

4.3 Natural Gas

Natural gas occurs either separately from, or in association with, petroleum or coal. Methane (CH_4) is the major constituent, but other hydrocarbons such as ethane (C_2H_6), propane (C_3H_8), butanes (C_4H_{10}), and heavier (C5+) may also be present, especially when the gas is found in association with oil. The FT plant designs discussed in Section 3 considered two gas compositions. These are given in Table 15. The associated gas composition is typical of the gas produced along with Alaska North Slope oil. It contains 13% CO_2, negligible H_2S, and has been processed to remove and recover C5+ hydrocarbons. The composition of associated gas can vary considerably from location to location. The second composition given in Table 15 is for pipeline quality gas.

Table 15: Composition of Associated & Pipeline Natural Gas*

	Associated Gas	Pipeline Gas
HHV (Btu/scf)	925.3	1002.5
LHV (Btu/scf)	835.4	904.6
	Vol. %	**Vol. %**
Methane	76.2	94.7
Ethane	6.4	3.2
Propane	3.2	0.5
Isobutane	0.3	0.1
n-Butane	0.8	0.1
C_5+	0.1	0.1
CO_2	12.6	0.7
H_2S	-	-
N_2	0.4	0.6

*Based on [9,13].

4.3.1 Oil & Gas Production Operations

Natural gas is produced from natural gas production wells or as associated gas from oil production wells. Natural gas is also produced from coalbed methane recovery wells, which have not been considered here. In either case, a field separation unit is used to separate produced gas, liquid hydrocarbons and liquid water. In a true gas field, the amount of liquid hydrocarbons produced is very small, and the liquid hydrocarbon mixture is referred to as *field condensate*. Gas from the field separators is gathered by a field pipeline network and fed to a gas processing plant. The purpose of the gas processing plant is to remove impurities in the gas, such as CO_2 and H_2S, and to recovery C3+ hydrocarbons. Removal of CO_2 and H_2S is referred to *gas sweetening*, and recovery of hydrocarbon liquids is referred to *gas conditioning*. Gas leaving the gas plant is of pipeline quality and is transported long distances to markets remote from the field in high-pressure natural gas transmission pipelines or liquefied cryogenically and shipped in LNG (liquefied natural gas) tankers. In oil fields, the gas may be re-injected into the reservoir to maintain pressure and enhance oil recovery. Ethane recovered from the gas may be sold as a petrochemical feedstock for producing ethylene or used as gas plant fuel. Propane, butanes and higher hydrocarbons recovered at the gas plant are referred to as natural gas liquids (NGLs). All are used as petrochemical feedstocks. Propane is also sold as LPG (liquefied petroleum gas) which is used as a fuel. Butanes are blended or converted into gasoline components, and C5+ liquids, referred to as *natural gasoline*, are also blended into gasoline.

4.3.2 Emissions Inventory for Natural Gas Production

Table 16 contains the LCI for the natural gas production step in the FT fuel chain. Emissions sources included in the inventory are natural gas venting and flaring, gas plant fuel combustion, and fugitive emissions. For pipeline natural gas, emissions for transportation and distribution are also included. It has been assumed that natural gas is the sole source of process fuel and power at the production site. Emissions of SOx for associated gas is negligible, since the composition of gas used (see Table 15) contains no sulfur compounds. This is not typical, as can be seen from the SOx value reported in Table 16 for the pipeline gas option. Table 17 contains the corresponding greenhouse gas emissions in CO_2 equivalency units.

Table 16: Emissions Inventory for Natural Gas Production*
(Per Mscf of Natural Gas Produced)

	Associated Gas	**Pipeline Gas**
CO_2 (g)	4427	6364
CH_4 (g)	22.8	69
N_2O (g)	0.15	0.21
SOx (g)	na	0.21
NOx (g)	33.7	48.4
CO (g)	8.2	11.8
VOC (g)	53.6	77
PM (g)	0	0

*Based on [20,21].

Table 17: Greenhouse Gas Emissions from Natural Gas Production
(Per Mscf of Natural Gas Produced)

	Associated Gas	**Pipeline Gas**
CO_2 (g CO_2)	4427	6364
CH_4 (g CO_2-eq)	478.8	1449
N_2O (g CO_2-eq)	45.3	65
Total (g CO_2-eq)	4951	7878

The difference in the emissions for pipeline versus associated gas is attributed to gas transportation and distribution. Pipeline gas is used as the basis for Scenario 4, and associated gas as the basis for Scenarios 5 and 6 in the full emissions inventory presented in Section 7.

5. TRANSPORTATION & DISTRIBUTION

The various scenarios considered for this inventory involve moving feedstocks and products over long distances. The means of transportation depends on the starting and ending point. All scenarios involve multiple transportation steps. To standardize comparisons, all the scenarios excluding Scenario 6, assume the end-use of the FT fuel occurs in the vicinity of Chicago, IL.

5.1 Transportation Modes & Distances

Scenarios 1 (Illinois No. 6 coal), 3 (biomass), and 4 (pipeline gas) all use southern Illinois as the location of the FT plant. The U.S. Midwest is a reasonable location for the future siting of coal liquefaction plants, as well as, biomass conversion plants. The high cost of pipeline gas makes Scenario 4 unlikely; however, it has been included to allow comparisons to be made between the different feedstocks on a consistent basis. The ultimate source of the pipeline natural gas has not been identified; however, a generic gas pipeline transmission step has been lumped into the emissions factor reported for pipeline natural gas production (see Tables 16 and 17, previous section).

The FT fuels produced in southern Illinois are shipped by pipeline to the Chicago area and distributed to local refueling station by tank truck. Scenario 2 assumes a Wyoming location for the FT plant, again with products shipped by pipeline to the Chicago area for distribution. Scenario 5 is based on the conversion of stranded, associated gas in Venezuela. Transportation of the FT fuels produced in Venezuela is by tanker to the U.S. Gulf Coast, followed by pipeline transmission to the Chicago area. While a small quantity of Alaska North Slope (ANS) crude finds its way to the Midwest every year, it is unlikely that substantial quantities of ANS crude or GTL would be refined and marketed there due to cost and logistic issues. Scenario 6 is based on FT production on the North Slope of Alaska (to monetize stranded gas reserves). The FT fuels produced are transported via the Trans-Alaska pipeline to Valdez, transferred to a tanker, and transported to the U.S. West Coast, where they are refined/blended into fuels for distribution in the San Francisco Bay area.

Energy usage for different modes of transportation is listed in Table 18. Mileage for the different transportation routes considered was estimated using standard atlases and is listed for the different scenarios in Tables 19-22.

Table 18: Energy Consumption for Different Modes of Transportation*
(Per ton-mile Transported)

Truck	Tanker	Tank Car	Pipeline
Btu	Btu	Btu	kWh
1900	408	516	0.0352

*Based on [20,21].

5.2 Emissions Inventory for Transportation & Distribution

Tables 19-22 contain the LCIs for the various transportation scenarios considered. Emissions sources included in the inventories are the combustion of the fuel used for each transportation step and upstream emissions associated with producing this fuel. Electricity is used to power pipeline pumps. Distillate fuel oil (DFO) is used for tank trucks, and residual fuel oil (RFO) for tankers. The emissions factors used to estimate these emissions and sample calculations are given in Appendix A. Ancillary emissions are presented in Section 6. Table 23 contains the corresponding greenhouse gas emissions in CO_2 equivalency units for all scenarios considered.

Table 19: Emissions Inventory for Transportation Scenarios 1, 3 & 4
(Per gal of FT Fuel Transported)

Transportation Mode		Truck	Tanker	Pipeline	Total
Southern Illinois to Chicago		DFO	RFO	Electricity	
Miles		60	0	200	260
CO_2	**(g)**	28.29	0	5.00	33.3
CH_4	**(g)**	0.0015	0	0.0124	0.0139
N_2O	**(g)**	0.0009	0	0.0003	0.0012
SOx	**(g)**	0.1389	0	0.0487	0.1876
NOx	**(g)**	0.1223	0	0.0185	0.1408
CO	**(g)**	0.1638	0	0.0059	0.1697
PM	**(g)**	0.0235	0	0.0134	0.0369
VOC	**(g)**	0.0011	0	0.00013	0.0012

Table 20: Emissions Inventory for Transportation Scenario 2
(Per gal of FT Fuel Transported)

Transportation Mode		Truck	Tanker	Pipeline	Total
Wyoming to Chicago		DFO	RFO	Electricity	
Miles		60	0	1000	1060
CO_2	**(g)**	28.29	0	25.00	53.30
CH_4	**(g)**	0.0015	0	0.0619	0.0634
N_2O	**(g)**	0.0009	0	0.0014	0.0023
SOx	**(g)**	0.1389	0	0.2434	0.3824
NOx	**(g)**	0.1223	0	0.0923	0.2147
CO	**(g)**	0.1638	0	0.0296	0.1934
PM	**(g)**	0.0235	0	0.0672	0.0907
VOC	**(g)**	0.0011	0	0.00067	0.0017

Table 21: Emissions Inventory for Transportation Scenario 5
(Per gal of FT Transported)

Transportation Mode		Truck	Tanker	Pipeline	Total
Venezuela to Chicago		DFO	RFO	Electricity	
Miles		60	2000	1200	3260
CO_2	**(g)**	28.29	218	30.00	276.23
CH_4	**(g)**	0.0015	0.2897	0.0742	0.3654
N_2O	**(g)**	0.0009	0.0050	0.0017	0.0076
SOx	**(g)**	0.1389	2.7352	0.2921	3.1663
NOx	**(g)**	0.1223	0.7158	0.1108	0.9489
CO	**(g)**	0.1638	0.1246	0.0355	0.3239
PM	**(g)**	0.0235	0.1652	0.0806	0.2693
VOC	**(g)**	0.0011	0.1077	0.00081	0.1096

Table 22: Emissions Inventory for Transportation Scenarios 6
(Per gal of FT Fuel Transported)

Transportation Mode		Truck	Tanker	Pipeline	Total
ANS to San Francisco		DFO	RFO	Electricity	
Miles		60	4130	800	4990
CO_2	**(g)**	28.29	450	20	498.32
CH_4	**(g)**	0.0015	0.5982	0.0495	0.6492
N_2O	**(g)**	0.0009	0.0104	0.0011	0.0124
SOx	**(g)**	0.1389	5.6483	0.1947	5.9819
NOx	**(g)**	0.1223	1.478	0.0739	1.674
CO	**(g)**	0.1638	0.2572	0.0236	0.4447
PM	**(g)**	0.0235	0.3411	0.0537	0.4183
VOC	**(g)**	0.0011	0.2224	0.00054	0.2240

Table 23: Greenhouse Gas Emissions from Transportation
(Per gal of FT Fuel Transported)

	Truck	Tanker	Pipeline	Total
Scenario 1, 3 & 4 (g CO_2-eq)	28.61	0	5.35	33.96
Scenario 2 (g CO_2-eq)	28.61	0	26.74	55.35
Scenario 5 (g CO_2-eq)	28.61	225.57	32.08	286.26
Scenario 6 (g CO_2-eq)	28.61	465.80	21.39	515.80

The most significant factors in determining transportation related emissions are fuel type and overall distance traveled (delivery and return trips). The combustion of RFO generates larger emissions of criteria pollutants than DFO and electricity generation and tanker routes are longer.

Fugitive emissions for intermediate product storage (marine and distribution terminals) along the various routes are expected to be insignificant relative to transportation and distribution and have been ignored for the LCI.

6. FUEL COMBUSTION, EFFICIENCIES & ANCILLARY EMISSIONS

This section contains a summary of ancillary emissions used in this LCI to estimate emissions along the FT fuel chain, and other factors required for estimating full life-cycle emission on a per vehicle mile basis.

6.1 Emissions Inventory for Ancillary Feedstocks

Emission factors for ancillary feedstocks were compiled from a number of sources [6,20,21,22]and are given in Table 24. The feedstocks of interest are electricity used in mining, FT production and pipeline transportation of FT products; low-sulfur, distillate fuel oil (DFO) used for tank truck distribution of FT products; high-sulfur, distillate fuel oil used by surface mining equipment; residual fuel oil (RFO) used in tanker transportation of FT products; fuel gas used in FT production, and butanes and methanol used to upgrade FT products. Upstream emissions are included in these factors, except for fuel gas, which is generated at the FT plant. Electricity emissions are based on a standard mix of power generation sources in the U.S. of 51% coal, 3% fuel oil, 15% natural gas, 20% nuclear, and 11% renewable sources.

Table 24: Emissions Inventory for Ancillary Feedstocks

	Electricity	Diesel Truck	Heavy Equip.	Tanker	Fuel Gas	Butane	Methanol
	Delivered	Delivered & Consumed	Delivered & Consumed	Delivered & Consumed	Consumed	Delivered	Delivered
	(g/kWh)	(g/MM Btu)	(g/MM Btu)	(g/MM Btu)	(g/MM Btu)	(g/bbl)	(g/bbl)
MM Btu/bbl	-	5.83	5.83	6.29	-	-	-
CO_2	711	80503	80503	86680	calculated	25859	11172
CH_4	1.76	4.3	4.3	15.2	1.3	92	112
N_2O	0.042	2.6	2.0	2.0	2.0	0.84	1.59
SOx	6.92	396	454	1088	0.0	8.1	102
NOx	1.8	348	937	818	63.6	149	165
CO	0.205	466	404	303	15.4	34.7	37.8
VOC	1.81	93.2	68.4	152	2.7	215	225
PM	1.91	66.9	70.53	97.50	1.36	6.7	11.1

6.2 Combustion Properties of Selected Fuels

Table 25 lists the CO_2 emissions factors for full combustion of the various products from the FT plant designs described in Section 3. These values are used to estimate the carbon emissions for end-use combustion of FT fuels. Also given in Table 25 are the emissions associated with the flaring and venting of associated gas; these are used in the sensitivity analysis presented in Section 7.3.

Table 25: CO_2 Emissions from Combustion of Selected Fuels

FT Gasoline/Naphtha	**Wt. % C**	**g CO_2/gal**
Design Option 1	85.63	8551
Design Option 2	85.05	8408
Design Option 3	78.73	7825
Design Option 4	85.63	8550
Design Option 5	86.81	8813
Design Option 6	85.95	8602
Design Options 7, 8	84.60	8058
FT Distillate		
Design Options 1, 2, 4-8	84.60	9011
Design Option 3	84.86	8956
	Wt. % C	**g CO_2/Mscf**
Flared Associated Gas	61.96	55984
	Wt. % C	**g CO_2-eq/Mscf**
Vented Associated Gas	61.96	313521

6.3 Vehicle Fuel Economies

The case study and sensitivity analysis presented in Sections 7.2 and 7.3 are for SUVs powered by conventional and advanced compression-ignition diesel engines. In order to estimate emissions for this study or others to be considered in the future, it is necessary to have an estimate of fuel economies for various vehicles and technologies. Table 26 contains fuel economies in units of miles-per-gallon (mpg) for various existing and future vehicle technologies based on efficiency estimates prepared by Argonne National Laboratory (ANL) [23]. It assumes spark-ignition engines are currently fueled by petroleum-derived gasoline and compression-ignition engines are fueled by petroleum-derived diesel fuel. The hybrid engine technologies consider on-board electricity generation and storage, and are not considered in this LCI.

Given mpg for one vehicle and technology, an estimate for the same vehicle with a different technology can be estimated from Table 26. The values in this table are based on the average energy content of petroleum-derived gasoline and diesel used in the U.S. Since FT fuels will have different energy contents than those derived from petroleum, the fuel economies in Table 26 must be adjusted based on the ratio of the heating value of the FT fuel to heating value of the petroleum fuel. For FT diesel this factor is 0.92.

Table 26: Vehicle Fuel Economy-Technology Matrix*
(miles-per-gallon)

Spark Ignition									
Conventional	10.0	15.0	20.0	25.0	30.0	35.0	40.0	45.0	50.0
Hybrid Electric	16.3	24.4	32.5	40.6	48.8	56.9	65.0	73.1	81.3
Direct Injection	12.7	19.0	25.3	31.6	38.0	44.3	50.6	57.0	63.3
Hybrid/Direct Inject	19.2	28.8	38.5	48.1	57.7	67.3	76.9	86.5	96.2
Compression Ignition									
Conventional	13.3	20.0	26.6	33.3	40.0	46.6	53.3	59.9	66.6
Advanced	15.3	23.0	30.6	38.3	46.0	53.6	61.3	68.9	76.6
Hybrid Electric	20.0	30.1	40.1	50.1	60.1	70.2	80.2	90.2	100.2
Advanced Hybrid	23.1	34.6	46.1	57.6	69.2	80.7	92.2	103.7	115.3

*For FT fuel multiply mpg by 0.92.

Comparisons between vehicles powered by gasoline spark-ignition and diesel compression-ignition engines must be done carefully. While there is a clear relationship between fuel economy and engine type, the basis for the comparison must also include the same type of vehicle used in similar applications (i.e., city or highway driving). For example, the average fuel economy for gasoline-powered passenger cars in the U.S. is about 30.7 mpg, for gasoline-powered SUVs it is 20 mpg, and for light-duty diesel-powered vehicles it is about 39 mpg. In similar applications, diesel engines are 33% more efficient than gasoline engines (from Table 26, (13.3 - 10.0 mpg)/10.0 mpg = 0.33). Therefore, converting all SUVs powered by gasoline to diesel would result in a fuel economy increase from 20 to 26.6 mpg (not to 39 mpg). Fuel composition also plays an important role in fuel economy. Substituting FT diesel for petroleum diesel in today's diesel-powered vehicles would result in a decrease in fuel economy from about 39 to 35.8 mpg, an 8% decrease. This is a result of the inherent lower energy density per gallon of FT diesel relative to conventional petroleum diesel.

7. FULL FT-FUEL LIFE-CYCLE INVENTORY

Six baseline scenarios were identified for consideration in this study. They involve the evaluation of different options for the resource extraction, conversion, and transportation/distribution steps in the FT fuel chain. Descriptions of these scenarios are given below.

<u>Scenario 1</u>

Production of FT fuels from bituminous Illinois No. 6 coal at a mine-mouth location in southern Illinois. The mine is an underground longwall mine. The design of the FT conversion plant is based on Option 1 described in Section 3. Upgrading includes a full slate of refinery processes for upgrading FT naphtha. Hydrocracking is used to convert the FT wax into additional naphtha and distillate. The liquid fuel products are shipped by pipeline to a terminal in the Chicago area and distributed by tank truck to refueling stations in the immediate area.

<u>Scenario 2</u>

Production of FT fuels from subbituminous Powder River Basin coal at a mine-mouth location in Wyoming. The mine is a surface strip mine. The design of the FT conversion plant is based on Option 4 described in Section 3. Upgrading steps are identical to those used in Scenario 1. The liquid fuel products are shipped by pipeline to a terminal in the Chicago area and distributed by tank truck to service stations in the immediate area.

<u>Scenario 3</u>

Production of FT fuels from plantation biomass (maplewood chips) at a location in southern Illinois. The design of the FT conversion plant is based on Option 5 described in Section 3 and co-produces electric power. Some naphtha upgrading is included; however, no LPG product is produced. Hydrocracking is used for FT wax conversion. The liquid fuel products are shipped by pipeline to a terminal in the Chicago area and distributed by tank truck to service stations in the immediate area.

<u>Scenario 4</u>

Production of FT fuels from pipeline natural gas at a location in southern Illinois. The design of the FT conversion plant is based on Option 6 described in Section 3. Upgrading steps are identical to those used in Scenarios 1. The liquid fuel products are shipped by pipeline to a terminal in the Chicago area and distributed by tank truck to service stations in the immediate area.

<u>Scenario 5</u>

Production of FT fuels from associated natural gas (of same composition as ANS gas) at a wellhead location near the coast of Venezuela. The design of the FT conversion plant is based on Option 7 described in Section 3. FT wax hydrocracking is included; however, no upgrading of the naphtha is performed. The liquid fuel products are shipped by tanker to a U.S. Gulf Coast marine terminal. From there they are shipped by pipeline to a terminal in the Chicago area and distributed by tank truck to service stations in the immediate area.

Scenario 6

Production of FT fuels from associated natural gas at a wellhead location on the Alaska North Slope. The design of the FT conversion plant is based on Option 7 described in Section 3 and is identical to that used for Scenario 5. The liquid fuel products are shipped by the Trans-Alaskan Pipeline to Valdez on the southern coast of Alaska. There they are transferred to a tanker for shipment to a marine terminal in the San Francisco Bay area and distributed by tank truck to service stations in the immediate area.

7.1 Emissions Inventory for Full FT Fuel Chain

Table 27 contains the LCI for the six scenarios described in the preceding section. This was compiled from the individual inventories for the resource extraction, conversion, and transportation/distribution steps of the FT fuel chain described in Sections 3, 4 and 5 of this report. *They are the full inventories up through the point of sale of the FT fuel* and are based on the entire FT liquid-fuel product slate. That is, the individual products (LPG, gasoline/naphtha, and distillate fuel) have not been broken out separately. Refueling and end-use combustion are not included. Refueling emissions are related to the volatility of the fuel. Because FT distillate is composed primarily of high-boiling paraffins, the volatility of diesel fuel is very low, and refueling emissions can be neglected in the LCI. The volatility of FT naphtha or gasoline derived from this naphtha will depend on the upgrading of this stream, and fugitive emissions for this product are not considered further in this analysis. The inclusion of end-use combustion emissions, other than CO_2, in the inventory requires specification of the end-use combustion device and its efficiency. Section 7.2 considers GHG emissions for the specific application of FT diesel in diesel-powered SUVs. In general, the emissions from FT diesel combustion are low; however, further work will be necessary to characterize the CP emission reduction benefits of FT fuels for specific vehicle applications.

Table 27: Emissions Inventory for FT Fuels at Point of Sale
(Per gal of FT Fuel Supplied)

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
CO_2 (g)	12850	13865	-6564	4236	6385	6607
CH_4 (g)	26.0	3.76	0.45	14.9	6.07	6.36
N_2O (g)	0.0582	0.08	0.65	0.08	0.09	0.096
SOx (g)	5.82	8.61	0.19	0.23	3.22	6.03
NOx (g)	2.50	3.34	17.8	11.7	10.4	10.8
CO (g)	0.57	0.68	5.33	2.98	2.46	2.49
VOC (g)	1.71	2.47	2.66	16.5	13.2	13.2
PM (g)	1.49	2.35	0.30	0.06	0.30	0.45

Emissions reported in Table 27 follow the trends observed in Table 4 for the FT production step. Most emissions are higher for the coal and biomass designs relative to the gas-to-liquid designs. FT production is the dominant source of all emissions upstream of end use combustion. The major exception is CH_4 emissions from underground mining of Illinois No. 6 coal, which is the largest single source of CH_4 emissions in Scenario 1.

7.2 Case Study - Substitution of FT Diesel Fuel in SUVs

The results from the FT LCI were used to evaluate the substitution of FT diesel for petroleum-derived fuels in Sport Utility Vehicles (SUVs) and the effect this substitution would have on greenhouse gas emissions. SUVs are almost exclusively powered by conventional spark-ignition internal combustion engines and fueled with petroleum-derived gasoline. In the U.S. they average roughly 20 mpg. Mileage for SUVs could be significantly improved by the use of diesel compression-ignition engines, which are about 33% more efficient than gasoline spark-ignition engines. Their use would result in an improvement in fuel economy to about 26.6 mpg. However, conventional diesel engines are high emitters of criteria pollutants. It has been demonstrated that FT diesel produces emissions that are much lower than those from petroleum-derived diesel. There is, however, a penalty to fuel economy when using FT diesel due to its lower energy density per gallon relative to petroleum-derived diesel. FT diesel fuel economy in an SUV has been estimated to be about 24.4 mpg. The full fuel-chain GHG emissions inventory for Scenarios 1-6 is presented in Table 28.

Table 28: Full Life-Cycle GHG Emissions for FT Diesel
(g CO_2-eq/mile in SUV)

Scenario/ FT Plant Feedstock	Extraction/ Production	Conversion/ Refining	Transport./ Distribution	End Use Combustion	Total Fuel Chain
1) IL #6 Coal	26	543	1	368	939
2) Wyoming Coal	7	585	2	368	962
3) Plantation Biomass*	-969	703	1	368	104
4) Pipeline Natural Gas	71	121	1	368	562
5) Venezuelan Assoc. Gas	51	212	12	368	643
6) ANS Associated Gas	51	212	21	368	652

*-969 = -1011 absorbed by biomass + 42 emitted during production.

The end-use combustion emissions (368 g CO_2-eq/mile) have been assumed constant for all the scenarios. Minor differences in the diesel produced by the various FT plant designs have been ignored (only Option 3 produces a distillate with a significantly different carbon and energy content, and this design has not been selected for consideration in any of these scenarios). The scenarios analyzed all employed FT wax hydrocracking and, unlike petroleum-derived diesel, FT diesel is of consistent high quality, regardless of the feedstock used for its production.

The results presented in Table 28 illustrate a number of interesting points. Emissions from transportation (1 to 21 g CO_2-eq/mile) clearly correlate to the distance the FT fuel is moved to market. Transportation emissions are low (1 to 2 g/mile) for domestic coal and biomass based scenarios, due to the close vicinity of the coal field or plantation and the FT plant to the fuel market (Chicago). For the coal and biomass Scenarios 1, 2 and 3, the largest single source of emissions is the indirect liquefaction facility (543 to 703 g/mile), with GHG emissions even larger than those for end-use combustion. For pipeline natural gas, GTL conversion emissions (121 g/mile) are lower than those for end-use combustion. Carbon and oxygen must be removed from coal and biomass to convert them into a liquid. This step requires energy and consumes syngas. The GTL process extracts hydrogen from methane to produce liquid fuels. However, there is still a significant emissions penalty with GTL, due to the consumption of energy during conversion, with subsequent emissions of CO_2. If the produced natural gas contains significant quantities of CO_2, emissions of GHG from conversion can be dramatically higher, as can be seen by comparing Scenario 5 or 6 to Scenario 4 (212 vs. 121 g/mile, respectively).

While biomass conversion emissions are higher than those for coal (703 vs. 543-585 g CO_2-eq/mile); overall, the full-fuel chain GHG emissions for biomass-based FT fuels is very low (104 g/mile). Biomass is a renewable resource, and the carbon it contains is recycled between the atmosphere and the fuel (resulting in the fixation of 1011 g of atmospheric CO_2/mile in the biomass). However, biomass cultivation and harvesting result in GHG emissions (42 g/mile), and biofuels should not be considered CO_2 emissions free.

Table 29 contains the GHG emissions per kWh for electric power produced and sold by the FT plants in Scenarios 3, 4 and 6d (6d is described in section 7.3). Also given for comparison are life-cycle GHG emissions for the average electricity generated in the U.S. (based on the results in Table 24) for typical existing, new and advanced PC (Pulverized-Coal) power plants using Illinois No. 6 coal [16] and for a biomass-gasification combined-cycle power plant based on the BCL design [19]. The allocation procedure used for fuels and power affects the relative values reported in Tables 28 and 29 for these scenarios. It is clear that for all the co-production scenarios, the GHG emissions for power generation are substantially lower than the norm for operating power generation plants in the U.S. The efficiencies reported in Table 29 for power production are total plant electrical efficiencies, whereas, those reported for the different scenarios only consider the actual power-producing device (gas or steam turbine) within the FT plant.

Table 29: Full Life-Cycle GHG Emissions for Power Exported from FT Plants
(g CO_2-eq/kWh of Electric Power)

Scenario/ FT Plant Feedstock	All Upstream	Electricity Generation	Total Fuel Chain	Electric Efficiency
3) Plantation Biomass	-1138	828	-309	60%
4) Pipeline Natural Gas	142	244	386	35%
6d) ANS Associated Gas	59	109	168	60%
U.S. Average All Plants	77	682	759	-
U.S. Average PC Plants	51	995	1045	32%
NSPS PC Plant	46	917	963	35%
LEBS PC Plant	21	722	743	42%
Biomass Gasification Combined-Cycle	-853	890	37	37%

The negative value (-309 g CO_2-eq/kWh) reported in Table 29 for Scenario 3 implies that the allocation procedure used skews the benefits of renewable biomass toward power generation relative to FT fuels production. This is also true for the natural gas-based designs that co-produce power.

7.3 Sensitivity Analysis

To help identify possible GHG reduction strategies for FT fuels production, a number of sensitivity cases were considered for the baseline scenarios described above. These included the application of advanced diesel engine technologies; coalbed methane capture, sequestration of process CO_2 from FT production; sequestration of process and combustion CO_2 from FT production; co-production of fuels and power; co-processing of coal and biomass; co-processing of coal and coalbed methane; and capture and conversion of flared or vented associated natural gas. Sequestration involves the collection, concentration, transportation and storage of CO_2 to reduce GHG emissions. Co-production refers to the production of multiple products from the indirect liquefaction plant; in this case, both fuels and power. Co-processing refers to the production of FT fuels from multiple feedstocks; for example, coal with biomass. Results are given in Table 30.

Table 30: Life-Cycle Sensitivity Analysis for FT Diesel
(g CO_2-eq/mile in SUV)

Scenario/ Modification to Baselines	GHG Emissions Reduction		Total Fuel Chain existing diesel engine	Total Fuel Chain advanced diesel engine
1a) IL #6 coal baseline	-	-	939	816
1b) with seq. of process CO_2	449	48%	490	426
1c) with seq. of process & comb. CO_2	516	55%	423	368
1d) with co-prod. of fuels & power	304	32%	635	552
1e) with co-proc. of biomass	155	17%	783	682
1f) with coalbed CH_4 capture	22	2.3%	917	798
1g) with co-proc. of coalbed CH_4	234	25%	705	613
4a) Pipeline natural gas baseline	-	-	562	489
4b) with seq. of process CO_2	65	12%	497	432
4c) with seq. of process & comb. CO_2	120	22%	442	384
5a) Venezuelan assoc. gas baseline	-	-	643	559
5b) with flaring credit	578	90%	65	57
5c) with venting credit	3234	503%	-2592	-2255
6a) ANS associated gas baseline	-	-	652	567
6b) with seq. of process CO_2	94	14%	558	485
6c) with seq. of process & comb. CO_2	211	32%	441	383
6d) with co-prod. of fuels & power	119	18%	534	464

The GHG emission reductions reported in Table 30 were estimated from the detailed energy and material balances reported for the conceptual process designs. However, they are only possible maximums since they do not include any analysis (re-design) of the conceptual FT process they were based on. They assume 100% recovery of CO_2 and CH_4 by the processes that might be used for the capture of these gases and ignore any possible energy penalties due to these processes.

For the production of FT fuels from fossil feedstocks, carbon (CO_2) sequestration would have the greatest impact on GHG emissions reductions. The sensitivity analysis presented in Table 30 shows that it might be possible to reduce GHG emissions from coal liquefaction by 48% (939 to 490 g CO_2-eq/mile for Scenario 1) and from GTL by 12-14% (562 to 497 and 652 to 558 g/mile for Scenarios 4 and 6, respectively), by sequestering the high-purity CO_2 stream being produced from the FT conversion plant. In addition, a significant quantity of CO_2 is generated from FT plant fuel combustion. If oxygen were used for combustion, this CO_2 could also be captured as a concentrated stream and sequestered, resulting in 55%, 22% and 32% reductions in total fuel-chain GHG emissions for Scenarios 1, 4 and 6, respectively. Both of these options would likely result in significant parasitic energy and cost penalties for the FT conversion process. However, these might be minimized by the application of new and developing technologies. Using pure CO_2 as a diluent could mitigate materials problems resulting from oxygen-rich combustion in fired heaters, boilers and gas turbines, and advanced oxygen production technologies could have significant benefits.

Sequestration shows less benefit for natural gas than for coal conversion. This results from less CO_2 being generated in the syngas generation and FT conversion steps for GTL. The larger total reduction for Scenario 6c relative to 4c (32 vs. 22%) is a result of the capture and sequestration of the 13% CO_2 present in the associated gas feedstock. The GHG emissions from coal or natural gas conversion are almost the same (423 vs. 441 g CO_2-eq/mile for Scenarios 1c and 4c/6c, respectively), if vented CO_2 and CO_2 from combustion are sequestered. The only remaining GHG emissions from FT production are fugitive and ancillary emissions, which are small and may also be reduced. The emissions from the natural gas scenarios with sequestration are even slightly larger than those from the coal scenario with sequestration. This is due to the higher production/extraction and transportation/distribution emissions for the natural gas scenarios considered here.

Scenario 6d considers the co-production of FT fuels and power. This estimate is based on FT plant design Option 8. Design Options 7 and 8 are identical except that Option 7 is self-sufficient in power and produces no excess electrical power for sale; whereas, Option 8 generates excess power from unconverted syngas and other plant fuel gas streams. This “once-through” conversion approach results in a 56% reduction in emissions from FT production, and an 18% reduction in total GHG emissions (from 652 to 534 g CO_2-eq/mile) based on the allocation procedure employed for this study. These gains are achieved by eliminating the recycle and reforming of off-gas produced in the FT conversion process. Assuming an equivalent percentage reduction in the FT conversion step of Scenario 1 results in a 32% reduction in full fuel-chain GHG emissions for indirect coal liquefaction (from 939 to 635 g/mile). *A detailed analysis is required to determine if this large of a reduction could actually be possible for a coal-based co-production facility*.

Co-processing of other feedstocks with coal may also be a viable approach to reducing GHG emissions. Scenarios 1e and 1g indicate that emissions could be cut roughly 17 to 25% from the coal conversion scenario (from 939 to 705-783 g CO_2-eq/mile) by co-feeding 20% biomass to gasification or by producing half the fuel product from methane rather than coal. Both these situations have other merits. The quantity of biomass available from a single plantation is quite small relative to the coal available from a single mine. At present, substitution of renewable biomass is hampered by the diffuse nature of this resource and is limited to at most 20% (LHV-basis) of the feed to a typical FT plant (50,000 bpd). Integrating the conversion of coal and biomass in a single co-processing facility would improve the economics of biomass conversion through shared economies of scale.

As discussed in Section 4, substantial quantities of methane are found associated with coal seams. Capture of coalbed methane from the mined seam only provides a small reduction in GHG emissions (2.3% based on Scenario 1f). If this methane were converted to FT fuels, it would only increase production by about 300 bpd for a 50,000 bpd plant. However, in certain coal producing regions, large quantities of coalbed methane could be produced from unmineable seams. Production of CH_4 from these seams can be stimulated by injecting CO_2 into the seam. Thus, this option provides an opportunity to sequester CO_2 produced from the FT process.

Scenarios 5b and 5c show the effect of reducing gas flaring and venting. In some parts of the world, significant amounts of associated gas are flared, because there is no readily available market for this natural gas. In Scenario 5b, it is assumed that the gas being used to produce the FT fuels was previously being flared. When credit is taken for eliminating flaring, full fuel-chain emissions are cut drastically (from 643 to 65 g CO_2-eq/mile). The situation is even more dramatic if this gas was simply being vented (from 643 to –2592 g/mile), since methane is such a potent greenhouse gas. Venting of associated gas was not uncommon only a few decades ago. The elimination of flaring and venting could under future regulations result in "carbon-credits" which could be sold in any market-based approach to reducing GHG emissions worldwide.

The last column in Table 30 lists the corresponding GHG emissions for SUVs powered by advanced diesel engines achieving 28.1 mpg, when operated on FT diesel. The net result of this next-generation vehicle technology is an across the board 13% reduction in emissions per mile. In general, CP emissions from FT diesel combustion are lower than those from petroleum-derived diesel, making FT diesel an ideal alternative to petroleum-derived diesel in advanced engines.

7.4 Comparison of FT and Petroleum-Derived Diesel Fuels

It is interesting to compare the results from the LCI for FT diesel to those for petroleum-derived diesel. Literature data were used to make this comparison. The petroleum-derived diesel estimates listed in Table 31 are based on information given in an article published by T.J. McCann & Associate Ltd. [24]. While these results cannot be independently verified, they have been reported to be from detailed private-client studies. As such, they can be assumed to include sources of data on emissions that are difficult or impossible to estimate without the involvement of petroleum producers, transporters and refiners. Based on crude oil properties and location, this information was used to estimate emissions for ANS and Wyoming crude oils. The GHG emissions for the other crude oils listed in Table 31 are from the original source.

The fuel chain for petroleum is similar to that shown for FT fuels in Figure 1 of Section 2, the major difference being that petroleum crude oil may be transported long distances prior to being refined into finished products. Crude oil transportation and refined-product transportation and distribution have been combined in Table 31. Again, transportation is a modestly significant source of emissions when crude oil is transported long distances (e.g. 26 g CO_2-eq/mile for Arab Light). Thus, in a carbon-constrained world, it may not make environmental sense to move oil (or any other commodity) halfway around the world.

There are significant differences between the GHG emissions for transportation from the McCann analysis relative to the FT LCI estimated here (e.g., 8 g CO_2-eq/mile for transporting Wyoming crude vs. 2 g/mile for FT syncrude from Wyoming coal). No explanation of these differences is possible without details of the McCann inventory. However, it is possible that the private client information reveals larger emissions from real-world operations.

While combustion dominates total emissions for petroleum, other contributing sources are not insignificant. Conversion and refining emissions (74-143 g CO_2-eq/mile), the second largest contributor, vary with crude API gravity. The API gravity is inversely proportional to specific gravity. High API gravity (low specific gravity) crude oils are generally of higher quality than low API gravity crude oils, which are referred to as heavy crudes. Heavier crude oils require more upgrading and refining and produce less desirable by-products. Emissions associated with their end-use are also higher, reflecting the poorer quality of their products. While not evident from the crude oils listed, production/extraction emissions are also related to crude API gravity. Heavier oils require reservoir stimulation techniques (such as steam injection), which require significant expenditures of energy and produce additional GHG emissions. Arab Light crude oil is an exception to the rule. Its high emissions result from flaring and venting of associated gas, a potential feedstock for GTL.

Table 31: Full Life-Cycle GHG Emissions for Petroleum Diesel

(g CO_2-eq/mile in SUV)

Crude Oil (°API)	Extraction/ Production	Conversion/ Refining	Transport./ Distribution	End Use Combustion	Total Fuel Chain
Wyoming Sweet (40°)	23	74	8	363	468
Canadian Light	30	81	11	367	489
Brent North Sea (38°)	23	81	8	367	479
Arab Light (38°)	35	81	26	367	509
Alaska North Slope (26°)	28	101	14	378	522
Alberta Syncrude (22°)	32	104	10	370	516
Venezuelan Heavy Oil (24°)	32	108	13	382	534
Venezuelan Syncrude (15°)	32	143	10	390	574

Comparing Tables 28 and 31, the production of FT diesel from coal results in significantly higher GHG emissions than for petroleum-derived diesel (962-939 vs. 468-574 g CO_2-eq/mile). GTL technology can achieve GHG emissions levels between those for coal liquefaction and petroleum refining (562-652 g/mile), due to the higher hydrogen content of methane relative to petroleum (4 to 1 vs. ~2 to 1). In fact, for natural gas Scenario 4, the GHG emissions for FT diesel are lower than the emissions for Venezuelan syncrude (562 vs. 574 g/mile), which requires severe processing to make it suitable as a feedstock for refining. Sequestration of vented CO_2 and CO_2 from combustion (Scenarios 1c, 4c and 6c) may be able to reduce GHG emissions to levels below those for products from petroleum refining. If advanced diesel engines are considered, then Scenarios 1b, 4b and 6d may also achieve these low GHG emissions levels.

7.5 Strategies for Reducing GHG Emissions from the FT Fuel Chain

The GHG emission reduction strategies identified in Section 7.3 can be divided into two categories: upstream and end-use. *Upstream GHG reduction strategies* involve modifications to the indirect liquefaction process in order to remove and sequester CO_2 produced during conversion, co-produce fuels and power, substitute biomass feedstocks, or mitigate the direct venting and flaring of methane. *End-use GHG reduction strategies* involve improvements in the efficiency of the end-use fuel application. With improved fuel efficiency less fuel is consumed per mile and less fuel must be produced and transported. Examples include adoption of higher-efficiency conventional and advanced diesel engines for passenger transportation (as was considered above for SUVs) or radical changes to the vehicular power plant (such as adoption of fuel cell technology in vehicles). These changes may also impact the processing used to produce the fuel owing to changes in fuel characteristics that their adoption might involve. In the extreme, they could necessitate *fuel switching*, the substitution of a totally new or different fuel for a given engine application. This is the main argument for replacing gasoline-powered engines with diesel-powered engines in SUVs.

The GHG reduction scenarios outlined below consider combinations of upstream and end-use strategies identified in the sensitivity analysis to maximize reductions:

<u>GHG Reduction Scenario 7</u>

Production of FT fuels from domestic coal reserves at a mine-mouth location. Locally available biomass is co-processed by co-feeding 20% biomass (LHV-basis) with the coal to produce liquid fuels. Any coalbed methane emissions from the mine are captured and also co-fed to the FT plant. The FT plant design is based on once-through conversion of the syngas and co-production of fuels and electric power. A portion of the power is used in the FT plant, and a portion is directed to coal mining operations. The remainder is sold, possibly generating GHG emission reduction credits.

Emissions Estimate:	Basis (Scenario 1a)	939 g/CO_2-eq/mile
	Co-processing of biomass (1e)	-155
	Co-production of power (1d)	-304
	Coalbed methane capture (80% of 1f)	<u>- 18</u>
		462
	Adv. diesel engine (13% reduction)	<u>× .87</u>
		402

A potential reduction of 537 g/CO_2-eq/mile or 57%.

GHG Reduction Scenario 8

Production of FT fuels from domestic coal reserves at a mine-mouth location. Locally available biomass is co-processed by co-feeding 20% biomass (LHV-basis) with the coal to produce liquid fuels. Any coalbed methane emissions from the mine are captured and also co-fed to the FT plant. The FT plant design is based on recycle of the unconverted syngas to maximize the production of liquid fuels; however, some electric power is co-produced to satisfy the needs of the FT plant and coal mine. Emissions of greenhouse gases from the plant are minimized by sequestering CO_2 in aquifers or other formations. Oxygen is used for combustion, thus producing an additional concentrated CO_2 stream for sequestration. Oxygen required for gasification and combustion may be supplied by advanced oxygen separation technologies. CO_2 is used as a diluent during combustion to control furnace, boiler and turbine temperatures.

Emissions Estimate:	Basis (Scenario 1a)	939 g/CO_2-eq/mile
	Co-processing of biomass (1e)	-155
	Sequestration of process CO_2 (90% of 1b)	-404
	Sequestration of combustion CO_2 (80% of 1c-1b)	- 54
	Coalbed methane capture (80% of 1f)	- 18
		308
	Adv. diesel engine (13% reduction)	× .87
		268

A potential reduction of 671 g/CO_2-eq/mile or 71%.

GHG Reduction Scenario 9

Production of FT fuels from domestic coal reserves at a mine-mouth location. Any coalbed methane emissions from the mine are captured and co-fed to the FT plant, along with coalbed methane recovered from the surrounding region. Thus, a substantial fraction of the feed to the plant is methane and half the fuel product is produced from methane rather than coal. The FT plant design is based on recycle of the unconverted syngas to maximize the production of liquid fuels; however, some electric power is co-produced to satisfy the needs of the FT plant, coal mine and coalbed methane operations. Emissions of greenhouse gases from the plant are minimized by sequestering CO_2 in unmined coal seams, thus enhancing the recovery of coalbed methane. Oxygen is used for combustion, thus producing an additional concentrated CO_2 stream for sequestration. Oxygen required for gasification and combustion may be supplied by advanced oxygen separation technologies. CO_2 is used as a diluent during combustion to control furnace, boiler and turbine temperatures.

Emissions Estimate:	Basis (Scenario 1a)	939 g/CO_2-eq/mile
	Co-processing of coalbed methane with credit for gas transmission & processing (average of 4a-1a+.95×71)	-222
	Sequestration of process CO_2 (90% of average of 1b+4b)	-231
	Sequestration of combustion CO_2 (80% of average of (1c-1b)+(4c-4b))	- 98
	Coalbed methane capture (80% of average of 1f+0)	- 9
		379
	Adv. diesel engine (13% reduction)	× .87
		330

A potential reduction of 609 g/CO_2-eq/mile or 64%.

It is expected that with current technology, significant parasitic energy losses would result from sequestration and increased use of oxygen in the FT plant. For the above estimates, it was assumed that only 90% of the vented CO_2 could be captured and sequestered, 90% of the CO_2 from combustion could be captured (0.9 x 0.9 x 100% = ~80% captured and sequestered), and 80% of coalbed methane emissions from mining could be captured. It was further assumed that results from the biomass co-production Scenario 1e and the pipeline gas Scenario 4a could be used to estimate emissions for coal and biomass and coal and coalbed methane co-processing, respectively. Since utilizing coalbed methane will not require cross-country transportation and processing requirements are minimal, credit was given in this scenario for a 95% reduction in extraction/production emissions. The benefits of co-production are based on the natural gas co-production Scenario 6d. No credit has been taken for the sale of the power co-produced, even though, GHG emissions will be lower than those from a typical existing power plant.

The analysis given above only identifies what may be possible. While Scenario 8 shows the biggest GHG emissions reduction relative to the other Scenarios 7 and 9 (71% vs. 57 and 64%), too much uncertainty exists in these estimates to consider one scenario better than another. *Further in-depth analysis will be needed to accurately quantify the future scenarios developed above, and technology breakthroughs will be required in CO_2 sequestration, oxygen separation, and combustion technology to achieve these benefits.*

8.0 CONCLUSIONS & RECOMMENDATIONS

The results of the life-cycle inventory and sensitivity analysis presented in Section 7 raise a number of new questions:

- Can realistic processes be developed to reduce or eliminate GHG emissions from the production of FT fuels from fossil energy resources?
- What is the actual resource base available for co-processing coal and biomass, or coal and coalbed methane?
- How should emissions be allocated between co-produced fuels and power?
- Can GHG emissions reduction credits be realized by co-producing power, elimination of venting and flaring of natural gas/coalbed methane, etc.?
- What might these credits be worth in the future?
- What will the GHG emissions from petroleum refining look like in the future?
- What are the GHG emissions from other advanced vehicle technologies: advanced spark-ignition engines, fuel cells, hybrid-electric systems, etc.?
- How do CP emissions from FT production and end-use compare with existing systems?
- What about emissions of water and solid waste from the production of FT fuels?
- What are the future technology needs to realize these GHG reductions?
- What might this all cost?

In order to answer these questions, life-cycle emissions and economic issues will need to be further addressed. These issues are discussed in more detail below.

8.1 Life Cycle Assessment

Questions regarding the optimal allocation of emissions between co-produced fuels and power, and determination of GHG reduction credits were beyond the scope of this study. Answers will require the careful comparison of existing energy and fuel systems. The allocation procedure used here for scenarios involving the co-production of fuels and power is based on standard practice within the LCA community. However, it can in many cases result in as many problems with the analysis as it solves. *Decisions are always made between alternatives*. *A preferred approach, therefore, would be to consider avoided or incurred emissions* due to the net production or consumption of electric power relative to some other alternative for providing this power. If net power is consumed at the FT plant, then emissions incurred by offsite power generation are added to the FT plant emissions as was done here. If net power is produced at the FT plant, emissions avoided from offsite power generation are subtracted. Whether power production at the FT plant is beneficial or not then depends on the basis used for offsite power generation. *Details of such an approach should be pursued in any further investigations.*

A more complex variation of the allocation problem also arises when comparing FT fuels to petroleum-derived fuels, where not only may product qualities differ, but the finished product and by-product mix can be significantly different. It has been suggested [24] that the various by-products from petroleum refining (petroleum coke, LPG, home-heating oil, etc.) be debited to the premium products (gasoline, jet and diesel fuel) based on the assumption that natural gas could be substituted for these other fuels, if they were never produced. This same procedure could be used with FT fuels. Although, these problems were not considered in this LCI, they need to be addressed in the future.

It can also be foolhardy to only consider GHG emissions and ignore all other airborne, waterborne, or solid emissions. *Improvements relative to GHG reductions may very well be offset by other effects on the environment or human health and well being*. A preliminary inventory of upstream emissions from FT fuel production has been included here. Completing this inventory will require consideration of the end-use application, which in addition to SUVs, could include other gasoline or diesel powered vehicles or equipment, or even future hybrid or fuel cell powered vehicles. Analysis of fuel switching scenarios like these *will require expansion of the emissions inventory to future petroleum production and refining systems to establish a basis upon which to make comparisons of benefits and drawbacks.*

8.2 Economic Issues

It is clear that many of the GHG emissions reduction options considered here would be expensive to implement. Current estimates for the cost of indirect liquefaction (Bechtel ILBD) correspond to a required selling price for the FT products of roughly $1.24 per gal (1998 dollars before taxes and marketing charges). This price is based on updates (by E^2S-NETL) to the conceptual designs developed in the early 1990s. However, there is reason to believe that rapid technology improvement in oxygen separation, coal gasification, and FT conversion could lower this price by as much as $0.20 per gal. This, coupled with the premium which FT diesel is likely to command, puts FT fuels in a near-competitive range with petroleum-derived gasoline and diesel. *There is a need to update the analysis used to determine the required selling price and FT product premium to reflect current and future trends in transportation fuels markets.*

Recent DOE estimates for the cost of sequestration technologies (other than forest sinks) are well over $100 per ton of carbon sequestered. The estimates for future technologies under development range anywhere from $5 to $100 per ton ($1.4 to $27 per ton of CO_2). The DOE carbon sequestration program has a goal of driving down the cost of sequestration to $10 per ton through aggressive technology development. While the CO_2 emissions from indirect coal liquefaction are high, the process has a significant advantage in that CO_2 can be removed from the process as a concentrated stream that could easily be sequestered. Based on these estimates then, the cost of sequestration of process CO_2 from indirect liquefaction is about $0.33 per gal based on $100 per ton (0.449 kg CO_2/mile $\times$ 24.4 mile/gal $\times$ 2.2 lb/kg $\times$ 1 ton/2000 lb $\times$ 27 $/ton) and $0.02 per gal based on the DOE target of $10 per ton. *The broad range of this potential added cost, and the possibility that it could wipe-out the significant cost reductions obtained over the last decade, make it paramount that efforts to reduce the cost of FT conversion be continued.*

In the immediate future, only limited supplies of low-cost biomass are available for alternative uses. E^2S-NETL estimates the required selling price of FT fuels derived from biomass range anywhere from $2.00 to $2.31 per gal, depending on the source of the biomass. *Unless these costs can be reduced and the biomass resource base expanded, this option is likely to only play an incremental,* *albeit potentially important, role in GHG reduction strategies* (e.g., in meeting international targets). However, conversion of biomass to FT diesel, with the addition of sequestration of the concentrated CO_2 stream co-produced, is the only strategy when compared with those reported here that has the promising potential to be used as a "CO_2 sponge" to reduce atmospheric GHG levels. This scenario has not been considered here, but deserves future attention.

The optimum coupling of all three technologies: sequestration, co-production, and co-processing, may be a very attractive GHG mitigation strategy to minimize both GHG emissions and their cost impact on indirect liquefaction. Thus, there is a pressing need to carefully examine in detail both the technology options for GHG emissions reduction and their cost impact on the FT product.

8.3 Concluding Remarks

A Life-Cycle Inventory of greenhouse-gas emissions from FT fuel production has been completed. This analysis has identified and quantified the significant sources of GHG emissions from the FT fuel chain. Emissions from the FT conversion step can be comparable to those from end-use combustion. At the present, GHG emissions from the FT fuel chain are greater than those from the existing petroleum-based fuel chain. Coal-based conversion is at a significant disadvantage relative to petroleum; whereas, natural gas conversion is only moderately worse than the best petroleum refining, but better than the production and refining of heavy crude oils. In order for FT technology to be accepted in a world that is becoming more-and-more conscious of the effects of burning fossil fuels, it will be necessary to identify strategies and technologies for reducing GHG and other emissions. This study has been able to identify a number of possible approaches, including carbon sequestration, co-production of fuels and power, and co-processing of coal and biomass or coal and coalbed methane. Improvements in vehicle technology will also benefit the FT fuel chain by increasing fuel economy and, thus, reducing emissions per mile.

This analysis has also confirmed the findings of other researchers that extraction and transportation-related GHG emissions are much less than the emissions associated with conversion and end-use combustion of the fuel. However, this is not to say that these emissions categories should not be included in any full or streamlined LCI. These emissions can still be quite large relative to those from other industries and their reduction represent a significant challenge for coal, oil and gas production companies. Any analyst working outside of these organizations faces major challenges in identifying and quantifying all sources of emissions. Access to actual field data is necessary to accurately determine the true levels of emissions. Significant uncertainties still exist and too much credibility should not be given to absolute values. Relevant differences should provide reliable guidance to policy decisions.

In order to evaluate the full potential of GHG reduction strategies for FT fuel production, all of the options considered here require better data and a more rigorous analysis beyond the scope of this study. Neither has a total view of the environmental benefits and deficiencies of FT fuels been realized in this analysis. A GHG emissions inventory has been completed, but only the first step has been taken toward developing a complete life-cycle inventory of all FT fuel chain impacts. Emissions of criteria pollutants have been identified for combustion sources along the fuel chain.

Further work will be necessary to estimate emissions from vehicles fueled by FT diesel and gasoline and to expand this inventory to all categories of multimedia emissions.

This life-cycle greenhouse-gas emissions inventory for Fischer-Tropsch fuels is only the first phase of a comprehensive assessment to characterize the impact, both short and long term, of FT fuel production on the environment and on human health and well-being. Future research will be focused on expanding the current emissions inventory to include a broader range of multimedia emissions of interest to NETL programs, and on performing life-cycle inventory and economic analyses corresponding to the new low-emission FT process designs identified here.

GLOSSARY OF PROCESS TERMINOLOGY

Acid Gas – a gas stream containing a large percentage of H_2S and/or CO_2.

Alkylation – a refining process used to convert light hydrocarbon gases into a quality gasoline blending component.

Amine Absorption System – a process for removing H_2S and/or CO_2 from a gas stream by means absorption of the acid gas in an amine solvent (e.g., MDEA) which is continuously recycled and regenerated.

Associated Gas – methane and other light hydrocarbon gases recovered from petroleum production operations.

Autothermal Reforming – a process for producing syngas from pure methane or natural gas which combines partial oxidation and steam reforming reactions to balance heating and cooling requirements in the integrated system.

Biomass – any hydrogen and carbon containing substance produced by living or very recently living organisms.

Bituminous Coal – a rank of coal typically found in the eastern U.S. which is generally of moderate to good quality for combustion or liquefaction.

Catalytic Reforming – a refining technology used to convert low-quality naphtha into high-quality gasoline by removing hydrogen from hydrocarbons to form unsaturated ringed-compounds called aromatics.

Claus Unit – a process for converting H_2S into elemental sulfur.

Coal Ash – the mineral matter contained in coal.

Coalbed Methane – methane released from coal mining operations.

Coal Cleaning – processes for removing coal ash from coal.

Coal Preparation – processes for preparing coal for utilization either via combustion or liquefaction, including cleaning, drying and grinding.

Coal Rank – a relative rating scale for of coals which is indicative of the age, carbon content, volatile matter and heating value of the coal.

Combined-Cycle Power Plant – a power plant which produces electric power from an integrated gas and steam turbine system.

Crude Oil – a naturally occurring hydrocarbon-based oil.

Cryogenic Separation – separation processes which rely on differences in the volatility of compounds at temperatures significantly below ambient conditions.

Dehydration/Compression – a process for removing both heavier hydrocarbons and water from a gas stream.

Diesel Fuel – blends of hydrocarbon components with carbon numbers generally in the range of 16 to 18 that meet specifications for use in diesel-cycle (compression ignition) engines.

Distillate – a feed or intermediate stream that can be processed into components suitable for blending into jet or diesel fuel.

Field Condensate – a liquid hydrocarbon mixture produced at the natural gas wellhead.

Fischer-Tropsch Synthesis – a catalytic process for converting synthesis gas into liquid hydrocarbons.

Flared Gas – any gas stream that is produced from production, transportation or refining and processing which is incinerated before being discharged.

Fluid Catalytic Cracking – a refining process which converts oils into gasoline and diesel blending components by catalytically cracking large hydrocarbon molecules into smaller molecules in the absence of hydrogen in a fluidized bed reactor.

Fly Slag – coal ash removed from the syngas produced by gasification processes as small particles.

Fractionation – any physical separation process, such as distillation or extraction, used to separate individual or subgroups of components from a mixture.

Fuel Oil – any oil suitable for combustion in a conventional or advanced boiler system.

Gas Conditioning – the recovery of hydrocarbon liquids from a gas stream to make the gas suitable for transportation and sale.

Gasification – a process for producing syngas from a solid feedstock, such as coal or biomass, by reaction with oxygen and/or steam.

Gasoline – blends of hydrocarbon components generally with carbon numbers in the range of 5 to 10 that meet specifications for use in gasoline-cycle (spark ignition) engines.

Gas Plant – a plant which combines processes for the separation and purification of gas streams such as natural gas.

Gas Sweetening – the removal of H_2S and/or CO_2 from a gas stream to make the gas suitable for transportation and sale.

Gas-To-Liquids (GTL) – a process for converting natural gas to liquid fuels, such as FT liquids or methanol.

Hydrocracking – a refining process which converts oils into gasoline and diesel blending components by catalytically cracking large hydrocarbon molecules into smaller molecules in the presence of hydrogen.

Hydrolysis – processes that react gas impurities with water to facilitate their removal.

Hydrotreating – a refining process used to improve the quality of naphtha and distillate streams by adding hydrogen to the components of the stream.

Indirect Liquefaction – any process for converting a hydrogen and carbon containing solid or gas feedstock into a liquid which employs an intermediate step involving synthesis gas.

Isomerization – a refining process which converts straight-chain molecules to branched molecules.

Jet Fuel – blends of hydrocarbon components with carbon numbers generally in the range of 10 to 16 that meet specifications for use in turbine engines.

Liquefaction – processes for converting a solid or a gas to a liquid, refers both to chemical and physical conversions.

Liquefied Natural Gas (LNG) – a natural gas stream which has been refrigerated and compressed to make it liquid.

Liquefied Petroleum Gas (LPG) – a mixture of hydrocarbons that are gases at ambient conditions and are stored as liquids under pressure. Used here to specifically refer to mixtures of propane and propylene and mixtures of butenes and butanes.

Longwall Mining – a coal mining technique that removes all the coal from a coal seam inducing controlled ground subsidence.

Methyl-Diethanol Amine (MDEA) – a solvent used to remove H_2S and/or CO_2 from a gas stream.

Methyl Tert-Butyl Ether (MTBE) – an oxygen containing blending component for gasoline.

Naphtha – a feed or intermediate stream that can be processed into components suitable for blending into gasoline.

Natural Gas – a naturally occurring mixture of hydrocarbon gases.

Natural Gas Liquids (NGL) – propane, butanes and heavier hydrocarbons recovered from natural gas.

Natural Gasoline – pentane and heavier hydrocarbons recovered from natural gas.

Petroleum – any naturally occurring hydrocarbon-based liquid, including crude oils.

Partial Oxidation (POX) – a process for producing syngas from hydrocarbons which uses oxygen gas (from air) to supply oxygen to the reaction.

Pressure Swing Absorption (PSA) – a process used to recover hydrogen from a gas stream that employs a solid absorbent and operates cyclically.

Recycle Gas – unconverted synthesis gas which is returned to the FT reactor for further conversion.

Refining – integrated processes used to convert a crude or synthetic crude oil into salable products such as gasoline, jet and diesel fuel.

Residual Oil – the heavy oil remaining after the lighter products are distilled from crude oil.

Saturate – a hydrocarbon molecule that contains all aliphatic bonds.

Shell Claus Offgas Treating (SCOT) – a process used to convert sulfur in the tail gas back into H_2S for recycle to the Claus unit.

Scrubbing – a process that contacts raw syngas with water to remove entrained fine particulates.

Sequestration – the capture, concentration and long-term storage of CO_2.

Slag – coal ash removed from coal during gasification in a molten state and subsequently cooled to form a solid.

Slurry Bubble Column Reactor – a three-phase reactor for contacting syngas with catalyst.

Sour Water – an aqueous stream containing dissolved H_2S and/or CO_2.

Steam Reforming – a process for producing syngas from hydrocarbons which uses steam to supply oxygen for the reaction.

Strip Mining – a surface coal mining technique that removes the overlying soil and rock to expose the coal seam.

Stripping – a process for removing H_2S and/or CO_2 from an aqueous stream by distillation, including the regeneration step of an amine absorption system.

Subbituminous Coal – a rank of coal typically found in the western U.S. which is generally of low to moderate quality for combustion or liquefaction.

Supercritical Extraction – a fractionation process that employs a supercritical solvent to facilitate the absorption and separation of one component from another.

Synthetic Crude Oil or *Syncrude* – an oil which has been manufactured from alternative feedstocks which has properties similar to crude oil.

Synthesis Gas or Syngas – a mixture of hydrogen and carbon monoxide that can be chemically converted to liquid fuels or chemicals.

Tail Gas – the gas leaving a Claus unit which contains trace impurities that must be removed before venting.

Tert-Amyl Methyl Ether (TAME) – an oxygen containing blending component for gasoline.

Vented Gas – any gas stream that is produced from production, transportation or refining and processing which is directly discharged to the atmosphere.

Water Gas Shift – the reaction and reverse reaction of CO and H_2O to form H_2 and CO_2.

ZSM-5 Upgrading – a Mobil proprietary process that converts naphtha and distillate into components suitable for gasoline blending.

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APPENDIX A

Life-Cycle Greenhouse-Gas Emissions Inventory For Fischer-Tropsch Fuels

Example Calculations

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SECTION 1

INTRODUCTION

1. INTRODUCTION

Appendix A Objectives:

- Present the material and energy balance data from a conceptual process design developed for the DOE in the 1990s for coal liquefaction using Illinois #6 underground coal (Design Case 1 of 8)

- Present the emission data for all processes upstream and downstream of the FT conversion plant for Design Case 1. (i.e. ancillary emissions, end use combustion…)

- Present various assumptions and estimations made throughout the inventory analysis

- Present step-by-step sample calculations for Design Case 1 to illustrate the methods of estimating greenhouse gas emission data

A detailed analysis using only Design Case 1 of Scenario 1 (FT production from Illinois #6 coal for use in the Chicago area) is presented here. The same equations, assumptions, methodology, etc. can be applied to Scenarios 2 through 6. Most of the results for Scenarios 2 through 6 are also summarized with Scenario 1 throughout the Appendix.

Greenhouse Gases Considered:

- CO_2 (carbon dioxide) from syngas production, FT synthesis, fossil-fuel combustion along the life cycle, and venting from natural gas production.
- CH_4 (methane) from fugitive plant and pipeline emissions, incomplete combustion or incineration (gas flaring), and coalbed methane release.
- N_2O (nitrous oxide) from fuel combustion and cultivation of biomass.

Criteria Pollutants Considered

- CO (carbon monoxide)
- NOx (nitrogen oxides)
- SOx (sulfur oxides)
- VOC (Volatile Organic Compounds)
- PM (Particulate Matter)

SECTION 2

ANCILLARY EMISSIONS

2. ANCILLARY EMISSIONS

The ancillary feedstocks of interest for Design Case 1 of Scenario 1 (Illinois #6) are:

- Electricity for coal mining
- Electricity for FT production
- Electricity used for pipeline transportation of FT products
- Low sulfur distillate fuel oil (DFO) for tank truck distribution of FT products
- Fuel gas used in FT production
- Butanes for FT product upgrading
- High sulfur distillate fuel oil (RFO) for tanker transportation of FT products (not used in Scenario 1)

A. Electricity Emissions

Includes airborne emissions from extraction of the fossil fuel (upstream) and fuel combustion for power generation at the power plant (downstream).

STEP 1: Data Collection

Table A1: CO_2-Equivalent Emissions of Individual Greenhouse Gases from Power Plants and Upstream Processes (g CO_2-eq/kWh)
[20, pg. D-23], [22]

Electricity Source	Coal Boiler	Fuel Oil Boiler	NG Boiler	NG Turbine	Nuclear Power
Average Energy Mix	51%	3%	15%		20%
Upstream processes					
CH_4	65.7	7.9	16.3	16.3	2.7
N_2O	0.4	5.3	0.7	0.7	0.7
NMOCs	0.4	3.3	1.1	1.1	0
CO	0.3	1.5	0.4	0.4	0.1
NOx	5.9	20.6	21.9	21.9	4.6
CO_2	29.3	141.8	72.0	72.0	45.9
Power Plant					
CH_4	0.1	0.2	0.0	3.6	0.1
N_2O	16.3	10.0	9.8	9.8	3.3
NMOCs	0.1	0.3	0.1	0.3	0.1
CO	0.4	0.5	0.6	1.7	0.1
NOx	102.5	71.0	54.7	41.1	4.9
CO_2	1075.4	875.9	606.3	605.2	6.5
All non-CO_2 gases	119.5	82.0	65.2	56.4	8.4
CO_2	104.6	1017.7	678.3	677.2	52.4

Table A2: Global Warming Potential (GWP) Mass Equivalency Factors
(kg of Gas per kg of CO_2)
[20, pg. O-9]

Gas	Equivalency Factor
CO_2	1
CH_4	21
N_2O	310
CO	3
NOx	40
NMOCs	11

STEP 2: Use the CO_2-equivalent emissions (Table A1), including the Average Energy Mix, and the Mass Equivalency Factors (Table A2) to calculate the gas emissions on a g/kWh basis. Note that the emissions are allocated among the energy sources using the average energy mix.

Methane Example:

$$CH_4 CoalBoiler\ Upstream\,(gCH_4/kWh) = \left(\frac{65.7\,gCO_2 - eq/kWh}{21\,gCO_2 - eq/gCH_4}\right) = 3.13 \qquad \text{(Eq 2.1)}$$

*Consider average energy mix to calculate the total methane emissions from upstream processes in electricity production.

$$CH_4 TotalUpstream\,(gCH_4/kWh) = (0.51\times 3.13) + (0.03\times 0.38) + (0.15\times 0.78) + (0.20\times 0.13) \qquad \text{(Eq 2.2)}$$

$CH_4 TotalUpstream(gCH_4/kWh) = 1.75$

Use Eq 2.1 and Eq 2.2 to calculate the remaining upstream and downstream GHG emissions.

Table A3: Emissions of Individual Greenhouse Gases from Power Plants and Upstream Processes (g/kWh)

Electricity Source	Coal Boiler	Fuel Oil Boiler	NG Boiler	NG Turbine	Nuclear Power	Total w/Energy mix
Upstream processes						
CH_4	3.13	0.38	0.78	0.78	0.13	1.75
N_2O	0.0013	0.0171	0.0023	0.0023	0.0023	0.002
NMOCs	0.0364	0.300	0.100	0.100	0.00	0.043
CO	0.100	0.500	0.133	0.133	0.033	0.094
NOx	0.1475	0.515	0.548	0.548	0.115	0.198
SOx						0.0
CO_2	29.30	141.8	72.0	72.0	45.9	39.5
VOCs (NMOCs+CH_4)						37.26
Power Plants						
CH_4	0.005	0.010	0.000	0.171	0.005	0.004
N_2O	0.05	0.030	0.030	0.030	0.010	0.03
NMOCs	0.01	0.030	0.010	0.030	0.010	0.010
CO	0.133	0.167	0.200	0.567	0.033	0.111
NOx	2.56	1.775	1.368	1.028	0.123	1.60
SOx						Calculated
CO_2	1075	876	606	605	7	671
VOCs(NMOCs+CH_4)						0.014

STEP 3: Calculate the upstream and downstream SOx and PM emissions from power plants using a different data source. (Emission data was not available from reference [20])

SOx Electricity Emissions:

SOx upstream = na (Assume 0)
SOx combustion (lb/MMBtu) = 1.45 [21, pg. 16]
Electricity efficiency (Btu/kWh) = 10,500 [21, pg. 16]

$$SOxTotal\ (g/kWh) = \left(\frac{1.45 lbsSOx}{1e6 Btu}\right) \times \left(\frac{10{,}500\, Btu}{kWh}\right) \times \left(\frac{454\, g}{lb}\right) = 6.91 \quad \text{(Eq 2.3)}$$

PM Electricity Emissions:

PM upstream = na (Assume 0)
PM combustion (lb/MMBtu) = 0.4 [21, pg. 16]
Electricity efficiency (Btu/kWh) = 10,500 [21, pg. 16]

$$PMTotal\ (g/kWh) = \left(\frac{0.4 lbsPM}{1e6 Btu}\right) \times \left(\frac{10{,}500\, Btu}{kWh}\right) \times \left(\frac{454\, g}{lb}\right) = 1.91 \quad \text{(Eq 2.4)}$$

Table A4: Total Ancillary Emissions from Electricity Production (Extraction + Combustion)

Gas	g/kWh
CO_2	710.10
CH_4	1.76
N_2O	0.042
CO	0.205
NOx	1.80
SOx	6.9
VOC	1.81
PM	1.91

B. Distillate Fuel Oil (DFO) Emissions for Light Trucks

Distillate fuel oil is considered to be a low sulfur diesel fuel used for transporting FT fuels from the tank farm (Chicago) to local refueling stations (60-mile radius). The total distillate fuel oil emissions consist of DFO production (refining) emissions and combustion emissions. CH_4, N_2O, NOx, CO and VOC distillate fuel emission data were available in reference [20], otherwise CO_2, SOx and PM are calculated via other sources.

STEP 1: Data Collection. CH_4, N_2O, NOx, CO and VOC distillate fuel oil emissions below include the production and combustion of distillate fuel oil. For example, 4.3 g of methane is emitted per 1 million Btu distillate fuel oil used by light trucks for transportation.

CH_4 (g/MM Btu) = 4.3 or (0.00947 lb/MM Btu) [20, pg. A-10]
N_2O (g/MM Btu) = 2.6 or (0.00573 lb/MM Btu) [20, pg. A-10]
NOx (g/MM Btu) = 348 or (0.767 lb/MM Btu) [20, pg. A-10]
CO (g/MM Btu) = 466 or (1.028 lb/MM Btu) [20, pg. A-10]

*VOC (g/MM Btu) = 93 or (0.2053 lb/MM Btu) [20, pg. A-10]
*Includes CH_4 and NMHCs

STEP 2: Calculate the CO_2 emissions

*****Carbon = 19.95 MM tonne/Quadrillion Btu [6, pg. 30]
*At Full Combustion

$$DistCO_2(lb/MMBtu) = \left(\frac{19.95e6TonneC}{1e15Btu}\right)\times\left(\frac{2204.6lb}{Tonne}\right)\times\left(\frac{lbmolCO_2}{12.01lbCarbon}\right)\times\left(\frac{44lbCO_2}{lbmolCO_2}\right) = 161 \quad \text{(Eq 2.5)}$$

Assumption: Since only combustion emissions were available, the amount was increased by 10% to account for upstream emissions.

CO_2 Distillate Fuel Oil (g/MM Btu) = 80503 or (177.4 lb/MM Btu)

STEP 3: Calculate SOx emissions. This includes SOx from distillate production, combustion and refinery sulfur plant.

<u>SOx from combustion</u> = 72.64 g/MM Btu or (0.160 lb/MM Btu) [21, pg. 16]

Assumption: The SOx emissions from this reference is from <u>off-highway</u> diesel fuel, therefore only 20% of the total SOx combustion emissions will be considered since highway distillate fuels have lower sulfur specifications (~500 ppm).

<u>SOx from distillate fuel oil production (refining):</u>

Total refinery SOx (MM lb/year) = 2001 [21, pg.16]
Distillate fuel (MM bbl/year) = 126.7 [21, pg. 9]
Total refined products (MM bbl/year) = 657.7 [21, pg. 9]
Distillate fuel oil (MM Btu/bbl) = 5.825 [25]
Residual fuel oil (MM Btu/bbl) = 6.287 [25]

$$\%refineryDFO = \left(\frac{126.7MMBblDist/Year}{657.7MMBblTotal/Year}\right)\times 100 = 19.26 \quad \text{(Eq 2.6)}$$

Next, use this percentage and allocate the total SOx (2001 MM lb/year) to the distillate fuel oil pool.

$$SOxrefinery(lbSOx/Bbl) = \left(\frac{2001MMlbsTotalSOx}{Year}\right)\times\left(\frac{Year}{126.7MMBbl}\right)\times .1926 = 3.04 \quad \text{(Eq 2.7)}$$

$$SOxrefinery(gSOx/MMBtu) = \left(\frac{3.04lbsSOx}{bbl}\right)\times\left(\frac{454g}{lb}\right)\times\left(\frac{bblDistillate}{5.825MMBtu}\right) = 276.2 \quad \text{(Eq 2.8)}$$

<u>SOx from sulfur plant</u>:

Sulfur production (ton/day) = 26,466 or (9,660,090 ton/year) [21, pg. 5]
*SOx = 91.56 lb SO_2/tons sulfur produced [21, pg. 113]
*From SCOT process and incinerator exhaust
*Assume SO_2 = SOx

Determine the total SOx produced from the sulfur plant per year.

$$SOx(lb/Year) = \left(\frac{9660090tonSulfur}{Year}\right)\times\left(\frac{91.56lbSOx}{tonSulfur}\right) = 8.8e8 \quad \text{(Eq 2.9)}$$

Next, use the percentage of distillate (19.26%) and allocate total SOx produced per year to the distillate fuel oil pool.

$$SOxDistillate(lbSOx/bbl) = \left(\frac{8.8e8lbSOx}{Year}\right) \times 0.19 \times \left(\frac{Year}{126.7MMbblDistillateProduced}\right) = 1.34 \qquad \text{(Eq 2.10)}$$

$$SOxDistillate(gSOx/MMBtu) = \left(\frac{1.34lbSOx}{bblDistillate}\right) \times \left(\frac{454g}{lb}\right) \times \left(\frac{bblDistillate}{5.825MMBtu}\right) = 104.8 \qquad \text{(Eq 2.11)}$$

Total SO_2 distillate fuel oil emissions (Light Trucks):

Total (gSO_2/MM Btu) = refining emissions + sulfur plant + end use combustion
Total (gSO_2/MMBtu) = 276.2 + 104.8 + 72.6(0.20) = 395.5
Total (lbO_2/MMBtu) = 0.8711

STEP 4: Calculate the PM emissions from diesel end use combustion and production (refining) of distillate fuel oil using equations 2.6, 2.7, and 2.8.

PM from combustion:

PM combustion = 4.54 g/MM Btu or (0.01 lb/MM Btu) [21, pg. 16]

Assumption: The PM emissions in this reference is from off-highway diesel fuel, therefore only 20% of the total PM combustion emissions will be considered since highway distillate fuels have lower PM specifications.

PM from distillate fuel oil production (refining):

Total PM (MM lb/year) = 557 [21, pg.16]
Distillate fuel (MM bbl/year)= 126.7 [21, pg. 9]
Total refined products (bbl/year) = 657.7 [21, pg. 9]
Distillate fuel oil (MM Btu/bbl) = 5.825 [25]
Residual fuel oil (MM Btu/bbl) = 6.287 [25]

Use equations 2.7 and 2.8 to calculate the PM emissions from refining.
PM Refining (g/MM Btu) = 66.0

Total PM distillate fuel oil emissions (Light Trucks):

Total (g/MM Btu) = 66.8 or (0.1472 lb/MM Btu)

Table A5: Total Ancillary Emissions from Distillate Fuel Oil (Light Trucks) (Delivery + Consumption)

Gas	g/MM Btu
CO_2	80503
CH_4	4.3
N_2O	2.6
CO	466.4
NOx	348.3
SOx	395.5
VOC	93.2
PM	66.8

C. Distillate Fuel Oil Emissions for Heavy Equipment

This is assumed to be high sulfur diesel fuel used in heavy (off-highway) equipment for coal mining, etc. These values include emissions from distillate fuel production and combustion. The "Off-Highway" data from source [20, pg. A10] is used.

STEP 1: Data Collection

CH_4 (g/MM Btu) = 4.3 or (0.00947 lb/MM Btu)	[20, pg. A-10]
N_2O (g/MM Btu) = 2.0 or (0.004405 lb/MM Btu)	[20, pg. A-10]
CO (g/MM Btu) = 404.1 or (0.890 lb/MM Btu)	[20, pg. A-10]
NOx (g/MM Btu) = 936.5 or (2.063 lb/MM Btu)	[20, pg. A-10]
*VOC (g/MM Btu) = 68.4 or (0.15066 lb/MM Btu)	[20, pg. A-10]

*Includes CH_4 and NMHCs

STEP 2: Calculate the CO_2 emissions from distillate fuel production and combustion for <u>heavy equipment</u>.

Assumption: CO_2 emissions are the same for heavy equipment as those calculated above for light trucks.
*Same emission value as in step 2 of the distillate fuel (light truck) section.

CO_2 Distillate Fuel Oil (g/MM Btu) = 80503 or (177.4 lb/MM Btu)

STEP 3: Calculate SOx emissions. This includes SOx from distillate fuel production, combustion and refinery sulfur plant for <u>heavy equipment</u> use.

Assumption: SOx emissions from distillate fuel production and refinery sulfur plant is the same as for light trucks. Since off-highway has a higher sulfur specification (~5000 ppm), <u>total</u> combustion credit will be taken instead of using only 20% as for the light trucks.

Total SOx Distillate Fuel Oil (g/MM Btu) = 453.63 or (1.0 lb/MM Btu)

STEP 4: Calculate the PM emissions from delivery and consumption of distillate fuel (<u>heavy equipment</u>) using equations 2.6, 2.7, and 2.8 above.

Assumption: The same PM emissions will be generated for distillate fuel oil used by light trucks and heavy equipment <u>except</u> for combustion. The full PM value for combustion will be taken into consideration for the heavy equipment, but otherwise the same upstream production PM emissions are assumed to be equal.

Total PM Distillate Fuel Oil (g/MM Btu) = 70.54 or (0.1554 lb/MM Btu)

Table A6: Total Ancillary Emissions from Distillate Fuel Oil (Heavy Equipment) (Delivery + Consumption)

Gas	g/MM Btu
CO_2	80503
CH_4	4.3
N_2O	2.0
CO	404.1
NOx	936.5
SOx	453.6
VOC	68.4
PM	70.53

D. Residual Fuel Oil (RFO) Emissions:

This is assumed to be the high sulfur diesel (off-highway) used for the tanker shipment of FT diesel fuel. Although a tanker is not used in Scenario 1, the calculations are shown here.

STEP 1: Data Collection

CH_4 (g/MM Btu) = 15.2 or (0.03348 lb/MM Btu) [20, pg. A-10]
N_2O (g/MM Btu) = 2.0 or (0.004405 lb/MM Btu) [20, pg. A-10]
CO (g/MM Btu) = 303.0 or (0.6674 lb/MM Btu) [20, pg. A-10]
NOx (g/MM Btu) = 818.2 or (1.8022 lb/MM Btu) [20, pg. A-10]
*VOC (g/MM Btu) = 151.6 or (0.3339 lb/MM Btu) [20, pg. A-10]
*Includes CH_4 and NMHCs

STEP 2: Calculate the CO_2 emissions from residual fuel oil production and combustion for <u>tanker transportation</u>.

*****Carbon = 21.49 MM tonne/Quadrillion Btu [6, pg. 30]
*At Full Combustion

$$RFOCO_2(lb/MMBtu) = \left(\frac{21.49e6TonneC}{1e15Btu}\right)\times\left(\frac{2204.6lb}{Tonne}\right)\times\left(\frac{lbmolCO_2}{12.01lbCarbon}\right)\times\left(\frac{44lbCO_2}{lbmolCO_2}\right) = 173.6 \quad \text{(Eq 2.12)}$$

Assumption: Since only combustion emissions were available, the amount was increased by 10% to account for upstream emissions.

CO_2 Residual Fuel Oil (g/MM Btu) = 86680 or (190.9 lb/MM Btu)

STEP 3: Calculate the SOx emissions. Use equations 2.6 to 2.11 and same methodology as used for the distillate fuel oil in light trucks.

<u>SOx from RFO combustion</u>:
SOx combustion (g/MM Btu) = 771.8 or (1.70 lb/MM Btu) [21, pg. 16]

SOx from RFO production (refining):

Total SOx (MM lb/year) = 2001 [21, pg16]
Residual Fuel (MM bbl/year) = 45.9 [21, pg. 9]
Total Refined Products (MM bbl/year) = 657.7 [21, pg. 9]
Distillate Fuel Oil (MM Btu/bbl) = 5.825 [25]
Residual Fuel Oil (MM Btu/bbl) = 6.287 [25]

Use equations 2.6, 2.7 and 2.8 to calculate the SOx in the residual fuel oil.

SOx RFO Production (g/MM Btu) = 219.7 or (0.48392 lb/MM Btu)

SOx from Sulfur Plant:

Sulfur (ton/day) = 26,466 or 9,660,090 ton S produced/year [21, pg. 5]
*SOx = 91.56 lb SO_2/tons Sulfur produced [21, pg. 113]
*From SCOT process and Incinerator Exhaust
*Assume SO_2 = SOx

SOx Sulfur Plant (g/MM Btu) = 97.13 or (0.2139 lb/MM Btu)

Total residual fuel oil SO_2 Emissions:
Total SO_2 residual fuel oil (g/MM Btu) = 1088.1 or (2.396 lb/MM Btu)

STEP 4: Calculate the PM emissions from delivery and consumption of residual fuel oil using equations 2.6, 2.7, and 2.8.

PM combustion:
PM combustion (g/MM Btu) = 36.32 or (0.080 lb/MM Btu) [21, pg. 16]

PM from residual fuel oil production (refining):

Total PM (MM lb/year) = 557 [21, pg16]
Residual fuel (MM bbl/year) = 45.9 [21, pg. 9]
Total refined products (MM bbl/year) = 657.7 [21, pg. 9]
Distillate fuel oil (MM Btu/bbl) = 5.825 [25]
Residual fuel oil (MM Btu/bbl) = 6.287 [25]

Use equations 2.6, 2.7 and 2.8 to calculate the PM emissions from residual fuel oil production/refining.

PM RFO Production (g/MM Btu) = 61.17

Total PM emissions from residual fuel oil:
PM Total = PM RFO Combustion + PM RFO Production
PM Total = 97.5 g/MM Btu or (0.21476 lb/MM Btu)

Table A7: Total Ancillary Emissions from Residual Fuel Oil (Delivery + Consumption)

Gas	g/MM Btu
CO_2	86680
CH_4	15.2
N_2O	2.0
CO	303
NOx	818.2
SOx	1088
VOC	151.6
PM	97.5

E. Fuel Gas Ancillary Emissions

This is the fuel gas consumed in the FT plant. Does not consider production.

STEP 1: Data collection.

CO_2 (g/MM Btu) = 56,029 or (123.4 lb/MM Btu) [20, pg. A-10]
CH_4 (g/MM Btu) = 1.3 or (0.000286 lb/MM Btu) [20, pg. A-10]
N_2O (g/MM Btu) = 2.0 or (0.0044 lb/MM Btu) [20, pg. A-10]
CO (g/MM Btu) = 15.4 or (0.035 lb/MM Btu) [20, pg. A-10]
NOx (g/MM Btu) = 63.6 or (0.1400 lb/MM Btu) [21, pg. 16]
VOC (g/MM Btu) = 2.7 or (0.004 lb/MM Btu) [21, pg. 16]
SOx (g/MM Btu) = 0.00 [21, pg. 16]
PM (g/MM Btu) = 1.36 or (0.003 lb/MM Btu) [21, pg. 16]

Table A8: Total Ancillary Emissions from Fuel Gas Consumption

Gas	g/MM Btu
CO_2	56,029
CH_4	1.3
N_2O	2.0
CO	15.4
NOx	63.6
SOx	0.0
VOC	2.7
PM	1.36

F. Butane Emissions

Butane is produced from natural gas; therefore the emissions are based off the associated natural gas emissions.

STEP 1: Obtain NG upstream production pipeline emissions.

Assumption: Natural gas extraction emissions are the same for butane production as for electricity generation. Convert natural gas pipeline emissions (Table A3) from kWh to MM Btu by using an efficiency conversion factor of 11314 Btu/kWh (as per reference).

Table A9: Natural Gas Pipeline Emissions

Gas	g/kWh	g/MM Btu
CH_4	0.78	69
N_2O	0.0023	0.20
CO	0.133	11.8
NOx	0.548	48.4
SOx	0.002	0.212
CO_2	72.0	6364
VOCs	.8762	77
PM	0	0

STEP 2: Calculate the Associated Natural Gas (ANG):

Assumption: CO_2, N_2O, CO, NOx, SOx, VOC, and PM associated natural gas emissions are 69.6% of the pipeline natural gas and CH_4 is 33.3 % of the pipeline natural gas.

Table A10: Associated Natural Gas (ANG) Emissions

Gas	g/MM Btu
CO_2	4427
CH_4	22.8
N_2O	0.146
CO	8.2
NOx	33.7
SOx	.147
VOC	53.6
PM	0

STEP 3: Calculate the emissions associated with the butane transportation.

The associated natural gas emissions will be combined with the butane transportation emissions (Table A5-light trucks).

Data:

Butane (MM Btu/Bbl) = 4.023 [26]

Butane density (lb/gal) = 5.007 [26]

Kansas to So. Illinois (miles) = 500

Trucking Energy Consumption (Btu/ton-mile) = 1900 [20, pg. E-9]

CO_2 Distillate Fuel Oil (g/MM Btu) = 80503 or (177.4 lb/MM Btu)

Transportation:

$$Emissions(g/galBut) = (EnergyConsumed)\times(Dist.)\times(Dens.)\times(Emissions)\times(Conv.Fact) \quad \text{(Eq 2.13)}$$

Example: Carbon dioxide emission from butane transportation.

$$TruckCO_2(g/galBut) = (1900)\times(500)\times(1/2000)\times(5.007)\times(177.4/1e6)\times(454) = 191 \quad \text{(Eq 2.14)}$$

Table A11: Butane Transportation Emissions

Kansas to Southern Illinois (500 miles)

Gas	g/gal Butane delivered
CO_2	191
CH_4	.012
N_2O	.0062
CO	.03898
NOx	.15117
SOx	.17276
VOC	.00216
PM	.01080

STEP 4: Combine emissions from butane production via associated natural gas (Table A10) and butane transportation emissions from Kansas to Southern Illinois.

Example: Total CO_2 emissions from butane production and delivery

$$Total(gCO_2/bbl) = \left(\left(\frac{191gCO_2}{gal}\right)\times\left(\frac{42gal}{bbl}\right)\right)+\left(\left(\frac{4427gCO_2}{MMBtu}\right)\times\left(\frac{4.023MMBtu}{bbl}\right)\right) = 25859 \quad \text{(Eq 2.15)}$$

Table A12: Total Ancillary Emissions from Butane Production and Delivery

Gas	g/bbl Butane delivered
CO_2	25859
CH_4	92
N_2O	0.84
CO	34.7
NOx	141.8
SOx	8.1
VOC	215
PM	6.7

G. Ancillary Emissions Summary

*Does not include methanol emissions since they are not used in Scenario 1. Same as Table 24 in main report.

Table A13: Emissions Inventory for Ancillary Feedstocks

	Electricity	Diesel Truck	Heavy Equip.	Tanker	Fuel Gas	Butane
	Delivered	Delivered & Consumed	Delivered & Consumed	Delivered & Consumed	Consumed	Delivered
	(g/kWh)	(g/MM Btu)	(g/MM Btu)	(g/MM Btu)	(g/MM Btu)	(g/bbl)
MM Btu/bbl	-	5.83	5.83	6.29	-	5.023
CO_2	710.54	80503	80503	86680	calculated	25859
CH_4	1.756	4.3	4.3	15.2	1.3	92
N_2O	0.0421	2.6	2	2	2.0	0.84
SOx	6.92	395.5	453.63	1088	0.0	8.1
NOx	1.8	348.3	936.5	818.2	63.6	141.8
CO	0.205	466.4	404.1	303	15.4	34.7
VOC	1.81	93.2	68.4	151.6	2.7	215
PM	1.91	66.9	70.53	97.49	1.36	6.7

SECTION 3

FISCHER-TROPSCH PROCESS

3. FISCHER-TROPSCH PROCESS

A. Resource Consumption & Yields for FT Production

Material and energy balance data from the eight indirect liquefaction baseline designs (ILBD) developed by Bechtel (see main report) were used to generate the resource consumption and yield data for each FT scenario studied. The ILBD data is summarized in Table 2 of the main report. This baseline design data provides the groundwork required to inventory the GHG emissions for the FT conversion process.

FT Product Basis—1bbl of FT C3+ liquid product contains:

- C_3/C_4 LPG
- Gasoline/Naphtha
- Distillate

STEP 1: Data collection. Obtained from the Indirect Liquefaction Baseline Design study done by Bechtel [7].

Table A14: Design Case 1 of Scenario 1 Fischer-Tropsch Material Balance Input Data [7]

	Ton/day	Bbl/day
Raw Materials		
Illinois #6 Coal:	18575	
Catalyst & Chemicals:	342	
Products		
LPG:	171	1922
Butanes:	-317	-3110
Gasoline/Naphtha:	3021	23943
Distillate:	3343	24686
Other Out Flows		
Slag:	2244	
Sulfur:	560	
CO_2 Removal:	28444	
CO_2 Gasifier Carrier Gas:	-3715	
S-Plant Flue Gas:	1086	
Utilities		
Electric Power (MW):	54	
Raw Water Make-Up (MM Gal/day):	14.46	

STEP 2: Calculate the resource consumption per barrel of FT liquid product. Recall that the liquid FT product includes C3/C4 LPG, gasoline/naphtha, and distillate.

$$Coal\,(ton/bblFT) = \frac{18575\,ton/day}{(1922+23943+24686)bbl/day} = 0.36745 \quad \text{(Eq 3.1)}$$

$$Butanes\,(bbl/bblFT) = \frac{-(-3110)}{1922+23943+24686} = 0.062 \quad \text{(Eq 3.2)}$$

$$Cat\,\&\,Chem(lb/bblFT) = \frac{342\times 2000}{1922+23943+24686} = 13.52 \quad \text{(Eq 3.3)}$$

$$RawWater\,(gal/bblFT) = \frac{14.46e6}{1922+23943+24686} = 286 \quad \text{(Eq 3.4)}$$

$$Power\,(kWh/bblFT) = \frac{54\times 1000\times 24}{1922+23943+24686} = 25.79 \quad \text{(Eq 3.5)}$$

STEP 3: Calculate the volume yield of each product per barrel of total FT liquid product.

$$C_3/C_4(bbl/bblFT) = \frac{1922\,bbl/day}{(1922+23943+24686)bblFT/day} = 0.038 \quad \text{(Eq 3.6)}$$

$$Gas/Nap\,(bbl/bblFT) = \frac{23943}{1922+23943+24686} = 0.474 \quad \text{(Eq 3.7)}$$

$$Distillate\,(bbl/bblFT) = \frac{24686}{1922+23943+24686} = 0.488 \quad \text{(Eq 3.8)}$$

STEP 4: Calculate the mass yield per barrel of FT liquid product.

$$C_3/C_4(ton/bblFT) = \frac{171}{1922+23943+24686} = 0.003 \quad \text{(Eq 3.9)}$$

$$Gas/Nap\,(ton/bblFT) = \frac{3021}{1922+23943+24686} = 0.062 \quad \text{(Eq 3.10)}$$

$$Distillate\,(ton/bblFT) = \frac{3343}{1922+23943+24686} = 0.066 \quad \text{(Eq 3.11)}$$

$$Slag\,(ton/bblFT) = \frac{2244}{1922+23943+24686} = 0.044 \quad \text{(Eq 3.12)}$$

$$Sulfur\,(ton/bblFT) = \frac{560}{1922+23943+24686} = 0.011 \quad \text{(Eq 3.13)}$$

STEP 5: Use the lower heating values of to calculate the energy yield per barrel of FT liquid product.

Table A15: Lower heating values (LHV)
[7]

	M Btu/lb
Coal:	11.95
Butanes:	19.6
LPG:	19.9
Gasoline/Naphtha:	17.7
Distillate:	18.9

$$Coal_{LHV}(MMBtu/day) = \left(\frac{18575\,toncoal}{day}\right) \times \left(\frac{2000\,lb}{ton}\right) \times \left(\frac{119500\,Btu}{lb}\right) \times \left(\frac{1}{1e6}\right) = 443744 \quad \text{(Eq 3.14)}$$

$$C_3/C_{4\,LHV}(MMBtu/day) = \frac{171 \times 2000 \times 19.9}{1000} = 6816 \quad \text{(Eq 3.15)}$$

$$Butane_{LHV}(MMBtu/day) = \frac{-317 \times 2000 \times 19.6}{1000} = -12448 \quad \text{(Eq 3.16)}$$

$$Gas/Nap_{LHV}(MMBtu/day) = \frac{3021 \times 2000 \times 17.7}{1000} = 107185 \quad \text{(Eq 3.17)}$$

$$Distillate_{LHV}(MMBtu/day) = \frac{3343 \times 2000 \times 18.9}{1000} = 126365 \quad \text{(Eq 3.18)}$$

*Divide the energy content of each product by the total FT liquid product.

$$C_3/C_4(MMBtu/bblFT) = \frac{6816}{(1922 + 23943 + 24686)} = 0.135 \quad \text{(Eq 3.19)}$$

$$Gas/Nap(MMBtu/bblFT) = \frac{107185}{(1922 + 23943 + 24686)} = 2.12 \quad \text{(Eq 3.20)}$$

$$Distillate(MMBtu/bblFT) = \frac{126365}{(1922 + 23943 + 24686)} = 2.50 \quad \text{(Eq 3.21)}$$

STEP 6: Calculate the thermal efficiency per barrel of FT liquid product.

$$TotalFT_{LHV} = LPG_{LHV} + Butane_{LHV} + Gas/Nap_{LHV} + Distillate_{LHV} \quad \text{(Eq 3.22)}$$

$$TotalFT_{LHV}(MMBtu/day) = 6816 - 12448 + 107185 + 126365 = 227919 \quad \text{(Eq 3.23)}$$

FT process power required (used):

$$Power_{LHV}(MMBtu/day) = \frac{54\,MW \times 24\,hr/day}{0.2930711\,MW/MMBtu/hr} = 4449 \quad \text{(Eq 3.24)}$$

$$ThermalEffciency(\%) = \frac{TotalFT_{LHV} - Power_{LHV}}{Coal_{LHV}} \quad \text{(Eq 3.25)}$$

$$Option1ThermalEffciency(\%) = \frac{227919 - 4449}{443744} \times 100 = 50.4\%$$

STEP 7: Calculate the carbon efficiency per barrel of FT liquid product.
The carbon efficiency for each case is calculated from the carbon balance data around the FT plant.

Case 1 carbon efficiency (coal):
Carbon out = 5292.8 ton/day [7]
Carbon in = 13190.1 ton/day [7]

$$CarbonEff.\ (\%) = \frac{Cout}{Cin} \times 100 \qquad \text{(Eq 3.26)}$$

Case 1 carbon efficiency (%) = 40.1

*This method is used to determine the carbon efficiencies for Design Cases 2, 3 & 4.

Case 5 carbon efficiency (biomass):

$$CarbonIN\ (ton/bblFT) = \left(\frac{0.621\, tonBiomass\ \ Feed}{bblFT}\right) \times \left(\frac{0.49\, tonC\ *}{tonBiomass}\right) = 0.3043 \qquad \text{(Eq 3.27)}$$

*0.49tonC/tonBiomass is from Table A36: Ultimate Analysis

$$CarbonOUT\ (ton/bblFT) = \left(\frac{131\, ton}{day}\right) \times \left(\frac{day}{157\, bblFT}\right) = 0.1132 \qquad \text{(Eq 3.28)}$$

Case 5 carbon efficiency (%) = 37.2

Case 6 carbon efficiency (pipeline gas):

$$CarbonIN\ (ton/bblFT) = \left(\frac{8.927\, Mscf}{bblFT}\right) \times \left(\frac{8949\, tonNG\ /day}{412000\, Mscf\ /day}\right) = 0.193902 \qquad \text{(Eq 3.29)}$$

$$CarbonOUT\ (ton/bblFT) = \left(\frac{4971\, ton}{day}\right) \times \left(\frac{day}{44602\, bblFT}\right) = 0.111452 \qquad \text{(Eq 3.30)}$$

Case 6 carbon efficiency (%) = 57.5
*Design Cases 7 and 8 (Associated NG) use the same method and equations as for Design Case 6.

Table A16: Resource Consumption and Yields for FT Production
(Per bbl of FT Liquid Product)

	Case 1	Case 2	Case 3	Case 4	Case 5[1]	Case 6[1]	Case 7	Case 8[1]
Feedstock	IL #6	IL #6	IL #6	Wyo. Coal	Biomass	Pipeline Gas	Assoc. Gas	Assoc. Gas
Upgrading	Maximum Distillate	Increased Gasoline	Maximum Gaso. & Chem.	Maximum Distillate	Fuels & Power	Maximum Distillate	Minimum Upgrading	Min. Upgrading & Power
Resources								
Coal or Biomass (MF ton)	0.3675	0.3661	0.3310	0.395	0.621 [0.00072]			
Natural Gas (Mscf)						8.927 [0.018]	10.305	10.325 [0.012]
Butanes (bbl)	0.062		0.093	0.062		0.008		
Methanol (bbl)			0.041					
Catalysts & Chemicals (lb)	13.52	15.44	na	15.71	na	0.13	na	na
Water Make-Up (gal)	286	285	279	196	541 [0.629]	455 [0.923]	114	91 [0.105]
Electric Power (kWh)[2]	25.79	24.87	24.87	42.12	-1781	-13.2		-230
Volume Yield (bbl)								
C3/C4 LPG	0.038	0.071	0.118	0.038		0.038		
Gasoline/Naphtha	0.474	0.616	0.708	0.474	0.330	0.379	0.313	0.312
Distillates	0.488	0.313	0.174	0.488	0.670	0.583	0.687	0.688
Mass Yield (ton)								
C3/C4 LPG	0.003	0.007	0.011	0.003		0.003		
Gasoline/Naphtha	0.060	0.077	0.089	0.060	0.042	0.048	0.038	0.038
Distillates	0.066	0.043	0.023	0.066	0.091	0.079	0.092	0.092
Slag (MF)	0.044	0.044	0.040	0.035	0.065 [0.000075]			
Sulfur	0.011	0.011	0.010	0.002				
Energy Yield (MMBtu)								
C3/C4 LPG	0.135	0.262	0.422	0.134		0.134		
Gasoline/Naphtha	2.120	2.764	3.019	2.121	1.463	1.687	1.439	1.433
Distillates	2.500	1.611	0.862	2.498	3.427	2.979	3.495	3.494
Power [3]					10.128	0.128		1.309
Allocation to Fuels					0.326	0.974		0.790
Carbon Efficiency (%)	40.1	41.1	37.7	39.1	37.2	57.0	39.3	39.2
Thermal Efficiency (LHV)	50.4%	52.0%	47.4%	49.3%	51.0%	59.1%	57.3%	57.1%

1 Values in [ ] are allocations per kWh of electricity produced and sold. All other values are per bbl.

2 Positive value is purchase, negative value is sale.

3 Energy content of fuel used to produce power for sale.

B. Emissions Inventory for Fischer-Tropsch Production

STEP 1: Perform a carbon balance around the FT process to determine <u>all</u> GHG emissions.

*Note: Ultimate analysis data on FT feedstocks and FT products are contained in Table A36 at the end of Appendix A and is used throughout the following calculations.

$$C_{coal}(ton/day) = \frac{Coal_{Feed}\ ton/day \times \%Carbon}{100} \quad \text{(Eq 3.31)}$$

$$C_{coal}(ton/day) = \frac{18575 ton/day \times 71.01}{100} = 13190 \quad \text{(Eq 3.32)}$$

$$C_{LPG}(ton/day) = \frac{171 \times 81.72}{100} = 139.7 \quad \text{(Eq 3.33)}$$

$$C_{Butanes}(ton/day) = \frac{-317 \times 82.66}{100} = -262 \quad \text{(Eq 3.34)}$$

$$C_{Gas/Nap}(ton/day) = \frac{3021 \times 85.63}{100} = 2586.9 \quad \text{(Eq 3.35)}$$

$$C_{Distillate}(ton/day) = \frac{3343 \times 84.6}{100} = 2828.2 \quad \text{(Eq 3.36)}$$

$$C_{Slag}(ton/day) = \frac{2244 \times 3.36}{100} = 75.4 \quad \text{(Eq 3.37)}$$

$$C_{CO_2Vented}(ton/day) = \frac{(CO_2Removed - CO_2CarrierGas) \times \%C_{CO_2}}{100} \quad \text{(Eq 3.38)}$$

$$C_{CO_2Vented}(ton/day) = \frac{(28444 + (-3715)) \times 27.29}{100} = 6749 \quad \text{(Eq 3.39)}$$

$$C_{CO_2Misc}(ton/day) = \frac{0.01 \times 28444 \times 27.29}{100} = 77.6 \quad \text{(Eq 3.40)}$$

$$C_{S-PlantFlu}(ton/day) = \frac{1086 \times 24.93}{100} = 270.7 \quad \text{(Eq 3.41)}$$

The remaining carbon is from fuel gas combustion.

$$C_{GasCombustion}(ton/day) = C_{Coal} - C_{FTLTotal} - C_{Slag} - C_{CO_2Vented} - C_{CO_2Misc.} - C_{S-Plant} = 725 \quad \text{(Eq 3.42)}$$

Table A17: Carbon Balance around FT Plant
(Design Case 1-Illinois #6 Coal)

Feedstock	**Carbon (ton/day)**
IL #6 Coal	13190
Energy Products	
LPG	139.7
Butanes	-262.0
Gasoline/Naphtha	2586.9
Distillates	2828.2
Total FTL	5292.8
Other Outflows	
Slag	75.4
Balance of Carbon	7821.9
CO_2 Vented (net removed)	6748.5
CO_2 Misc. Emissions	77.6
S-Plant Flue Gas	270.7
Fuel Gas Combustion	725.1

STEP 2: Combine the carbon balance data (Table A17) and ancillary emissions data (Table A13) to determine the FT process GHG emissions

Carbon Dioxide Emissions:

CO_2 sources:

1. Venting
2. Misc. sources
3. Sulfur Plant
4. Fuel gas Combustion
5. Power
6. Butane

$$CO_{2\,Vented}\ (g/day) = \left(\frac{44.01}{12.01}\right)\times 6749\ tonC\ \times\left(\frac{453.6g}{lb}\right)\times\left(\frac{2000\ lb}{ton}\right) = 2.24e10 \quad \text{(Eq 3.43)}$$

$$CO_{2\,Fugitive}(g/day) = \left(\frac{44.01}{12.01}\right)\times 77.6tonC\times\left(\frac{453.6g}{lb}\right)\times\left(\frac{2000lb}{ton}\right) = 2.58e8 \quad \text{(Eq 3.44)}$$

$$CO_{2\,S-Plant}\ (g/day) = \left(\frac{44.01}{12.01}\right)\times 270.7tonC\ \times\left(\frac{453.6g}{lb}\right)\times\left(\frac{2000\ lb}{ton}\right) = 8.99e8 \quad \text{(Eq 3.45)}$$

$$CO_{2\,FuelGas}\ (g/day) = \left(\frac{44.01}{12.01}\right)\times 725.1tonC\ \times\left(\frac{453.6g}{lb}\right)\times\left(\frac{2000\ lb}{ton}\right) = 2.41e9 \quad \text{(Eq 3.46)}$$

$$CO_{2\,Power}\ (g/day) = 710.54g/kWh\times 54.32e6W\times 1000\times\left(\frac{24hr}{day}\right) = 9.26e8 \quad \text{(Eq 3.47)}$$

*****Ancillary CO_2 for power = 710.54 g/kWh

$$CO_{2\,Butanes}\ (g/day) = -(42gal/bbl)\times(615.69g/galButane)\times(-3110bblButane/day) = 8.04e7 \quad \text{(Eq 3.48)}$$

CO_2 Total (g/day) = 2.7e10

$$CO_2(g/bblFTProduced) = \left(\frac{2.70e10}{1922+23943+24686}\right) = 534311 \quad \text{(Eq 3.49)}$$

Methane Emissions:

CH_4 sources:

1. FT Plant fugitive, tank, and flaring emissions
2. FT Plant fuel combustion
3. Power
4. Butanes

Data:

Fuel Consumption LHV (MM Btu/hr): 1125.5 or (27012 MMBtu/day) [7]
Fuel gas HHV (M Btu/lb): 5.18 [7]
Fuel gas LHV (M Btu/lb): 4.74 [7]
CH_4 (fugitive, tanks, flaring)(g/day) = 349081 [7]

$$FuelConsumptionHHV\ (MMBtu\ /\ day) = 27012 \times \left(\frac{FuelHHV}{FuelLHV} \right) \quad \text{(Eq 3.50)}$$

$$FuelConsumptionHHV\ (MMBtu\ /\ day) = 27012 \times \left(\frac{5.18}{4.74} \right) = 29519 \quad \text{(Eq 3.51)}$$

$$CH_{4\,FuelCombustion}\ (g\ /\ day) = 27012 \times 1.3 = 35116 \quad \text{(Eq 3.52)}$$

*Ancillary CH_4 for power = 1.3 g CH_4/MM Btu

$$CH_{4\,Power}\ (g\ /\ day) = 1.756 gCH_4\ /\ kWh \times 54.3 MW \times 1000 \times 24 hrs\ /\ day = 2.29e6 \quad \text{(Eq 3.53)}$$

$$CH_{4\,Butanes}\ (g\ /\ day) = 92 gCH_4\ /\ bblButane \times 3110 bbl\ /\ day = 286058 \quad \text{(Eq 3.54)}$$

$$CH_4 Total (g\ /\ day) = 349081 + 35116 + 2.29e6 + 286058 = 2.96e6 \quad \text{(Eq 3.55)}$$

$$CH_4 (g\ /\ bblFT) = \left(\frac{2.96e6}{1922 + 23943 + 24686} \right) = 58.6 \quad \text{(Eq 3.56)}$$

Nitrous Oxide Emissions:

N_2O sources:

1. FT Plant fuel gas combustion
2. Power
3. Butanes

$$N_2O_{FuelCombustion}\ (g\ /\ day) = 27012 \times 2.0 = 54024 \quad \text{(Eq 3.57)}$$

*Ancillary N_2O = 2.0 gN2O/MM Btu Fuel Combusted

$$N_2O_{Power}\ (g\ /\ day) = .0421 gN_2O\ /\ kWh \times 54.3 MW \times 1000 \times 24 hrs\ /\ day = 54890 \quad \text{(Eq 3.58)}$$

$$N_2O_{Butanes} (g\ /\ day) = (0.84 g\ /\ bblButane) \times (-3110 bbl\ /\ day) = 129.6 \quad \text{(Eq 3.59)}$$

$$N_2O Total (g\ /\ day) = 54024 + 54890 + 129.6 \cong 109043 \quad \text{(Eq 3.60)}$$

$$N_2O (g\ /\ bblFT) = \left(\frac{109043}{1922 + 23943 + 24686} \right) = 2.16 \quad \text{(Eq 3.61)}$$

Sulfur Oxides Emissions:

SOx sources:

1. Flue gas incineration
2. Power
3. Butanes

$$SOx_{FlueGas}(g/day) = FlueGasFlowrate \times \%Sulfur_{FlueGas}$$ (Eq 3.62)

$$SOx_{FlueGas}(g/day) = \left(\frac{1086tonFG}{day}\right) \times \left(\frac{.0005095lbS}{lbFG}\right) \times \left(\frac{2000lb}{ton}\right) \times \left(\frac{64.066lbSOx/lbmolSOx}{34.08lbS/lbmolSOx}\right) \times \left(\frac{453.6g}{lb}\right) = 943349$$ (Eq 3.63)

$$SOx_{Power}(g/day) = 6.92gSOx/kWh \times 54.3MW \times 1000 \times 24hr/day = 9022241$$ (Eq 3.64)

$$SOx_{Butanes}(g/day) = 8.1g/bbl \times 3110bbl/day = 25222$$ (Eq 3.65)

$$SOxTotal(g/day) = 943349 + 9022241 + 25222 = 9990812$$ (Eq 3.66)

$$SOx(g/bblFT) = \left(\frac{9990812}{1922 + 23943 + 24686}\right) = 197.6$$ (Eq 3.67)

Nitrogen Oxides Emissions:

NOx sources:

1. Fuel gas combustion
2. Power
3. Butanes

$$NOx_{FuelCombustion}(g/day) = 63.6g/bbl \times 27012bbl/day = 1715370$$ (Eq 3.68)

$$NOx_{Power}(g/day) = 1.8 \times 54.3MW \times 1000 \times 24hr/day = 2346826$$ (Eq 3.69)

$$NOx_{Butanes}(g/day) = 141.54g/bbl \times 3110bbl/day = 441033$$ (Eq 3.70)

$$NOxTotal(g/day) = 1715370 + 2346826 + 441033 = 4503229$$ (Eq 3.71)

$$NOx(g/bblFT) = \left(\frac{4503229}{1922 + 23943 + 24686}\right) = 89.1$$ (Eq 3.72)

Carbon Monoxide Emissions:

CO sources:

1. Fuel gas combustion
2. Power
3. Butanes

$$CO_{FuelCombustion}(g/day) = 15.4g/MMBtu \times 27012MMBtu/day = 416590 \quad \text{(Eq 3.73)}$$

$$CO_{Power}(g/day) = 0.205g/kWh \times 54.3MW \times 1000 \times 24hr/day = 267277 \quad \text{(Eq 3.74)}$$

$$CO_{Butanes}(g/day) = 34.7g/bbl \times 3110bbl/day = 107802 \quad \text{(Eq 3.75)}$$

$$COTotal(g/day) = 416590 + 267277 + 107802 = 791669 \quad \text{(Eq 3.76)}$$

$$CO(g/bblFT) = \left(\frac{791669}{1922 + 23943 + 24686}\right) = 15.7 \quad \text{(Eq 3.77)}$$

Volatile Organic Carbon Emissions:

VOC sources:

1. Fuel gas combustion
2. Power
3. Butanes

$$VOC_{FuelCombustion}(g/day) = 2.7g/MMBtu \times 27012MMBtu/day = 73516 \quad \text{(Eq 3.78)}$$

$$VOC_{Power}(g/day) = 1.81g/kWh \times 54.3MW \times 1000 \times 24hr/day = 2359864 \quad \text{(Eq 3.79)}$$

$$VOC_{Butanes}(g/day) = 215g/bbl \times 3110bbl/day = 670511 \quad \text{(Eq 3.80)}$$

$$VOCTotal(g/day) = 73516 + 2359864 + 670511 = 3103890 \quad \text{(Eq 3.81)}$$

$$VOC(g/bblFT) = \left(\frac{3103890}{1922 + 23943 + 24686}\right) = 61.4 \quad \text{(Eq 3.82)}$$

Particulate Matter Emissions:

PM sources:

1. Fuel gas combustion
2. Power
3. Butanes

$$PM_{FuelCombustion}(g/day) = 1.36g/MMBtu \times 27012MMBtu/day = 36758 \quad \text{(Eq 3.83)}$$

$$PM_{Power}(g/day) = 1.91 \times 54.3MW \times 1000 \times 24hr/day = 2490243 \quad \text{(Eq 3.84)}$$

$$PM_{Butanes}(g/day) = 67/bbl \times 3110bbl/day = 20782 \quad \text{(Eq 3.85)}$$

$$PMTotal(g/day) = 36758 + 2490243 + 20782 = 2547783 \qquad \text{(Eq 3.86)}$$

$$PM\,(g/bblFT) = \left(\frac{2547783}{1922 + 23943 + 24686}\right) = 50.4 \qquad \text{(Eq 3.87)}$$

Table A18: Emissions Inventory for FT Production
(Per bbl of FT Liquid Product)

	Case 1	Case 2	Case 3	Case 4	Case 5*	Case 6*	Case 7	Case 8*
Feedstock	IL #6	IL #6	IL #6	Wyo. Coal	Biomass	Pipeline Gas	Assoc. Gas	Assoc. Gas
Upgrading	Maximum Distillate	Increased Gasoline	Maximum Gaso. & Chem.	Maximum Distillate	Fuels & Power	Maximum Distillate	Minimum Upgrading	Min. Upgrading & Power
CO_2 (g)	534311	526684	507159	575203	706987	119687	210964	92978
CH_4 (g)	58.55	51.14	64.40	87.27	12.97	8.45	4.77	4.79
N_2O (g)	2.16	1.91	2.11	2.85	16.50	1.60	2.02	3.17
SOx (g)	197.64	190.73	193.85	298.04	0	0.06	0	0
NOx (g)	89.08	72.07	98.31	118.82	523.90	51.93	64.15	100.51
CO (g)	15.66	11.73	18.02	19.09	127.23	12.61	15.58	24.41
VOC (g)	61.40	46.19	76.21	91.05	22.45	3.77	2.75	4.31
PM (g)	50.40	48.10	49.53	81.60	11.23	1.14	1.37	2.15

* Values reported only include allocation to fuel products.

C. Emissions Inventory for Power Exported from FT Plants

Design Cases 5, 6 and 8 produce significant excess power for sale. Therefore, it was necessary to allocate emissions between power and fuels in order to make comparisons with the other cases. The procedure used for this allocation has significant effect on the reported emissions per bbl of fuel produced. This uncertainty is compounded by a lack of information on fuel gas generation and consumption for some of the baseline designs. Therefore, caution should be exercised when comparing the emissions from biomass liquefaction to coal liquefaction, or emissions from the various natural gas cases. Example calculations for Design Case 5 will be presented here. Design Cases 6 and 8 follow the same method.

STEP 1: Calculate the energy yields for Design Cases 5, 6 and 8 using equations 3.15 through 3.21. See Table A16 "Resource Consumption and Yields for FT Production" above.

Case 5 energy yields:

Gas/Naphtha (MM Btu/bbl FT) =	1.463
Distillates (MM Btu/bbl FT) =	3.427
Power Sales (MM Btu/bbl FT) =	10.128
Power Sales (kWh/bbl FT) =	1781

Case 5 FT process emissions (Table A18):

CO_2 (g/bbl FT) =	706987
CH4 (g/bbl FT) =	12.97
N2O (g/bbl FT) =	16.50
SOx (g/bbl FT) =	0
NOx (g/bbl FT) =	523.9
CO (g/bbl FT) =	127.23
VOC (g/bbl FT) =	22.45
PM (g/bbl FT) =	11.23

STEP 2: Determine the allocation of power to fuels utilizing the HHVs and LHVs.

$$HHVFuelAllocation = \frac{(Gas/NapEnergy + Distillate\ Energy)}{(Gas/NapEnergy + Distillate\ Energy + PowerSales)} \quad \text{(Eq 3.88)}$$

$$HHVFuelAllocation = \frac{(1.463 + 3.427)}{(1.463 + 3.427 + 10.128)} = .326 \quad \text{(Eq 3.89)}$$

$$LHVFuelAllocation = 1 - HHVFuelAllocation = .674 \quad \text{(Eq 3.90)}$$

STEP 3: Calculate the emissions for exported power from FT plants. Use the component emissions from Table A18 and allocate them to power based on the HHV and LHV percentages.

$$CO_2(g/kWhPower) = \frac{(CO_2(g/bblFT) \times LHVAllocation)}{(PowerSales(kWh) \times HHVFuelAllocation)} \quad \text{(Eq 3.91)}$$

$$CO_2(g/kWhPower) = \frac{(706987g/bblFT \times 0.674)}{(1781kWh/bblFT \times 0.326)} = 822 \quad \text{(Eq 3.92)}$$

$$CH_4(g/kWhPower) = \frac{(12.97 \times 0.674)}{(1781 \times 0.326)} = 0.015 \qquad \text{(Eq 3.93)}$$

$$N_2O(g/kWhPower) = \frac{(16.50 \times 0.674)}{(1781 \times 0.326)} = 0.019 \qquad \text{(Eq 3.94)}$$

$$SO_x(g/kWhPower) = \frac{(0 \times 0.674)}{(1781 \times 0.326)} = 0.000 \qquad \text{(Eq 3.95)}$$

$$NO_x(g/kWhPower) = \frac{(523.9 \times 0.674)}{(1781 \times 0.326)} = 0.609 \qquad \text{(Eq 3.96)}$$

$$CO(g/kWhPower) = \frac{(127.23 \times 0.674)}{(1781 \times 0.326)} = 0.148 \qquad \text{(Eq 3.97)}$$

$$VOC(g/kWhPower) = \frac{(22.45 \times 0.674)}{(1781 \times 0.326)} = 0.026 \qquad \text{(Eq 3.98)}$$

$$PM(g/kWhPower) = \frac{(11.23 \times 0.674)}{(1781 \times 0.326)} = 0.013 \qquad \text{(Eq 3.99)}$$

Table A19: Emissions Inventory for Power Exported from FT Plants
(Per kWh of Electric Power)

	Case 5*	**Case 6***	**Case 8***
Feedstock	Biomass	Pipeline Gas	Assoc. Gas
Upgrading	Fuels & Power	Maximum Distillate	Min. Upgrading & Power
CO_2 (g)	822	243	107
CH_4 (g)	0.015	0.017	0.006
N_2O (g)	0.019	0.003	0.004
SOx (g)	0.000	0.000	0.000
NOx (g)	0.609	0.105	0.116
CO (g)	0.148	0.026	0.028
VOC (g)	0.026	0.008	0.005
PM (g)	0.013	0.002	0.002

*Values reported only include allocation to exported power.

D. Greenhouse Gas Emissions for FT Production

Greenhouse gas emissions for the FT designs have been compiled in Table A21. Emissions of CH_4 and N_2O have been converted to CO_2 equivalents using the global warming potentials (Table A20) for a 100-year time horizon.

Table A20: Global Warming Potentials for Selected Gases
(kg of Gas per kg of CO_2)
[6, pg. 8]

GAS	Lifetime (years)	Direct Effect for Time Horizons of:		
		20 Years	100 Years	500 Years
Carbon Dioxide (CO_2)	Variable	1	1	1
Methane (CH_4)	12 +/- 3	56	21	7
Nitrous Oxide (N_2O)	120	280	310	170

STEP 1: Use the GWPs and component emission data (Section B above) to calculate the GHG emissions from FT production on a per barrel FT basis.

$$CO_{2\,Vented}(g/bblFT) = \frac{22434556368}{(1922+23943+24686)} = 443800 \quad \text{(Eq 3.100)}$$

$$CO_{2\,FuelGasCombustion}(g/bblFT) = \frac{2410548571}{(1922+23943+24686)} = 47685 \quad \text{(Eq 3.101)}$$

$$CO_{2\,FlueGasIncineration}(g/bblFT) = \frac{899966486}{(1922+23943+24686)} = 17803 \quad \text{(Eq 3.102)}$$

$$CO_{2\,Fugitive}(g/bblFT) = \frac{258048044}{(1922+23943+24686)} = 5105 \quad \text{(Eq 3.103)}$$

$$CO_{2\,Ancillary}(g/bblFT) = \frac{926396368+80420775}{(1922+23943+24686)} = 19917 \quad \text{(Eq 3.104)}$$

$$CH_{4\,FuelCombustion}(gCO_2-eq/bblFT) = 21\times\frac{35116}{(1922+23943+24686)} = 15 \quad \text{(Eq 3.105)}$$

$$CH_{4\,Fugitive}(gCO_2-eq/bblFT) = 21\times\frac{349081}{(1922+23943+24686)} = 145 \quad \text{(Eq 3.106)}$$

$$CH_{4\,Ancillary}(gCO_2-eq/bblFT) = 21\times\frac{2289459+286220}{(1922+23943+24686)} = 1070 \quad \text{(Eq 3.107)}$$

$$N_2O_{Combustion}(gCO_2-eq/bblFT) = 310\times\frac{54024}{(1922+23943+24686)} = 331 \quad \text{(Eq 3.108)}$$

$$N_2O_{Ancillary}(gCO_2-eq/bblFT) = 310\times\frac{54890+130}{(1922+23943+24686)} = 337 \quad \text{(Eq 3.109)}$$

$TOTAL\ (gCO_2-eq/bblFT) = 536209$ *Sum of Eqs 4.100 to 4.109.

Table A21: GHG Emissions from FT Production
(Per bbl of FT Liquid Product)

	Case 1	Case 2	Case 3	Case 4	Case 5*	Case 6*	Case 7	Case 8*
Feedstock	IL #6	IL #6	IL #6	Wyo. Coal	Biomass	Pipeline Gas	Assoc. Gas	Assoc. Gas
Upgrading	Maximum Distillate	Increased Gasoline	Maximum Gaso. & Chem.	Maximum Distillate	Fuels & Power	Maximum Distillate	Minimum Upgrading	Min. Upgrading & Power
CO_2 – vented gas (g)	443800	441652	400060	440972	0	64289	94294	0
CO_2 – combustion flue gas (g)	47685	44538	65931	92081	706987	54565	115726	92978
CO_2 – incineration flue gas (g)	17803	17739	16037	5493	0	0	0	0
CO_2 – fugitive emissions (g)	5105	5081	4601	5126	0	643	943	0
CO_2 – ancillary sources (g)	19917	17675	20530	31531	0	191	0	0
CH_4 – combustion flue gas (g CO_2-eq)	15	12	14	15	225	22	28	43
CH_4 – fugitive & flaring (g CO_2-eq)	145	145	145	145	47	141	73	57
CH_4 – ancillary sources (g CO_2-eq)	1070	917	1193	1673	0	14	0	0
N_2O – combustion flue gas (g CO_2-eq)	331	266	328	334	5115	497	626	981
N_2O – ancillary (g CO_2-eq)	337	325	327	551	0	0	0	0
Total (g CO_2-eq)	536209	528350	509166	577921	712374	120361	211690	94060

* Values reported only include allocation to fuel production

SECTION 4

RESOURCE EXTRACTION

4. RESOURCE EXTRACTION

A. Utility consumption for coal production

STEP 1: Data Collection

Table A22: Surface Coal Mining Utility and Chemical Requirements
[16]

		Units		Units
Electricity	14,300	MWh/year/MM tonne	44,311	Btu/ton
Fuel & Oil	269	m^3/year/MM tonne	0.0645	Gal/ton
Ammonium Nitrate	2070	Mg/year/MM tonne	4.14	Lb/ton

Table A23: Underground Coal Mining Utility and Chemical Requirements
[16]

		Units		Units
Electricity	12,755	MWh/year/MM tonne	39,523	Btu/ton
Raw Water	84,482	m^3/year/MM tonne	20.3	Gal/ton
Limestone	16,263	Mg/year/MM tonne	32.5	Lb/ton

Table A24: Coal Cleaning Utility and Landfilling Requirements (Base Case)
[16]

		Units
Electricity	0.79	MJ/Mg of MAF raw coal
Raw Water	0.17	m^3/Mg of raw coal
Refuse	0.35	Dry Mg/Mg of MAF raw coal

STEP 2: Calculate the resource consumption for coal production using Tables A22, A23 and A24.

*Note: MF = Moisture Free
MAF = Moisture & Ash Free

*Illinois #6 underground coal contains 11.5% ash and Wyoming coal contains 8.7% ash. See Ultimate analysis Table A36 at end of Appendix A.

Refuse:
Refuse includes ash forming material, rocks and very fine coal that are removed during coal cleaning. Ultimate analysis coal data is moisture free, therefore subtract % ash from 1.0 to obtain moisture free & ash free coal basis. Equation 4.1 is based on percentages, therefore any units can be used such as lb refuse/lb MF coal produced or ton refuse/ton MF coal produced.

$$refuse\,(Ton\,/\,TonMFcoalp\;\;roduced\;) = \left(\frac{0.35\,Mgrefuse}{MgMAFrawco\;\;al}\right)\times\left(\frac{MAFrawcoal}{MFrawcoal}\right) \quad \text{(Eq 4.1)}$$

$$refuse\,(Ton\,/\,TonMFcoalp\;\;roduced\;) = \left(\frac{0.35\,Mgrefuse}{MgMAFrawco\;\;al}\right)\times\left(\frac{(1-0.115)\,MAFrawcoal}{1.0\,MFrawcoal}\right) = 0.3098$$

Water Make-Up:

Water Make-up for the Illinois #6 case includes water for underground mining procedures and above ground coal cleaning processes.

Underground water: The underground water consumption is greater than 20.25 gallons/ton coal because refuse (ash and rocks) is included in the total coal mined until it reaches the cleaning/separation process. Therefore, the water consumption is based on the total bulk material removed underground.

$$H_2O(gal\,/\,Ton) = \left(\frac{20.25\,gal}{TonMFCoalp\;roduced}\right)\times\left(\frac{1-0.3098\,Tonrefuse}{TonMFCoalp\;roduced}\right) = 26.52 \quad \text{(Eq 4.2)}$$

Coal cleaning water:

$$H_2O(gal\,/\,Ton) = \left(\frac{0.17\,m^3}{1MMtonMAFRawcoal}\right)\times 264\,gal\,/\,m^3 \times 907185\,g\,/\,Ton \times \left(\frac{1-0.115TonMAFRawcoal}{TonMFCoalproduced}\right) = 36.1 \quad \text{(Eq 4.3)}$$

Water required per ton of coal produced:
H_2O Total (gal/ton) = 62.62

Limestone:

$$Limestone(ton\,/\,tonMFcoalproduced) = \left(\frac{32.54\,lbLimestone}{TonMFCoalproduced}\right)\times\left(\frac{1+0.3098}{TonMFCoalproduced}\right) \quad \text{(Eq 4.4)}$$

Limestone Total (ton/toncoal) = 42.62

Electricity:

Electricity for the Illinois #6 case includes electricity for the underground coal extraction process and surface coal cleaning process (Jig washing).

Underground Electricity:

$$Electricity(kWh\,/\,ton) = \left(\frac{12755e6Wh}{TonneMFCoa\,lproduced}\right)\times(1/1.102)\times\left(\frac{1+0.3098Tonrefuse}{TonMFCoalp\,roduced}\right)\times\left(\frac{1}{1000}\right) = 15.35 \quad \text{(Eq 4.5)}$$

Coal Cleaning Electricity:

$$Electricity(kWh\,/\,ton) = \left(\frac{0.79e6J}{1e6MAFrawcoal}\right)\times(1hr\,/\,3600s)\times 907185\,g\,/\,Ton\times\left(\frac{1-0.115TonMAFrawc\,oal}{TonMFCoalp\,roduced}\right)\times\left(\frac{1kW}{1000W}\right) = 0.176 \quad \text{(Eq 4.6)}$$

Electricity Total (kWh/tonCoal) = 15.4

Table A25: Resource Consumption for Coal Production
(Per ton of MF Coal Produced)

	Illinois #6 Underground Mine	Illinois #6 Surface Mine	Wyoming Surface Mine
Electricity (kWh)	15.4	58.3	17.4
Distillate Fuel (gal)		0.084	0.089
Water Make-Up (gal)	62.62	46.06	44.65
Limestone (lb)	42.6		
Ammonium Nitrate (lb)		5.42	5.46
Refuse (ton)	-0.310	-0.310	-0.320

B. Coal Bed Methane

Coal bed methane is produced from the underground mining activities (extraction of coal to the surface) and underground post-mining activities (treatment of underground coal). The underground post-mining activities are not to be confused with surface strip mining. The post-mining activities include the handling, cleaning, etc. of the coal once it is brought to the surface. The EPA gives the post-mining methane emission factor (standard cubic feet of methane emitted per ton coal produced) directly, but the underground mining factor must be calculated from other EPA data.

Total Illinois Underground coal production (tons): 64,728,000 [18]
Total Illinois Underground methane (scf): 8,571e6 [18]
Illinois Underground post mining emission factor (scf/ton): 12.7* [18]
*Post mining emission factor given directly by the EPA [18]

Calculate the underground mining emission factor.

$$CH_4Underground(scf\ /Tons) = \left(\frac{8{,}571e6scfCH_4}{64{,}728e3TonsCoalProduced}\right) = 132.4 \qquad \text{(Eq 4.7)}$$

$$CH_4UndergroundTotal(scf/Ton)=CH_4Underground + CH_4\ UndergroundPost \qquad \text{(Eq 4.8)}$$

CH_4 Total (scf/ton) = 145 or (2779 g/ton)

Table A26: Coalbed Methane Emissions
(Per ton of MF Coal Produced)
[18]

	Illinois #6 Underground Mine	Illinois #6 Surface Mine	Wyoming Surface Mine
CH_4 (scf)	145	90	7.4
CH_4 (g)	2779	1725	142

C. Emissions inventory for coal production

Emissions sources included in the inventory are coalbed methane release, emissions from electricity, and emissions from diesel fuel. No ancillary diesel fuel is used for Design Case 1, Illinois #6 underground mining.

STEP 1: Calculate the emissions for each component

CO_2 emissions:

Source: Electricity (No diesel fuel is used in underground mining)

$$CO_2Power\,(g\,/\,TonMFCoalproduced) = \left(\frac{15.35kWhUsed}{TonMFCoalproduced}\right) \times \left(\frac{710.10gCO_2}{kWhproduced}\right) = 10904 \quad \text{(Eq 4.9)}$$

CH_4 emissions:

Source: Electricity and coalbed methane.

$$CH_4Power\,(g\,/\,TonMFCoalproduced) = \left(\frac{15.35kWhUsed}{TonMFCoalproduced}\right) \times \left(\frac{1.756gCH_4}{kWhproduced}\right) = 26.9 \quad \text{(Eq 4.10)}$$

CH_4 Coalbed Methane (g/tonMFCoalproduced) = 2779*
*Table A26

Methane Total (g/tonMFCoalproduced) = 2806

N_2O emissions:

Source: Electricity

$$N_2OPower\,(g\,/\,TonMFCoalproduced) = \left(\frac{15.35kWhUsed}{TonMFCoalproduced}\right) \times \left(\frac{0.0421gN_2O}{kWhproduced}\right) = 0.646 \quad \text{(Eq 4.11)}$$

SOx emissions:

Source: Electricity

$$SOxPower\,(g\,/\,TonMFCoalproduced) = \left(\frac{15.35kWhUsed}{TonMFCoalproduced}\right) \times \left(\frac{6.92gSOx}{kWhproduced}\right) = 106.2 \quad \text{(Eq 4.12)}$$

NOx emissions:

Source: Electricity

$$NOxPower(g\,/\,TonMFCoalproduced) = \left(\frac{15.35kWhUsed}{TonMFCoalproduced}\right) \times \left(\frac{1.81gNOx}{kWhproduced}\right) = 27.8 \quad \text{(Eq 4.13)}$$

CO emissions:

Source: Electricity

$$COPower(g\,/\,TonMFCoalproduced) = \left(\frac{15.35kWhUsed}{TonMFCoalproduced}\right) \times \left(\frac{0.205gCO}{kWhproduced}\right) = 3.15 \quad \text{(Eq 4.14)}$$

<u>VOC emissions</u>:

$$VOCPower(g/TonMFCoalproduced) = \left(\frac{15.35kWhUsed}{TonMFCoalPproduced}\right) \times \left(\frac{1.81gVOC}{kWhproduced}\right) = 27.8 \quad \text{(Eq 4.15)}$$

<u>PM emissions</u>:

$$PMPower(g/TonMFCoalproduced) = \left(\frac{15.35kWhUsed}{TonMFCoalproduced}\right) \times \left(\frac{1.91gPM}{kWhproduced}\right) = 29.3 \quad \text{(Eq 4.16)}$$

Table A27: Emissions Inventory for Coal Production (Per ton of MF Coal Produced)

	Illinois #6 Underground Mine	Illinois #6 Surface Mine	Wyoming Surface Mine
CO_2 (g)	10904	41425	12358
CH_4 (g)	2806	1826	172
N_2O (g)	0.65	2.5	0.73
SOx (g)	106.2	403	120.2
NOx (g)	27.8	105.2	31.6
CO (g)	3.2	12.1	3.7
VOC (g)	27.8	105.5	31.4
PM (g)	29.3	111.3	33.2

STEP 2: Convert the emissions inventory data (Table A27) for coal production into CO_2 equivalents using the global warming potential factors in Table A20 for methane and nitrous oxide.

$$CH_4(gCO_2 - eq/TonMFCoalproduced) = \left(\frac{2962gCH_4}{TonMFCoalproduced}\right) \times \left(\frac{21gCO2 - eq}{gCH_4}\right) = 62202 \quad \text{(Eq 4.17)}$$

$$N_2O(gCO_2 - eq/TonMFCoalproduced) = \left(\frac{0.65gN_2O}{TonMFCoalproduced}\right) \times \left(\frac{310gCO2 - eq}{gN_2O}\right) = 200 \quad \text{(Eq 4.18)}$$

Table A28: Greenhouse Gas Emissions from Coal Production (Per ton of MF Coal Produced)

	Illinois #6 Underground Mine	Illinois #6 Surface Mine	Wyoming Surface Mine
CO_2 (g)	10904	12272	12358
CH_4 (g CO_2-eq)	58928	36850	3618
N_2O (g CO_2-eq)	200	225	227
Total	70030	49348	16203

SECTION 5

TRANSPORTATION
AND
DISTRIBUTION

5. TRANSPORTATION AND DISTRIBUTION

Design Case 1 of Scenario 1 coal is mined in southern Illinois and the FT plant is next to coal mine. The FT fuels produced are shipped by pipeline to the Chicago area (~200 miles) and distributed to a local re-fueling station by tank truck (~60 miles). The pipeline uses electricity and the tank truck uses distillate fuel. Emissions for both types of FT transportation (pipeline and tank truck) were calculated in the Section 2 "Ancillary Emissions".

A. Emissions Inventory for Transportation

STEP 1: Data collection

FT density (lb/gal):	6.163 lb/gal
Pipeline (miles):	200 miles
Tank truck (miles):	60 miles

Table A29: Energy Consumption for Different Modes of Transportation (Btu/ton-mile)
[20, pg. E-5]

Truck	Tanker	Barge	Train	Pipeline
1900	408	197	516	120

Table A30: Upstream and Combustion Emission Factors for Distillate Fuel, Residual Fuel and Electricity. (lb/MM Btu fuel consumed)
[Calculated in Ancillary Section]

	CO_2	CH_4	N_2O	SOx	NOx	CO	PM	VOC
Distillate Fuel	177	0.009	0.006	0.871	0.767	1.027	0.147	0.007
Residual Fuel	191	0.254	0.004	2.396	0.627	0.109	0.147	0.094
Electricity	149	0.368	0.008	1.45	0.55	0.176	0.40	0.004

STEP 2: Calculate the emissions per gallon of FT fuel transported (Pipeline to Chicago and then Chicago to distribution).

$$Emissions(g / galFTFuel) = (EnergyConsumption)\times(Distance)\times(Density)\times(Emissions)\times(Conv.Fact) \quad \text{(Eq 5.1)}$$

<u>CO_2 transportation example</u>:

Truck:

$$TruckCO_2(g / galFT) = (1900)\times(60)\times(1/2000)\times(6.163)\times(177.4/1e6)\times(454) = 28.29 \quad \text{(Eq 5.2)}$$

Pipeline:

$$PipelineCO_2\,(g/galFT) = (120)\times(200)\times(1/2000)\times(6.163)\times(148.9/1e6)\times(454) = 5.00 \quad \text{(Eq 5.3)}$$

Total CO_2 (g/galFT) = 33.3

Methane Transportation Example:

Truck:

$$TruckCH_4\,(g/galFT) = (1900)\times(60)\times(6.163)\times(0.009471/1e6)\times(454) = 0.00151 \quad \text{(Eq 5.4)}$$

Pipeline:

$$PipelineCH_4\,(g/galFT) = (120)\times(200)\times(1/2000)\times(6.163)\times(0.3684/1e6)\times(454) = 0.01237 \quad \text{(Eq 5.5)}$$

Total Methane (g/gal FT) = 0.01388

Calculate the remaining component emissions using equation 5.1.

Table A31: Emissions Inventory for Transportation Scenario 1
(Per gal of FT Fuel Transported)

Transportation Mode	**Truck**	**Tanker**	**Pipeline**	**Total**
Southern Illinois to Chicago	DFO	RFO	Electricity	
Miles	60	na	200	260
CO_2 (g)	28.29	na	5.00	33.3
CH_4 (g)	0.0015	na	0.0124	0.0139
N_2O (g)	0.0009	na	0.0003	0.0012
SOx (g)	0.1389	na	0.0487	0.1876
NOx (g)	0.1223	na	0.0185	0.1408
CO (g)	0.1638	na	0.0059	0.167
PM (g)	0.0235	na	0.0134	0.0369
VOCs (g)	0.0011	na	0.00013	0.0012

B. Greenhouse Gas Emissions from Transportation

Multiply the global warming potential factors (Table A20) by the transportation emissions inventory (Table A31). All scenarios presented in Table 32.

Table A32: Greenhouse Gas Emissions from Transportation
(Per gal of FT Fuel Transported)

	Truck	**Tanker**	**Pipeline**	**Total**
Scenario 1, 3 & 4 (g CO_2-eq/gal FT)	28.61	na	5.34	33.96
Scenario 2 (g CO_2-eq/gal FT)	28.61	na	26.74	55.35
Scenario 5 (g CO_2-eq/gal FT)	28.61	225.57	32.08	286.26
Scenario 6 (g CO_2-eq/gal FT)	28.61	465.80	21.39	516.80

SECTION 6

FULL FISCHER TROPSCH FUEL LIFE-CYCLE INVENTORY

6. FULL FT-FUEL LIFE –CYCLE INVENTORY

Six baseline scenarios were identified for consideration in this study. They involve the evaluation of different options for the resource extraction, conversion, and transportation/distribution steps in the FT fuel chain. Detailed calculations of Scenario 1 are presented here.

Scenario 1: Production of FT fuels from bituminous Illinois No. 6 coal at a mine-mouth location in southern Illinois. The mine is an underground longwall mine. The design of the FT conversion plant is based on Design Case 1 described in Section 3 of the main report. Upgrading includes a full slate of refinery processes for upgrading FT naphtha. Hydrocracking is used to convert the FT wax into additional naphtha and distillate. The liquid fuel products are shipped by pipeline to a terminal in the Chicago area and distributed by tank truck to re-fueling stations in the immediate area.

A. Emissions Inventory for Full FT Fuel Chain

Individual inventories for the FT conversion (Section 3), resource extraction (Section 4), and transportation/distribution (Section 5) steps of the FT fuel chain are compiled here. They are the full inventories up through the point of sale of the FT fuel, and are based on the entire FT liquid-fuel product slate. That is, the individual products: LPG, gasoline/naphtha, and distillate fuel have not been broken out separately. Re-fueling and end-use combustion are not included. GHG emission allocation to diesel fuel only and combustion emissions are considered in the next case study. All values for Scenario 1 were calculated in the above sections. An example using carbon dioxide is shown below.

$$CO_2(g / galFTFuel) = CO_2Extraction + CO_2Converstion + CO_2Transportation \qquad \text{(Eq 6.1)}$$

STEP 1: Use data in Tables A16 and A27 to determine the airborne emissions from coal extraction per gallon of FT produced.

CO_2 example:

Data: Coal consumption (ton/bblFT) = 0.36745 [Table A16]

CO_2 (g/MF ton coal) = 10904 [Table A27]

$$CO_2Extraction(gCO_2 / galFT) = \left(\frac{10904gCO_2}{toncoal}\right)\times\left(\frac{0.36745toncoal}{bbl}\right)\times\left(\frac{bbl}{42gal}\right) = 95.4 \qquad \text{(Eq 6.2)}$$

Methane example:

Data: Coal consumption (ton/bblFT) = 0.36745 [Table A14]

CH_4 (g/MF ton coal) = 2806 [Table A27]

$$CH_4Extraction(gCO_2 / galFT) = \left(\frac{2806gCO_2}{toncoal}\right)\times\left(\frac{0.36745toncoal}{bbl}\right)\times\left(\frac{bbl}{42gal}\right) = 24.5 \qquad \text{(Eq 6.3)}$$

STEP 2: Calculate the Full FT Fuel Chain Emissions.

CO_2 example:

CO_2 FT Conversion (g/Bbl FT Product) = 534311 [Table A18]

CO_2 Transportation (g/gal FT Product) = 33.3 [Table A31]

Total CO_2 emissions for FT fuels at point of sale (use Eq 7.1):

$$CO_2(g / galFTFuel) = 95.4 + \left(\frac{534311}{42}\right) + 33.3 = 12857 \quad \text{(Eq 6.4)}$$

Methane example:

CH_4 FT Conversion (g/Bbl FT Product) = 58.55 [Table A18]

CH_4 Transportation (g/gal FT Product) = 0.0139 [Table A31]

Total CH_4 emissions for FT fuels at point of sale:

$$CH_4(g / galFTFuel) = 24.5 + \left(\frac{58.55}{42}\right) + 0.0139 = 26.0 \quad \text{(Eq 6.5)}$$

Calculate and tabulate the remaining emissions inventory for FT fuels at point of sale using data in Tables A16, A18, A27, A31 and equations 6.1 and 6.2.

Table A33: Emissions Inventory for FT Fuels at Point of Sale (Per gal of FT Fuel Supplied)

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
CO_2 (g)	12857	13865	-6564	4236	6385	6607
CH_4 (g)	26.0	3.76	0.45	14.9	6.07	6.36
N_2O (g)	0.059	0.08	0.65	0.08	0.09	0.096
SOx (g)	5.82	8.61	0.19	0.23	3.22	6.03
NOx (g)	2.50	3.34	17.8	11.7	10.4	10.8
CO (g)	0.57	0.68	5.33	2.98	2.46	2.49
VOC (g)	1.73	2.47	2.66	16.5	13.2	13.2
PM (g)	1.49	2.35	0.30	0.06	0.30	0.45

B. Case Study—Substitution of FT Diesel Fuel in SUVs

The results from the FT LCI were used to evaluate the application of FT diesel as a substitute for petroleum fuels in Sport Utility Vehicles (SUVs) and the greenhouse gas emissions that would result. FT diesel has been demonstrated to have emissions that are much lower than those from petroleum diesel for the same engine. There is however a penalty to fuel economy when using FT diesel due to its lower energy density per gallon to petroleum-derived diesel. FT diesel fuel economy in an SUV has been estimated to be about 24.4 mpg. The full life-cycle GHG emissions for FT diesel is presented here is based on Scenario 1, Illinois #6 coal.

Results include airborne emissions from extraction/production, conversion/refining, transportation/distribution and end use combustion. Results are given in g CO_2-equivalent per mile in SUV.

STEP 1: Determine the FT diesel allocation by using data in Table A14. Divide FT diesel produced by total FT liquid produced.

$$DieselAllocation = \left(\frac{24686}{24686+1922+23943}\right) = 0.49 \qquad \text{(Eq 6.6)}$$

STEP 2: Calculate airborne emissions per SUV mile from coal extraction.

Data: Coal consumption (ton/bblFT) = 0.36745 [Table A16]
GHG emissions from coal production (gCO_2-eq/ton) = 70,032 [Table A28]

$$Extraction\,(gCO_2eq\,/\,SUVmile) = \left(\frac{.51}{.49}\right)\times\left(\frac{70032\,gCO_2eq}{toncoal}\right)\times\left(\frac{0.36745\,toncoal}{bblFT}\right)\times\left(\frac{bblFT}{42\,gal}\right)\times\left(\frac{galFT}{24.4SUVmiles}\right) = 26.1 \qquad \text{(Eq 6.7)}$$

STEP 3: Calculate airborne emissions per SUV mile for conversion/refining.

Data: GHG emissions from FT production (gCO_2-eq/bblFT) = 536,209 [Table A21]

$$Conversion\,(gCO_2eq\,/\,SUVmile) = \left(\frac{.51}{.49}\right)\times\left(\frac{536209\,gCO_2eq}{bblFT}\right)\times\left(\frac{bbl}{42\,gal}\right)\times\left(\frac{gal}{24.4mile}\right) = 543 \qquad \text{(Eq 6.8)}$$

STEP 4: Calculate airborne emissions per SUV mile for transportation/distribution.

Data: GHG emissions from Trans/Dist (gCO_2-eq/galFT) = 33.96 [Table A32]

$$Transporta\,tion\,(gCO_2eq\,/\,SUVmile) = \left(\frac{.51}{.49}\right)\times\left(\frac{33.96\,gCO_2eq}{galFT}\right)\times\left(\frac{gal}{24.4mile}\right) = 1.45 \qquad \text{(Eq 6.9)}$$

STEP 5: Calculate airborne emissions for end use combustion of FT diesel fuel.

Data: Combustion (gCO_2/gal FT fuel) = 9011.05 [Table A36]

$$Combustion\,(gCO_2eq\,/\,SUVmile) = \left(\frac{9011.05\,gCO_2}{galFT}\right)\times\left(\frac{gal}{24.4mile}\right) = 368 \qquad \text{(Eq 6.10)}$$

STEP 6: Aggregate the Total Fuel Chain GHG Emissions.

$$Total(gCO_2eq\,/\,SUVmile) = 26.0 + 543 + 1.45 + 368 = 939 \qquad \text{(Eq 6.11)}$$

Table A34: Full Life-Cycle GHG Emissions for FT Diesel
(g CO_2-eq/SUV mile)

Scenario/ FT Plant Feedstock	Extraction/ Production	Conversion/ Refining	Transportation/ Distribution	End Use Combustion	Total
1) IL #6 Coal	26	543	1.4	368	939
2) Wyoming Coal	7	585	2.3	368	962
3) Plantation Biomass	-969	703	1.4	368	104
4) Pipeline Natural Gas	71	121	1.4	368	562
5) Venezuelan Assoc. Gas	51	213	11	368	643
6) ANS Associated Gas	51	213	21	368	652

C. Sensitivity Cases for Substitution of FT Diesel Fuel in SUVs

To help identify possible GHG reduction strategies for FT fuels production, a number of sensitivity cases were considered for the scenarios described above. These included the following:

- Advanced diesel engines
- Coalbed methane capture
- Sequestration of vented CO_2 from conversion process
- Sequestration of CO_2 from conversion process and combustion
- Co-production of fuels and power
- Co-processing of coal and biomass
- Co-processing of coal and coalbed methane

Re-calculate the Full Life-Cycle GHG emissions based on SUV miles as shown in the previous section but with taking into account the reduction scenarios.

1a). <u>Illinois #6 coal baseline</u>

Total fuel chain emissions from Table A34 above is 939 g CO_2-eq/mile in SUV.

1b). <u>Sequestration of FT process CO_2</u>

This involves re-calculating the airborne emissions for the FT conversion process, minus the vented CO_2 emissions.

Data: Total FT process CO_2 (gCO_2-eq/bblFT) = 536209 [Table A21]
Vented CO_2 (gCO_2-eq/bblFT) = 443800 [Table A21]
*The remaining extraction, transportation and combustion emissions remain unchanged.

Re-calculated FT conversion emissions:

$$Conversion\ (gCO_2eq/SUVmile) = \left(\frac{.51}{.49}\right)\times\left(\frac{536209-443800}{42\times 24.4}\right) = 93.9 \quad \text{(Eq 6.12)}$$

Re-calculated existing diesel engine fuel chain emissions:

$$Total\ (gCO_2eq/SUVmile) = 26+93.9+1.4+368 = 490 \quad \text{(Compared to 939!)} \quad \text{(Eq 6.13)}$$

Reduction amount = 449 gCO_2-eq/SUVmile or 48%.

*Assume advanced diesel engine has 13% lower emissions than existing diesel engine.

$$AdvancedDiesel(gCO_2eq / SUVmile) = 490 \times (1 - .13) = 426 \quad \text{(Eq 6.14)}$$

1c). Sequestration of Vented and Combusted GHG Emissions

This involves re-calculating the airborne emissions for the FT conversion process, minus the emissions from: vented CO_2, CO_2 combustion flue gas, CH_4 combustion flue gas, and N_2O combustion flue gas.

Data:
- Total FT process CO_2 (gCO_2-eq/bblFT) = 536209 [Table A21]
- Vented CO_2 (gCO_2-eq/bblFT) = 443800 [Table A21]
- CO_2 combustion (gCO_2-eq/bblFT) = 47685 [Table A21]
- CO_2 incineration (gCO_2-eq/bblFT) = 17803 [Table A21]
- CH_4 combustion (gCO_2-eq/bblFT) = 15 [Table A21]
- N_2O combustion (gCO_2-eq/bblFT) = 331 [Table A21]

*The remaining extraction, transportation and end-use combustion emissions remain unchanged.

Re-calculated FT conversion emissions:

$$Conversion\ (gCO_2eq / SUVmile) = \left(\frac{.51}{.49}\right) \times \left(\frac{536809 - 443800 - 47685 - 17803 - 15 - 331}{42 \times 24.4}\right) = 27 \quad \text{(Eq 6.15)}$$

Re-calculated existing diesel engine fuel chain emissions:

$$Total(gCO_2eq / SUVmile) = 26 + 27 + 1.4 + 368 = 423 \quad \text{(Eq 6.16)}$$

Reduction amount = 516 gCO_2-eq/SUVmile or 55%.

*Assume advanced diesel engine has 13% lower emissions than existing diesel engine.

$$AdvancedDiesel(gCO_2eq / SUVmile) = 423 \times (1 - .13) = 368 \quad \text{(Eq 6.17)}$$

1d). Co-production of fuels and power

Plant efficiency improvements due to this "once-through" conversion approach results in a 56% reduction in emissions from FT production (conversion). The remaining extraction, transportation and combustion emissions remain unchanged from the baseline.

Re-calculated FT conversion emissions:

$$Conversion(gCO_2eq / SUVmile) = 543 \times (1 - .56) = 239 \quad \text{(Eq 6.18)}$$

Re-calculated existing diesel engine fuel chain emissions:

$$Total(gCO_2eq / SUVmile) = 26 + 239 + 1.4 + 368 = 635 \quad \text{(Eq 6.19)}$$

Reduction amount = 304 gCO_2-eq/SUVmile or 32%.

*Assume advanced diesel engine has 13% lower emissions than existing diesel engine.

$$AdvancedDiesel(gCO_2eq / SUVmile) = 635 \times (1 - .13) = 552 \quad \text{(Eq 6.20)}$$

1e). Co-processing of biomass

Co-processing of other feedstocks with coal may also be a viable approach to reducing GHG emissions. Here are results of co-feeding 20% of the feedstock from biomass (based on heating value).

Data: Coal LHV = 11945 Btu/lb or 23.89 MM Btu/ton [7]
Biomass LHV = 1124 Btu/lb or 15.44 MM Btu/ton [7]
Basis (MM Btu) = 100 (80 MM to coal, 20 MM to bio)
Coal (ton/bbl FT liquid product) = 0.3675 [Table A16]
Biomass (ton/bbl FT liquid product) = 0.621 [Table A16]

With the given data, it was determined that 3.3486 tons of coal and 1.2953 tons of biomass are required for each 100 MM Btu feedstock to the gasifier.

$$CoalConv\ (galFT\ /80\,MMBtu) = \left(\frac{3.3486\,toncoal}{80\,MMBtu}\right)\times\left(\frac{bblFT}{0.36745\,toncoal}\right)\times\left(\frac{42\,gal}{bblFT}\right) = 382.7 \quad \text{(Eq 6.21)}$$

$$BioConv\ (galFT\ /20\,MMBtu) = \left(\frac{1.2953\,tonbiomass}{20\,MMBtu}\right)\times\left(\frac{bblFT}{0.621\,tonbiomass}\right)\times\left(\frac{42\,gal}{bblFT}\right) = 87.6 \quad \text{(Eq 6.22)}$$

$$\%\ fromBio = \left(\frac{87.6}{382.7+87.6}\right)\times 100 = 18.6 \quad \text{(Eq 6.23)}$$

% From Coal = 81.4

Use the Scenario 1 (coal) baseline and Scenario 3 (biomass) data in Table A34 and the allocated percentages for biomass and coal to re-calculate the full life-cycle GHG emissions for the entire fuel chain; extraction, conversion, transportation and end use combustion.

Re-calculated biomass and coal extraction emissions:

$$Extraction\ (gCO_2-eq\ /\ SUVmile) = (26\times.814)+(-969\times 0.186) = -159 \quad \text{(Eq 6.24)}$$

Re-calculated biomass and coal conversion emissions:

$$Conversion\ (gCO_2-eq\ /\ SUVmile) = (543\times.814)+(703\times 0.186) = 572 \quad \text{(Eq 6.25)}$$

Re-calculated biomass and coal transportation emissions:

$$Transportation(gCO_2-eq\ /\ SUVmile) = (1.388\times.814)+(1.456\times 0.186) = 1.4 \quad \text{(Eq 6.26)}$$

*Assume no change in end-use combustion.

Re-calculated existing diesel engine fuel chain emissions:

$$Total\ (gCO_2eq\ /\ SUVmile) = -159 + 572 + 1.4 + 368 = 783 \quad \text{(Eq 6.27)}$$

Reduction amount = 155 gCO_2-eq/SUVmile or 17%.

*Assume advanced diesel engine has 13% lower emissions than existing diesel engine.

$$AdvancedDiesel(gCO_2eq\ /\ SUVmile) = 783\times(1-.13) = 682 \quad \text{(Eq 6.28)}$$

1f). Coalbed methane capture

This involves re-calculating the airborne emissions for the coal extraction process, minus the coalbed methane. The remaining conversion, transportation and combustion values remain unchanged from the baseline (1a).

Data: Coalbed methane (gCH_4/toncoal) = 2779 [Table A26]
Coal consumption (ton/bblFT) = 0.36745 [Table A16]

Re-calculate CO_2 equivalent emissions from coalbed methane:

$$CH_4(gCO_2eq/bblFT) = \left(\frac{2779gCH_4}{toncoal}\right)\times\left(\frac{21gCO_2-eq}{gCH_4}\right)\times\left(\frac{0.36745toncoal}{bblFT}\right) = 21{,}444 \quad \text{(Eq 6.29)}$$

Re-calculate total underground mining CO_2 equivalent emissions per bbl FT:

$$Total(gCO_2eq/bblFT) = \left(\frac{70032gCO_2eq}{toncoal}\right)\times\left(\frac{0.36745toncoal}{bblFT}\right) = 25{,}733 \quad \text{(Eq 6.30)}$$

Re-calculate the extraction emissions (minus the coalbed methane):

$$Extraction(gCO_2eq/bblFT) = \left(\frac{.51}{.49}\right)\times\left(\frac{25{,}733-21{,}444gCO_2eq}{bblFT}\right)\times\left(\frac{bbl}{42gal}\right)\times\left(\frac{gal}{24.4mile}\right) = 4.3 \quad \text{(Eq 6.31)}$$

Re-calculate existing diesel engine fuel chain emissions:

$$Total\ (gCO_2eq\ /\ SUVmile\ ) = 4.3 + 543 + 1.4 + 368 = 917 \quad \text{(Eq 6.32)}$$

Reduction amount = 22 gCO_2-eq/SUVmile or 2.3%.

*Assume advanced diesel engine has 13% lower emissions than existing diesel engine.

$$AdvancedDiesel(gCO_2eq/SUVmile) = 917\times(1-0.13) = 798 \quad \text{(Eq 6.33)}$$

1g). Co-processing of coalbed methane

Co-processing of coalbed methane involves re-calculating the airborne emissions for the full fuel chain by producing 50 percent of the FT product from methane and 50 percent of the FT product form coal. Extraction and conversion are different than the baseline case but transportation and combustion are assumed to be the same as the baseline since the FT products from co-processing are assumed to be similar to the FT products from the baseline scenario.

Scenario 1f emissions are used for the coal feedstock portion (50 percent) and Scenario 4a (modified pipeline gas) is used for the coalbed methane feedstock portion. A straight 50 percent of Scenario 1f emissions is allocated to the coal portion here for extraction and conversion. Fifty percent of Scenario 4a (pipeline gas) emissions are allocated to the coalbed methane portion here for conversion, but not for extraction. A pipeline gas transmission credit is subtracted from the extraction step since the FT plant is near the coal mine, and therefore, no gas transportation is required. This transmission credit is estimated to be 20gCO_2eq/SUVmile. A second credit from gas processing subtracted from the extraction step of the pipeline gas since the coalbed methane is not processed. The gas processing credit is estimated to be approximately 49 gCO_2eq/SUVmile. Note that these are only ESTIMATES!

Re-calculate the extraction emissions:

$$Extraction(gCO_2eq/SUVmile) = (0.5\times4.3)+(0.5\times(71-20-49)) = 3.2 \quad \text{(Eq 6.34)}$$

Re-calculated biomass and coal conversion emissions:

$$Conversion(gCO_2eq/SUVmile) = (0.5 \times 543) + (0.5 \times 121) = 332 \quad \text{(Eq 6.35)}$$

Re-calculate existing diesel engine fuel chain emissions:

$$Total(gCO_2eq/SUVmile) = 3.2 + 332 + 1.4 + 368 = 705 \quad \text{(Eq 6.36)}$$

Reduction amount = 234 gCO_2-eq/SUVmile or 25%.

*Assume advanced diesel engine has 13% lower emissions than existing diesel engine.

$$AdvancedDiesel(gCO_2eq/SUVmile) = 705 \times (1 - 0.13) = 613 \quad \text{(Eq 6.37)}$$

Table A35: Life-Cycle Sensitivity Analysis for FT Diesel
(g CO_2-eq/SUV mile)

Scenario/ FT Feedstock Source	GHG Emissions Reduction		Total Fuel Chain	
			existing diesel engine	advanced diesel engine
1a) IL #6 coal - base case	-	-	939	816
1b) with seq. of process CO_2	449	48%	490	426
1c) with seq. of process & comb. CO_2	516	55%	423	368
1d) with co-prod. of fuels & power	304	32%	635	552
1e) with co-proc. of biomass	155	17%	783	682
1f) with coalbed CH_4 capture	22	2.3%	917	798
1g) with co-proc. of coalbed CH_4	234	25%	705	613
4a) Pipeline natural gas - base case	-	-	562	489
4b) with seq. of process CO_2	65	12%	497	432
4c) with seq. of process & comb. CO_2	120	22%	442	384
5a) Venezuelan assoc. gas - base case	-	-	643	559
5b) with flaring credit	578	90%	65	57
5c) with venting credit	3234	503%	-2592	-2255
6a) ANS associated gas _ base case	-	-	652	567
6b) with seq. of process CO_2	94	14%	558	485
6c) with seq. of process & comb. CO_2	211	32%	441	383
6d) with co-prod. of fuels & power	119	18%	534	464

Table A36: Ultimate Analysis	HHV (MF)	LHV (MF)	% Moisture	% Ash (MF)	% C (MF)	% H (MF)	% N (MF)	% S (MF)	% Cl (MF)	% O (MF)	% Total (MF)	g CO_2/gal	g CO_2/ton	g CO_2/Mscf	g CO_2eq/Mscf
	M Btu/lb	M Btu/lb													
IL#6 Coal (Burning Star Mine)	12.246	11.945	8.60	11.49	71.01	4.80	1.40	3.19	0.10	8.01	O by diff.				
IL#6 Slag (Shell Gasifier)				95.04	3.36	0	0	1.44	0.16		100.00				
Wyo Coal (Powder River Basin)	11.645	11.198		8.71	67.84	4.71	0.94	0.58	0.01	17.21	O by diff.				
Wyo Slag (Shell Gasifier)				95.04	3.36	0	0	1.44	0.16		100.00				
SRWC (Maple Wood Chips)	8.083	7.724	37.9	0.50	49.54	6.11	0.10	0.02	0.00	43.73	100.00		1646900.67		
Biomass Slag (BCL Gasifier)				3.25	89.20	7.48	0.00	0.07	0.00	0.00	100.00				
Pipeline Natural Gas	23.077	20.823	0	0	73.75	23.97	0.95	nil	0	1.33	100.01				
Associated Gas (xx% CO2)	17.021	15.367	0	0	61.96	17.59	0.00	nil	0.00	20.45	100.00			55983.549	313521.43
Fuel Gas (Case 1)	5.18	4.74													
	7.45	6.90			36.54	6.02	17.53	0.00	0.00	39.92	0.00				
Fuel Gas (Case 4)															
S-Plant Flue Gas (Case 1,2,3)					24.93	4.25	0.86	0.05095	0.00	69.91	100.00				
S-Plant Flue Gas (Case 4)					23.80	2.67	9.98	0.03	0.00	63.52	100.00				
Hydrogen (H2)	61.0	51.6				100.00									
Nitrogen (N2)	0.0	0.0					100.00								
Carbon Monoxide (CO)	4.3	4.3			42.88					57.12	100.00				
Carbon Dioxide (CO2)	0.0	0.0			27.29					72.71	100.00				
Carbonyl Sulfide (COS)	4.0	4.0			19.99			53.37		26.64	100.00				
Water (H2O)	0.0	0.0				11.19				88.81	100.01				
Hydrogen Sulfide (H2S)	7.1	6.5				5.92		94.07			99.99				
Ammonia (NH3)	9.7	8.0				17.76	82.27				100.02				
Hydrogen Cyanide (HCN)					44.43	3.73	51.83				99.99				
Methanol (CH3OH)	9.8	8.6			37.48	12.58				49.94	100.01				
MTBE (C5H12O)	16.3	15.0			68.12	13.72				18.15	100.00				
TAME (C6H14O)	17.0	15.7			70.52	13.81				15.66	99.99				
Methane (CH4)	23.9	21.5			74.88	25.14					100.01				
Ethylene (C2H4)	21.3	20.3			85.63	14.37					100.01				
Ethane (C2H6)	22.3	20.4			79.88	20.11					99.99				
Propylene (C3H6)	21.0	19.7			85.62	14.37					100.00				
LPG (Propane - C3H8)	21.7	19.931			81.72	18.29					100.01				
Butanes (C4H10)	21.3	19.634			82.66	17.34					100.00				
Pentanes (C5H12)	20.9	19.3			83.23	16.77					99.99				
Hexanes (C6H14)	20.8	19.2			83.63	16.38					100.00				
95 RONC Reformate	17.6	16.8			88.11	11.60					99.71				

Table A36: Ultimate Analysis	HHV (MF)	LHV (MF)	% Moisture	% Ash (MF)	% C (MF)	% H (MF)	% N (MF)	% S (MF)	% Cl (MF)	% O (MF)	% Total (MF)	g CO_2/gal	g CO_2/ton	g CO_2/Mscf	g CO_2eq/Mscf
	M Btu/lb	M Btu/lb													
C5/C6 Isomerate (81 R+M/2)	20.1	18.5			83.44	16.49					99.93				
C3/C4/C5 Alkylate (92 R+M/2)	20.0	18.4			84.00	18.09					102.09				
ZSM-Gasoline	18.6	17.3			85.88	13.58					99.46				
Case 1 Gasoline	19.0	17.740			85.63	14.99					100.62	8551.98			
Case 2 Gasoline	19.4	17.962			85.05	15.35					100.41	8408.87			
Case 3 Gasoline	18.3	16.983			78.73	15.27				6.75	100.75	7825.33			
Case 4 Gasoline	19.0	17.741			85.63	14.99					100.62	8550.66			
Case 5 Gasoline	18.3	17.274			86.81	12.96					99.77	8813.61			
Case 6 Gasoline	18.8	17.610			85.95	14.39					100.34	8602.60			
FT-Derived Naphthas (C7-350'F)	20.7	19.100			84.60	15.40						8058.68			
FT-Derived Distillates (350'F+)	20.5	18.900			84.60	15.40						9011.05			
Case 3 Distillate	20.1	18.580			84.86	15.04						8956.28			

Appendix B:

Greenhouse-Gas Emissions Inventory Tables
Metric Units

Executive Summary Table
Full Life-Cycle GHG Emissions for FT & Petroleum Diesel
(g CO_2-eq/kilometer in SUV)

Resource	Extraction/ Production	Conversion/ Refining	Transport./ Distribution	End Use Combustion	Total Fuel Chain
IL #6 Coal - base case	16	337	1	229	583
- in advanced diesel*	37	293	1	199	507
Wyoming Coal	4	364	2	229	598
Plantation Biomass	-602	437	1	229	65
Pipeline Natural Gas	44	75	1	229	349
Venezuelan Assoc. Gas	32	132	7	229	400
- with flaring credit*	-327	132	7	229	40
ANS Associated Gas	32	132	13	229	405
Wyoming Sweet Crude Oil	14	46	5	226	291
Arab Light Crude Oil	22	50	16	228	316
ANS Crude Oil	17	63	9	235	324
Venezuelan Syncrude	20	89	6	242	357

*1.6093 kilometers = 1 mile

Table 1: Global Warming Potentials for Selected Gases
(kg of CO_2 per kg of Gas)

Gas	Lifetime (years)	Direct Effect over Time Horizons of:		
		20 Years	100 Years	500 Years
Carbon Dioxide (CO_2)	Variable	1	1	1
Methane (CH_4)	12 ± 3	56	21	7
Nitrous Oxide (N_2O)	120	280	310	170

Table 2: Indirect Liquefaction Baseline Design Data

Design	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8
Feedstock	IL #6	IL #6	IL #6	Wyo. Coal	Biomass	Pipeline Gas	Assoc. Gas	Assoc. Gas
Upgrading	Maximum Distillate	Increased Gasoline	Maximum Gaso. & Chem.	Maximum Distillate	Fuels & Power	Maximum Distillate	Minimum Upgrading	Min. Upgrading & Power
Raw Materials (tonne/day)								
Coal, Biomass, NG	16851	16851	16851	17953	2000	8119	12502	12502
Catalysts & Chemicals	310	348	na	357	na	2.65	na	na
Products (liters/day)								
Methanol			-366153					
Propylene			804489					
LPG	305579	417031	250091	303194	0	270919	0	0
Butanes	-494459	158672	-827383	-493028	0	-54057	0	0
Gasoline/Naphtha	3806698	4969232	6315401	3776966	60734	2707123	2448446	1923779
Distillates	3924827	2521263	1552378	3889849	123217	4167287	5373862	4245033
Products (tonne/day)								
Methanol			-291					
Propylene			417					
LPG	155	211	127	153	0	137	0	0
Butanes	-287	92	-482	-287	0	-32	0	0
Gasoline/Naphtha	2741	3542	4525	2719	44	1953	1681	1320
Distillates	3033	1961	1181	3006	95	3213	4126	3253
By-Products (tonne/day)								
Slag	2036	2036	2036	1585	209			
Sulfur	508	459	459	98				
CO_2 Removal	25804	25777	25822	25696		2967	4639	
CO_2 Carrier Gas	-3370	-3370	-3370	-3591				
S-Plant Flue Gas	985	985	985	316				
Utilities Consumed								
Electric Power (MW)	54.3	53	58	88	-86	-25	0	-372
Raw Water (m^3/day)	52996	52996	60567	37854	7571	79494	22713	15142

1 ton = 0.9072 tonnne; 1 bbl = 158.99 liters; 1 m^3 = 264 gallons

Table 3: Resource Consumption and Yields for FT Production
(Per m^3 of FT Liquid Product)

Design	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**	**Option 6**	**Option 7**	**Option 8**
Feedstock	IL #6	IL #6	IL #6	Wyo. Coal	Biomass	Pipeline Gas	Assoc. Gas	Assoc. Gas
Upgrading	Maximum Distillate	Increased Gasoline	Maximum Gaso. &Chem.	Maximum Distillate	Fuels & Power	Maximum Distillate	Minimum Upgrading	Min. Upgrading & Power
Resources								
Coal or Biomass (MF tonne)	2.10	2.09	1.89	2.25	3.54 [0.0041]			
Butanes (liter)	62		93	62		8		
Methanol (liter)			41					
Catalysts & Chemicals (kg)	358.7	440.5	na	448.2	na	3.7	na	na
Water Make-Up (m^3)	6.81	6.79	6.64	4.67	12.88 [0.0150]	10.83 [0.0220]	2.71	2.17 [0.0025]
Electric Power (kJ)	584292	563449	563094	953660	-40324528	-298868		-5207547
Volume Yield (liter)								
C3/C4 LPG	38	71	118	38		38		
Gasoline/Naphtha	474	616	708	474	330	379	313	312
Distillates	488	313	174	488	670	583	687	688
Mass Yield (tonne)								
C3/C4 LPG	0.0171	0.0403	0.6270	0.0170		0.0167		
Gasoline/Naphtha	0.3421	0.4396	0.5075	0.3421	0.2396	0.2736	0.2170	0.2170
Distillates	0.3767	0.2453	0.1314	0.3767	0.5195	0.4509	0.5252	0.5252
Slag (MF)	0.2509	0.2509	0.2283	0.20	0.3711			
Sulfur	0.6270	0.6270	0.5704	0.0113				
Energy Yield (MJ)								
C3/C4 LPG	893	1736	2799	887		887		
Gasoline/Naphtha	14069	18340	20031	14075	9710	11195	9547	9509
Distillates	16591	10503	5723	16579	22742	19767	23195	23189
Power					67207	849		8686
Allocation to Fuels					32.6%	97.4%		79.0%
Thermal Efficiency (LHV)	50.4%	52.0%	47.4%	49.3%	51.0%	59.1%	57.3%	57.1%
Carbon Efficiency	40.1%	41.1%	37.7%	39.1%	37.2%	57.0%	39.3%	39.2%

1 ton = 0.9072 tonnne; 1 bbl = 158.99 liters; 1 bbl = .15899 m^3; 1 lb = 0.4536 kg; 1 Btu = 1055.1 joules; MJ = megajoule

Table 4: Emissions Inventory for FT Production
(Per liter of FT Liquid Product)

Design	Option 1	Option 2	Option 3	Option 4	Option 5*	Option 6*	Option 7	Option 8*
Feedstock	IL #6	IL #6	IL #6	Wyo. Coal	Biomass	Pipeline Gas	Assoc. Gas	Assoc. Gas
Upgrading	Maximum Distillate	Increased Gasoline	Maximum Gaso. & Chem.	Maximum Distillate	Fuels & Power	Maximum Distillate	Minimum Upgrading	Min. Upgrading & Power
CO_2 (mg)	3360658	3312689	3189880	3617859	4446737	752797	1326899	584803
CH_4 (mg)	368	322	405	549	82	53	30	30
N_2O (mg)	14	12	13	18	104	10	13	20
SOx (mg)	1243	1200	1219	1875	0	0.4	0	0
NOx (mg)	560	453	618	747	3295	327	404	632
CO (mg)	99	74	113	120	800	79	98	154
VOC (mg)	386	291	479	573	141	24	17	27
PM (mg)	317	303	312	513	71	7	9	14

Table 5: Emissions Inventory for Power Exported from FT Plants
(Per MJ* of Electric Power)

Design		Option 5	Option 6	Option 8
Feedstock		Biomass	Pipeline Gas	Assoc. Gas
Upgrading		Fuels & Power	Maximum Distillate	Min. Upgrading & Power
CO_2	(mg)	228333	67500	29722
CH_4	(mg)	4.2	4.7	1.7
N_2O	(mg)	5.3	0.833	1.1
SOx	(mg)	0	0	0
NOx	(mg)	170	29.2	32.2
CO	(mg)	41.1	7.2	7.8
VOC	(mg)	7.2	2.2	1.4
PM	(mg)	3.6	0.56	0.56

*MJ = megajoule = 1e6 joules

Table 6: GHG Emissions from FT Production
(Per liter of FT Liquid Product)

Design	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5***	**Option 6***	**Option 7**	**Option 8***
Feedstock	IL #6	IL #6	IL #6	Wyo. Coal	Biomass	Pipeline Gas	Assoc. Gas	Assoc. Gas
Upgrading	Maximum Distillate	Increased Gasoline	Maximum Gaso. & Chem.	Maximum Distillate	Fuels & Power	Maximum Distillate	Minimum Upgrading	Min. Upgrading & Power
CO_2 – vented gas (mg)	2791373	2777860	2516260	2773585	0	404356	593084	0
CO_2 – combustion flue gas (mg)	299928	280131	414687	579165	4446736	343198	727884	584803
CO_2 – incineration flue gas (mg)	111976	111573	100866	34549	0	0	0	0
CO_2 – fugitive emissions (mg)	32107	31957	28940	32241	0	4044	5931	0
CO_2 – ancillary sources (mg)	125271	111168	129127	198319	0	1198	0	0
CH_4 – combustion flue gas (mg CO_2-eq)	92	74	91	93	1417	138	173	272
CH_4 – fugitive & flaring (mg CO_2-eq)	912	912	912	912	297	888	456	360
CH_4 – ancillary sources (mg CO_2-eq)	6730	5769	7503	10522	0	90	0	0
N_2O – combustion flue gas (mg CO_2-eq)	2084	1676	2062	2101	32172	3124	3940	6172
N_2O – ancillary (mg CO_2-eq)	2122	2042	2055	3463	0	1	0	0
Total (mg CO_2-eq)	3372595	3323162	3202504	3634950	4480622	757037	1331468	591607

Table 8: Ultimate Analyses of Coal and Biomass

	Illinois #6 Coal	Wyoming Coal	Maplewood Chips
HHV (kJ/kg)	28494	27099	18795
LHV (kJ/kg)	27797	26052	17957
	Wt. %	**Wt. %**	**Wt.%**
Moisture	9.41	44.9	61.0
Ash	11.49	8.71	0.50
C	71.01	67.84	49.54
H	4.80	4.71	6.11
N	1.40	0.94	0.10
S	3.19	0.58	0.02
Cl	0.10	0.01	0.00
O (by diff.)	8.01	17.21	43.73

Table 9: Resource Consumption for Coal Production
(Per tonne of MF Coal Produced)

	Illinois #6 Underground Mine	Illinois #6 Surface Mine	Wyoming Surface Mine
Electricity (kJ)	50120	56281	56674
Distillate Fuel (liter)		0.290	0.292
Water Make-Up (liter)	215	158	153
Limestone (kg)	17.5		
Ammonium Nitrate (kg)		2.23	2.25
Refuse (tonnne)	-.310	-.310	-.310

*Positive value is consumed, negative is produced.

Table 10: Coalbed Methane Emissions
(Per tonne of MF Coal Produced)

	Illinois #6 Underground Mine	Illinois #6 Surface Mine	Wyoming Surface Mine
CH_4 (N liter)	3526	2188	180
CH_4 (mg)	2521232	1564471	128668

Table 11: Emissions Inventory for Coal Production
(Per tonne of MF Coal Produced)

		Illinois #6 Underground Mine	Illinois #6 Surface Mine	Wyoming Surface Mine
CO_2	**(mg)**	9892240	11133517	11211290
CH_4	**(mg)**	2545680	1591925	156314
N_2O	**(mg)**	586	659	663
SOx	**(mg)**	96341	108327	109083
NOx	**(mg)**	25060	28434	28633
CO	**(mg)**	2854	3331	3355
VOC	**(mg)**	25200	28318	28516
PM	**(mg)**	26591	29822	30091

Table 12: Greenhouse Gas Emissions from Coal Production
(Per tonne of MF Coal Produced)

		Illinois #6 Underground Mine	Illinois #6 Surface Mine	Wyoming Surface Mine
CO_2	**(mg)**	9892240	11133517	11211290
CH_4	**(mg CO_2-eq)**	53459274	33430431	3282593
N_2O	**(mg CO_2-eq)**	181698	204228	205655
Total	**(mg CO_2-eq)**	63533212	44768176	14699538

Table 13: Emissions Inventory for Biomass Production
(Per tonne of MF Biomass Produced)

		Feedstock Sequestering	Cultivation & Harvesting	Local Transportation	Total
CO_2	**(g)**	-1495281	47476	9219	-1438618
CH_4	**(g)**		7.55	0.35	7.9
N_2O	**(g)**		15.3	0.36	15.7
SOx	**(g)**		na	na	na
NOx	**(g)**		279	44.8	323
CO	**(g)**		112.5	18.1	130.6
VOC	**(g)**		117.3	13.3	130.6
PM	**(g)**		na	na	na

Table 14: Greenhouse Gas Emissions from Biomass Production
(Per tonne of MF Biomass Produced)

		Feedstock Sequestering	Cultivation & Harvesting	Local Transportation	Total
CO_2	(g CO_2)	-1495313	47477	9219	-1438618
CH_4	(g CO_2-eq)		159	7.4	166
N_2O	(g CO_2-eq)		4753	113	4865
Total	(g CO_2-eq)	-1495313	52388	9339	-1433586

Table 15: Composition of Associated & Pipeline Natural Gas

	Associated Gas	Pipeline Gas
HHV (kJ/N liter)	36.4	39.5
LHV (kJ/N Liter)	32.9	35.6
	Vol. %	Vol. %
Methane	76.2	94.7
Ethane	6.4	3.2
Propane	3.2	0.5
Isobutane	0.3	0.1
n-Butane	0.8	0.1
C_5+	0.1	0.1
CO_2	12.6	0.7
H_2S	-	-
N_2	0.4	0.6

Table 16: Emissions Inventory for Natural Gas Production
(Per Normal Liter of Natural Gas Produced)

		Associated Gas	Pipeline Gas
CO_2	(mg)	165	238
CH_4	(mg)	0.851	2.57
N_2O	(mg)	0.0056	0.0078
SOx	(mg)	na	0.0078
NOx	(mg)	1.26	1.81
CO	(mg)	0.3060	0.4403
VOC	(mg)	2.0	2.87
PM	(mg)	0	0

Table 17: Greenhouse Gas Emissions from Natural Gas Production
(Per Normal Liter of Natural Gas Produced)

		Associated Gas	Pipeline Gas
CO_2	**(mg CO_2)**	165	238
CH_4	**(mg CO_2-eq)**	18	54
N_2O	**(mg CO_2-eq)**	1.69	2.42
Total	**(mg CO_2-eq)**	185	295

Table 18: Energy Consumption for Different Modes of Transportation
(Per tonne-km Transported)

Truck	Tanker	Tank Car	Pipeline
kJ	kJ	kJ	kJ
1130	243	307	71.4

Table 19: Emissions Inventory for Transportation Scenarios 1, 3 & 4
(Per liter of FT Fuel Transported)

Transportation Mode		Truck	Tanker	Pipeline	Total
Southern Illinois to Chicago		DFO	RFO	Electricity	
	Kilometers	97	0	322	419
CO_2	**(mg)**	7474	0	1321	8795
CH_4	**(mg)**	0.40	0	3.27	3.67
N_2O	**(mg)**	0.24	0	0.07	0.32
SOx	**(mg)**	36.7	0	12.86	49.6
NOx	**(mg)**	32.3	0	4.88	37.2
CO	**(mg)**	43.3	0	1.56	44.8
PM	**(mg)**	6.21	0	3.55	9.76
VOC	**(mg)**	0.28	0	0.04	0.32

Table 20: Emissions Inventory for Transportation Scenario 2
(Per liter of FT Fuel Transported)

Transportation Mode		**Truck**	**Tanker**	**Pipeline**	**Total**
Wyoming to Chicago		DFO	RFO	Electricity	
	Kilometers	97	0	1609	1706
CO_2	**(mg)**	7474	0	6605	14080
CH_4	**(mg)**	0.40	0	16.34	16.7
N_2O	**(mg)**	0.24	0	0.37	0.61
SOx	**(mg)**	36.7	0	64.3	101
NOx	**(mg)**	32.3	0	24.4	56.7
CO	**(mg)**	43.3	0	7.81	51.1
PM	**(mg)**	6.21	0	17.7	24.0
VOC	**(mg)**	0.28	0	0.18	0.46

Table 21: Emissions Inventory for Transportation Scenario 5
(Per liter of FT Transported)

Transportation Mode		**Truck**	**Tanker**	**Pipeline**	**Total**
Venezuela to Chicago		DFO	RFO	Electricity	
	Kilometers	97	3219	1931	5246
CO_2	**(mg)**	7474	57571	7926	72971
CH_4	**(mg)**	0.40	76.5	19.6	96.5
N_2O	**(mg)**	0.24	1.32	0.44	2.01
SOx	**(mg)**	36.7	723	77.2	836
NOx	**(mg)**	32.3	189	29.3	251
CO	**(mg)**	43.3	33.0	9.37	85.6
PM	**(mg)**	6.20	43.6	21.3	71.1
VOC	**(mg)**	0.28	28.5	0.21	30.0

Table 22: Emissions Inventory for Transportation Scenarios 6
(Per liter of FT Fuel Transported)

Transportation Mode		Truck	Tanker	Pipeline	Total
ANS to San Francisco		DFO	RFO	Electricity	
	Kilometers	97	6647	1287	8031
CO_2	**(mg)**	7474	118883	5284	131642
CH_4	**(mg)**	0.40	158	13.1	171
N_2O	**(mg)**	0.24	2.74	0.30	3.28
SOx	**(mg)**	36.7	1492	51.4	1580
NOx	**(mg)**	32.3	390	19.5	442
CO	**(mg)**	43.3	68.0	6.24	117
PM	**(mg)**	6.21	90.1	14.2	111
VOC	**(mg)**	0.28	58.8	0.14	29.2

Table 23: Greenhouse Gas Emissions from Transportation
(Per liter of FT Fuel Transported)

		Truck	Tanker	Pipeline	Total
Scenario 1, 3 & 4	**(g CO_2-eq)**	7.56	0	1.41	8.97
Scenario 2	**(g CO_2-eq)**	7.56	0	7.10	14.62
Scenario 5	**(g CO_2-eq)**	7.56	59.6	8.47	75.6
Scenario 6	**(g CO_2-eq)**	7.56	123.1	5.65	136.3

Table 24: Emissions Inventory for Ancillary Feedstocks

	Electricity	Diesel Truck	Heavy Equip.	Tanker	Fuel Gas	Butane	Methanol
	Delivered	Delivered & Consumed	Delivered & Consumed	Delivered & Consumed	Consumed	Delivered	Delivered
	(mg/MJ)	(mg/MJ)	(mg/MJ)	(g/MJ)	(g/MJ)	(mg/L)	(mg/L)
MJ/L		38.7	38.7	41.7			
CO_2	197500	76299	76299	82153	Calculated	162645	70269
CH_4	489	4.1	4.1	14.4	1.2	579	704
N_2O	11.7	2.5	1.9	1.9	1.9	5.3	10.0
SOx	1922	375	430	1031	0.0	50.9	642
NOx	500	330	888	775	60.3	937	1038
CO	56.9	442	383	287	14.6	218	238
VOC	503	88.3	64.8	144.1	2.6	1352	1415
PM	531	63.4	66.8	92.4	1.3	42.1	69.8

MJ = megajoule = 1e6 joules

Table 25: CO_2 Emissions from Combustion of Selected Fuels

FT Gasoline/Naphtha	**Wt. % C**	**g CO_2/L**
Design Option 1	85.63	2259
Design Option 2	85.05	2220
Design Option 3	78.73	2067
Design Option 4	85.63	2259
Design Option 5	86.81	2328
Design Option 6	85.95	2273
Design Options 7, 8	84.60	2129
FT Distillate		
Design Options 1, 2, 4-8	84.60	2381
Design Option 3	84.86	2366
	Wt. % C	**g CO_2/N liter**
Flared Associated Gas	61.96	2.09
	Wt. % C	**g CO_2-eq/N liter**
Vented Associated Gas	61.96	11.7

Table 26: Vehicle Fuel Economy-Technology Matrix

(Kilometers-per-liter)

Spark Ignition									
Conventional	4.3	6.4	8.5	10.6	12.8	14.9	17.0	19.1	21.3
Hybrid Electric	6.9	10.4	13.8	17.3	20.7	24.2	27.6	31.1	34.6
Direct Injection	5.4	8.1	10.8	13.4	16.2	18.8	21.5	24.2	26.9
Hybrid/Direct Inject	8.2	12.2	16.4	20.5	24.5	28.6	32.7	36.8	40.9
Compression Ignition									
Conventional	5.7	8.5	11.3	14.2	17.0	19.8	22.7	25.5	28.3
Advanced	6.5	9.8	13.0	16.3	19.6	22.8	26.1	29.3	32.6
Hybrid Electric	8.5	12.8	17.1	21.3	25.6	29.8	34.1	38.4	42.6
Advanced Hybrid	9.8	14.7	19.6	24.5	29.4	34.3	39.2	44.1	49.0

Table 27: Emissions Inventory for FT Fuels at Point of Sale
(Per liter of FT Fuel Supplied)

		Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
CO_2	**(g)**	3395	3663	-1734	1119	1687	1746
CH_4	**(g)**	6.86	0.99	0.12	3.93	1.60	1.68
N_2O	**(g)**	0.02	0.02	0.17	0.02	0.02	0.03
SOx	**(g)**	1.54	2.27	0.05	0.06	0.84	1.58
NOx	**(g)**	0.66	0.88	4.72	3.08	2.84	3.03
CO	**(g)**	0.15	0.18	1.41	0.79	0.72	0.75
VOC	**(g)**	0.45	0.65	0.70	4.35	3.52	3.55
PM	**(g)**	0.39	0.62	0.08	0.02	0.08	0.12

Table 28: Full Life-Cycle GHG Emissions for FT Diesel
(g CO_2-eq/kilometer in SUV)

Scenario/ FT Feedstock Source	Extraction/ Production	Conversion/ Refining	Transport./ Distribution	End Use Combustion	Total Fuel Chain
1) IL #6 Coal	16	337	1	229	583
2) Wyoming Coal	4	364	1	229	598
3) Plantation Biomass*	-602	437	1	229	65
4) Pipeline Natural Gas	44	75	1	229	349
5) Venezuelan Assoc. Gas	32	132	7	229	399
6) ANS Associated Gas	32	132	13	229	405

Table 29: Full Life-Cycle GHG Emissions for Power Exported from FT Plants
(g CO_2-eq/MJ of Electric Power)

Scenario/ FT Plant Feedstock	All Upstream	Electricity Generation	Total Fuel Chain	Electric Efficiency
3) Plantation Biomass	-316	230	-86	60%
4) Pipeline Natural Gas	39	68	107	35%
6d) ANS Associated Gas	16	30	47	60%
U.S. Average All Plants	21	190	211	-
U.S. Average PC Plants	14	276	290	32%
NSPS PC Plant	13	255	268	35%
LEBS PC Plant	6	201	206	42%
Biomass Gasification Combine-Cycle	-237	247	11	37%

Table 30: Life-Cycle Sensitivity Analysis for FT Diesel

($g\ CO_2$-eq/kilometer in SUV)

Scenario/ FT Feedstock Source	GHG Emissions Reduction		Total Fuel Chain	
			existing diesel engine	advanced diesel engine
1a) IL #6 coal - base case	-	-	583	507
1b) with seq. of process CO_2	279	48%	304	265
1c) with seq. of process & comb. CO_2	321	55%	263	229
1d) with co-prod. of fuels & power	189	32%	395	343
1e) with co-proc. of biomass	96	17%	487	424
1f) with coalbed CH_4 capture	14	2.3%	570	496
1g) with co-proc. of coalbed CH_4	145	25%	438	381
4a) Pipeline natural gas - base case	-	-	350	304
4b) with seq. of process CO_2	40	12%	309	268
4c) with seq. of process & comb. CO_2	75	22%	275	239
5a) Venezuelan assoc. gas - base case	-	-	400	347
5b) with flaring credit	359	90%	40	35
5c) with venting credit	2010	503%	-1611	-1401
6a) ANS associated gas _ base case	-	-	405	352
6b) with seq. of process CO_2	58	14%	347	301
6c) with seq. of process & comb. CO_2	131	32%	274	238
6d) with co-prod. of fuels & power	74	18%	332	288

Table 31: Full Life-Cycle GHG Emissions for Petroleum Diesel

($g\ CO_2$-eq/kilometer in SUV)

Crude Oil Source	Extraction/ Production	Conversion/ Refining	Transport./ Distribution	End Use Combustion	Total Fuel Chain
Wyoming Sweet (40^oAPI)	14	46	5	226	291
Canadian Light	19	50	7	228	304
Brent North Sea (38^o)	14	50	5	228	298
Arab Light (38^o)	22	50	16	228	316
Alaska North Slope (26^o)	17	63	9	235	324
Alberta Syncrude (22^o)	20	65	6	230	321
Venezuelan Heavy Oil (24^o)	20	67	8	237	332
Venezuelan Syncrude (15^o)	20	89	6	242	357

A guide to life-cycle greenhouse gas (GHG) emissions from electric supply technologies

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Abstract: This manuscript reviews and compares the results of recent greenhouse gas (GHG) emission life-cycle analyses. Specific attention is paid to fossil energy technologies, nuclear and renewable energy technologies (RETs), as well as carbon capture and storage (CCS) and energy storage systems. Analysing up-and downstream processes and their associated GHG emissions, which arise upstream and downstream of the power plant (i.e., electricity generation stage), is important; otherwise, the GHG emissions resulting from electricity generation of the various fuel options are underestimated. For fossil fuel technology options upstream GHG emission rates can be up to 25% of the direct emissions from the power plant, whereas for most RETs and nuclear power upstream and downstream GHG emissions can account for way over 90% of cumulative emissions. In economies where carbon is being priced or GHG emissions constrained, this may provide an advantage to technologies with trans-boundary upstream emissions over technologies without significant life-cycle emissions arising outside the legislative boundaries of GHG mitigation policies. It is therefore desirable for GHG emissions under national, regional and international mitigation policies to be accounted for over its entire life-cycle. The results presented here indicate that the most significant GHG avoidance (in absolute terms) can be made from technology substitution. The introduction of advanced fossil fuel technologies can also lead to improvements in life-cycle GHG emissions. Overall, hydro, nuclear and wind energy technologies can produce electricity with the least life-cycle global warming impact.

Keywords: *greenhouse gas emission, life-cycle analysis / assessment, energy technology, electricity, fossil fuels, renewable energy technologies, global warming, climate policy, nuclear energy chain*

1 Introduction

All energy systems emit greenhouse gases (GHG)[1] and contribute to anthropogenic climate change. It is now widely recognised that GHG emissions resulting from the use of a particular energy technology need to be quantified over all stages of the technology and its fuel life-cycle. While accurate calculation of GHG emissions per kilowatt-hour (kWh) is often difficult, sound knowledge of life-cycle GHG emissions can be an important indicator for mitigation strategies in the power sector.

To date a great variety of GHG life cycle assessments (LCA) of power plants has been conducted. For example, Van de Vate reports on the status of life-cycle GHG emissions from hydropower [1] and energy sources [2] based on International Atomic Energy Agency (IAEA) expert meetings, Frankl et

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[1] Each GHG has active radiative (or heat-trapping) properties. To compare GHGs emissions from different sources, they are indexed according to their global warming potential. Global warming potential (GWP) is the ability of a GHG to trap heat in the atmosphere relative to an equal amount of carbon dioxide. According to the Intergovernmental Panel on Climate Change (IPCC), over a 100-year time span carbon dioxide (CO_2) assumes the value of 1. The two other GHGs of importance in this analysis are methane (CH_4) and nitrous oxide (N_2O) which, according to a re-evaluation of the IPCC in 2001, take a value of 23 and 296 respectively. Prior to 2001 the IPCC has assumed a 100 year GWP of 21 and 310 for CH_4 and N_2O respectively, which may explain for some minor differences in the results of studies preceding 2001.

al [3] on Photovoltaic (PV), Kreith et al [4] on fossil and solar power plants, Proops et al al [5] on various types of electricity generation, Yasukawa et al [6] on nuclear power and the nuclear fuel cycle, and Uchiyama [7] on several electricity generation and supply systems. Dones, Gantner and Hirschberg [8] evaluated GHG emissions from electricity and heat supply systems. There are many more. While on one hand, all of these *older* studies have helped shed light on the cumulative GHG emissions of power generation, on the other hand, their sometimes significantly different results – especially at individual upstream or downstream stages of the life-cycle – have created confusion amongst policy makers and scholars alike as to their accuracy or application.

This paper presents and analyses the life-cycle GHG emission of electricity generation chains (i.e. single and country / region averages) based on *recently* published assessments, and identifies the underlying mechanisms, that frequently lead to conflicting life-cycle emission results in these studies, such as methodological approach, geography of fuel supply and mixes, heating values and carbon emission factors, system boundary assumptions etc. Appreciating and understanding the discrepancies in these results is crucial for GHG LCA to play a role in guiding policy. In addition, the implications of life-cycle GHG emissions for climate policy are discussed since most policies address the release of GHG emissions by focusing on large-scale stationary point-sources, thereby potentially failing to embrace significant up- and downstream emissions outside those well-defined boundaries.

The second section in this analysis briefly discusses some aspects of the data and studies that have been used. The third section analyses *direct* emissions from fossil fuel power plants in different regions of the world to illustrate, that significant variations in GHG emission per unit of electricity exist for same fuel technologies due to technology specification, thermal efficiency and heating value. The fourth section discusses commonly used methodologies for LCA, as well as the benefits and limitations of LCA in general and specific to the methodology used. The fifth section discusses the results of the GHG LCA of several studies for conventional fossil fuel technologies, nuclear power, wind, PV, hydro and biomass. Further, the life-cycle GHG emissions for storage technologies and carbon capture and storage (CCS) are analysed.

The results presented here are *generic*, since the comparison of results presents an overview of emissions that can be usually expected. However, variations exist according to site-specific conditions (e.g. technology, carbon content of fuel, climatic conditions etc.). This comparison can be practical for policymakers, since policy decisions are often required before detailed site-specific information becomes available [9].

2 Use of data & studies

In this work, life-cycle emissions are presented for current power generation technologies, although some estimation of GHG emissions for advanced and future technologies is provided. The size of the plants is not considered unless specified and typical conditions are provided for Europe, North America, and Japan and in one case, China. Only original studies have been used to ensure that all data can be traced back to the original references. The LCA studies and reports used here were published between 2000 and 2006. The only exception is the results taken from Spadaro et al [10], which were developed in the mid-late nineties in a series of IAEA advisory group meetings to assess the life-cycle GHG emissions for different electricity generating options.

By and large the emphasis is on recent publications only since:

- LCA evolves in detail and complexity since its inception, thereby improving the accuracy of LCA results
- Energy/emission and input/output conditions in upstream and downstream processes change with time due to, for instance, regulation and efficiency improvements [11]
- Technology experience curves potentially render older LCA inappropriate for reference use today, since the associated GHG emissions have fallen, especially for some RETs where the energy pay-back-ratio has improved significantly and continues to improve.

It is important to note that this review has neither judged the quality of recently published LCAs nor systematically compared their consistency (e.g. boundaries or inclusiveness). It is also noteworthy to stress that while some of the studies focused only on GHG, others are to various degrees (much) more comprehensive by quantifying additional external impacts.

For clarification of terms, the sum of the emissions from all life-cycle stages is called *cumulative emission*. All processes and associated emissions but power plant operation are categorised in *upstream* (e.g. fuel exploration, mining, fuel transport) and *downstream* (e.g. decommissioning, waste management and disposal) groups. Emissions from power plant operation are referred to as *direct*. However, the different studies summarised here may use different boundaries (i.e. not consistent) for up- and downstream evaluation of production and energy chains.

3 Direct Emissions from Fossil Fuels

The principle factors determining the GHG emissions from a fossil fuel power plant is the type of technology (and hence choice of fuel) and its thermal efficiency. In addition, thermal efficiency (by and large) increases with the load factor (although efficiency reductions can be observed towards achieving full load operation) and therefore GHG emissions from a particular fossil fuel technology will depend on the mode of its operation (e.g. peak load management, base load supply, combined heat and power supply etc.) [10, 12].

Figure 1 illustrates two graphs. On the left, GHG emissions per kWh_e are depicted for four standard coal technologies (i.e. pulverised fuel (PF), fluidised bed combustion (FBC), integrated coal gasification combined cycle (IGCC) and steam turbine condensing (STC)) and one standard gas power plant type (i.e. combined cycle gas turbine (CCGT)) highlighting that among coal-fired power plants great variations in emissions exist (with the IGCC technology being the best performer), whereas for CCGT technologies the variation is much narrower. With regard to coal fired power plants it is important to note that currently IGCC technology has a comparable efficiency to Ultra Super Critical Pulverized Combustion coal power plants, which is the best available pulverised coal power plant. The large spread that can be observed for PF power plants is due to the fact that only some of the plants analysed here are super critical (in which case emissions tend to be lower) and others are using lignite as a fuel (in which case emissions tends to be higher). The graph on the right shows a strong correlation between GHG emissions and the net thermal efficiency of a coal fired power plant. The data is based on actual emissions from 44 power plants in OECD countries, as well as Bulgaria, Romania and South Africa.

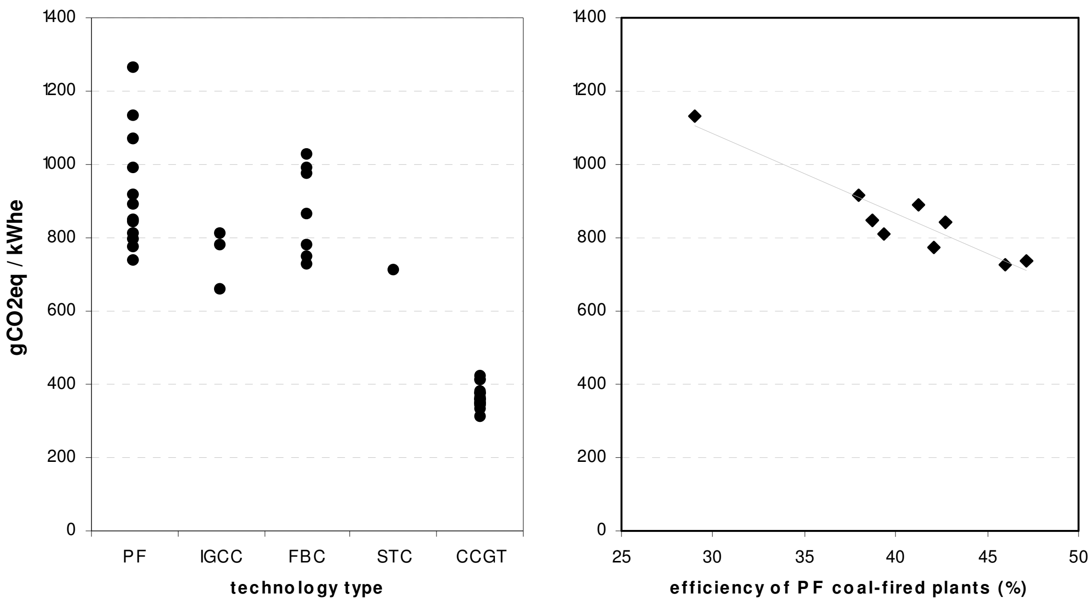

Figure 1: Direct GHG emissions from coal / gas power plant operation
Source: based on data from [13]

In addition to thermal efficiency and plant technology, which in part are intrinsically linked, the carbon content of the fuel plays an important role in determining direct GHG emissions. Figure 2 shows the relationship between the lower heating value (LHV) (i.e. net calorific value MJ/kg) and carbon content per unit of energy. All three series indicate the existence of a correlation that the carbon content increases with a decrease in the net calorific value. The two samples in the top left quadrant represent the reference values for different liquid and gaseous fuels from the Intergovernmental Panel on Climate Change (IPCC) [14], whereas the values in the bottom right quadrant represent different types of hard and brown coal in Europe are adopted from Fott [15]. Subsequently it can be stated that typically *the higher the heating value the lower the carbon content of the fossil fuel*.

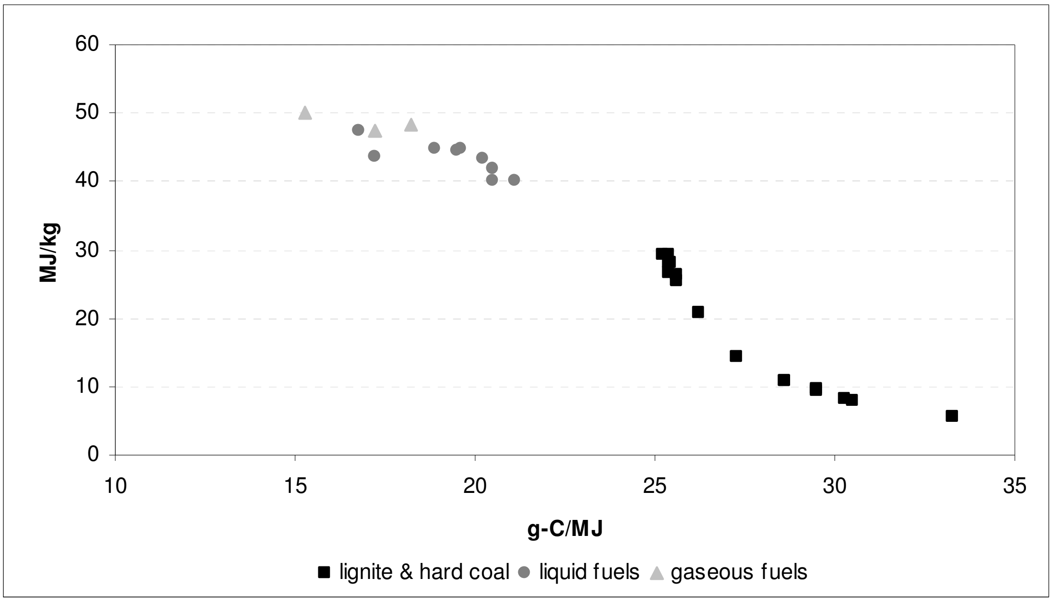

Figure 2: Correlation between heating value and carbon content
Source: based on data from [14, 15]

Figure 3 exemplifies the range of heating values that have been recorded for different fossil fuels for different countries. For example, the LHV in Spain is approximately 20% lower than in Germany. The LHV of lignite in Greece is only 40% of that in Austria, and the LHV of natural gas in the Netherlands is only 80% of the LHV in Algeria and Norway. With regard to Figure 2 & 3 it becomes apparent then, that the origin of the fuel can have a significant impact on the carbon release during combustion.

A similar assessment has been made for Europe by Dones et al [17] – where coal use is from eight regions: Western and Eastern Europe, North and South America, Australia, Russia, South Africa and Far East Asia – recording the lower heating value for hard coal between approximately 18-25.2 MJ/kg, and in the range of 4.7 to 14.9 MJ/kg for lignite.

This section illustrated that direct emissions from fossil fuel power plants are dependent on thermal efficiency, mode of operation, technology type and the carbon content of the fuel. Since more efficient technologies are – at least initially – more costly than less efficient power plants, and fuel with higher heating value pricier than fuels with a lower heating value, it is not surprising to find direct emissions to be lower in countries with higher levels of gross domestic product (GDP) compared with countries of lesser economic wealth. Figure 4 illustrates this assertion showing that the average direct emissions from Annex I[2] and Annex B[3] countries for power plants based on oil, gas and coal are significantly lower than emissions from Non-Annex I[4] countries.

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[2] Annex-I are the industrialized countries listed in the annex to the United Nations Framework Conference on Climate Change (UNFCCC) sought to return their greenhouse-gas emissions to 1990 levels by the year 2000 as per Article 4.2 (a) and (b). They include the 24 original OECD members, the European Union, and 14 countries with economies in transition. (Croatia, Liechtenstein, Monaco, and Slovenia joined Annex 1 at COP-3, and the Czech Republic and Slovakia replaced Czechoslovakia.) (Definition based on UNFCCC)

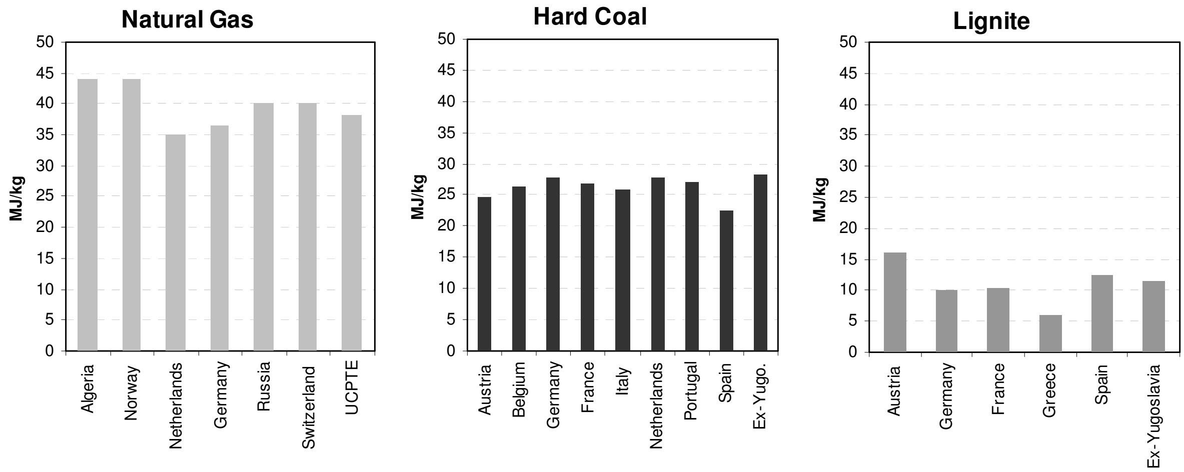

Figure 3: Lower heating values of fossil fuels for selected countries
Source: based on data reported in [16]

What the above analysis shows is that significant variation in direct emissions exists between same fuel technologies due to the various factors introduced above. Quantified emissions are therefore extremely site-specific depending on operating, technology and input conditions of the fuel and can therefore not be generalised to reflect average stack-emissions. Significant variation in emissions can also occur at the upstream and downstream stages of the technology and fuel-cycle from all energy technologies. The following section introduces the methods typically used for assessing full-life cycle impacts.

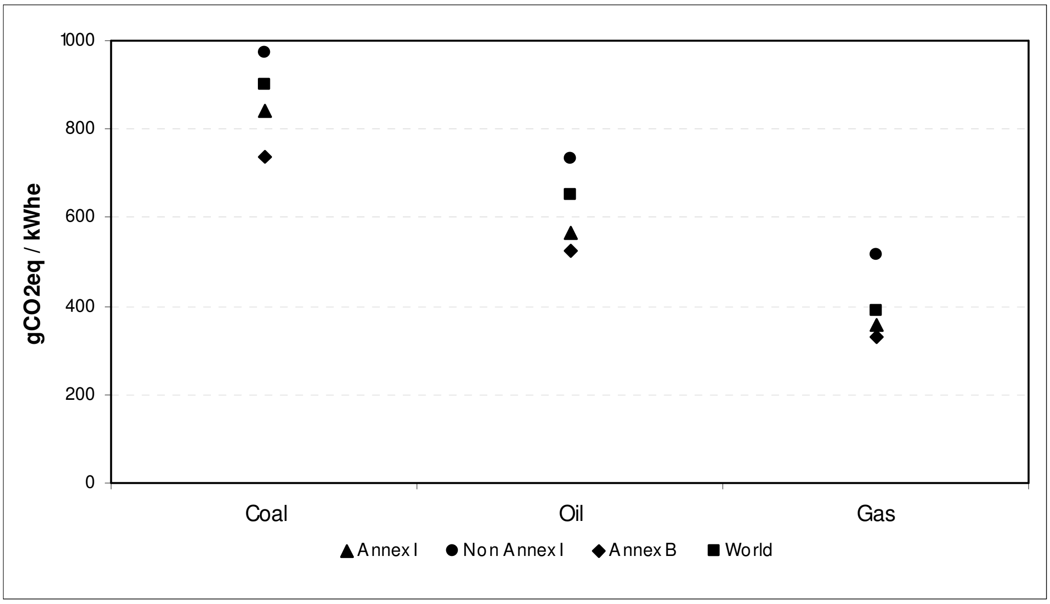

Figure 4: Direct GHG emission of UNFCCC and Kyoto country-groups
Source: based on data from IEA [13]

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[3] Annex-B countries are the 39 emissions-capped industrialised countries and economies in transition listed in Annex B of the Kyoto Protocol. Legally-binding emission reduction obligations for Annex B countries range from an 8% decrease (e.g., various European nations) to a 10% increase (Iceland) in relation to 1990 levels during the first commitment period from 2008 to 2012. Note that Belarussia and Turkey are listed in Annex I but not Annex B; and that Croatia, Liechtenstein, Monaco and Slovenia are listed in Annex B but not Annex I. (Definition based on UNFCCC)

[4] Non-annex-I refers to countries that have ratified or acceded to the United Nations Framework Convention on Climate Change that are not included in Annex I of the Convention. (Definition based on UNFCCC)

4 Assessment Methods

LCA investigates the environmental impacts throughout the full life-cycle of a product or system. Since environmental awareness and regulations are growing, LCA can improve the efficacy of environmental regulation since it can pin-point with great certainty the source of, for example, environmental pollution or resource use of upstream and downstream processes.

GHG LCA can provide information during which stage of the life-cycle significant emissions occur and therefore aid policymakers and stakeholders in focussing efforts where they are most effective in reducing GHG emissions [24]. When deciding between two or more alternatives, LCA can help decision-makers to compare the total cumulative emissions originating from a choice of technologies per unit of electricity. In addition to their use as a tool for decision-making LCA can be used for informing consumers, education, marketing etc. (e.g. environmental labelling, environmental product declaration) [24].

When comparing LCA GHG emission results of various energy chains it is necessary to understand that electricity generating options may not be true alternatives to each other. For instance, services provided by some energy technologies like irrigation and flood control, reliability of supply, and ancillary services such as voltage control, regulation, operating reserve, load-following and system black-start capability may not be easily provided by all technologies [9]. For example, intermittent RETs are not at the same level as other *firm* technologies, since they are rarely able to provide system/network services and may need backup either in the form of energy storage or additional spinning reserves [9, 24].

Furthermore, when using GHG LCA results from energy technologies it should be remembered that all the other biophysical effects and associate impacts of power generation, such as technical performance, cost or political and social acceptance have not been considered, which would be necessary for a truly holistic assessment. For example, common life cycle impact categories in addition to GHG emissions are [25]:

1. Stratospheric ozone depletion
2. Acidification
3. Eutrophication
4. Photochemical smog
5. Terrestrial toxicity
6. Aquatic toxicity
7. Human health
8. Resource depletion
9. Land use

In the case of GHG emissions from electricity generation all significant emissions related to the final product need to be accounted. For electricity this is usually expressed in grams of carbon dioxide equivalent per unit of busbar electricity (i.e. gCO_2/kWh_e). Typically (depending on the type of technology under investigation) LCA would account for GHG emissions at the following stages [18]:

- Energy resource exploration, extraction and processing
- Raw materials extraction for technology and infrastructure
- Production of infrastructure and fuels
- Production and construction of technology
- Transport of fuel
- Other related transport activity (e.g. during construction, decommissioning)
- Conversion to electricity or heat or mechanical energy
- Waste management and waste management infrastructure (e.g. radioactive waste depositories, ash disposal etc.)

LCA methods are generally distinguished between process chain analysis (PCA) and input/output (I/O), although hybrid assessment tools (using elements of both) are also frequently used. Performing an LCA can be resource- and time-intensive, and depending on the system boundaries and the availability of data can greatly impact on the accuracy of the final results [24]. Also, the reliability of LCA results depends strongly on assumptions on lifetime, yield, thermal efficiency, fuel etc.

PCA is a *vertical bottom-up* technique that considers emissions of particular industrial processes and operations and includes a limited order of supplying industries and their corresponding emissions, and is therefore an accurate but resource intensive undertaking. Although, PCA is specific to a particular type of production, and valid only for a well defined system boundary (typically chosen with the understanding that the addition of successive upstream and/or downstream stages may have negligible effects on the total cumulative GHG emissions) [19], it does make the contributing factors to cumulative results more transparent, and modifications through sensitivities easier.

PCA strongly relies on GHG content data being available for all relevant materials and processes [20], when in fact complete material inventories are not always available, and manufacturing data for complete systems difficult to estimate – in which case a hybrid approach could use PCA for material assessments and I/O to derive data for certain system operation and maintenance (O&M), manufacturing steps and other processes where complete information is not available [21]. Although more recently, detailed process analysis LCA data for several products of different sectors are increasingly available through commercial LCA tools [50].

Since PCA cannot practically consider the entire economy it was recognised that PCA carry systematic errors due to the unavoidable truncation of the system boundary resulting in a slight underestimation of energy inputs [19, 22]. However, these errors may be very small. In fact, the uncertainties in the approximations used throughout the complex modelling of different energy chains are likely to be higher than the error for underestimations of likely marginal contributions.

By way of contrast, the I/O method is a *statistical top-down* approach, which divides an entire economy into distinct sectors. Based on economic inputs and outputs between the sectors, I/O generates the energy flows and the associated emissions [17]. For example, an established I/O database provides estimates of the amount of energy required to manufacture classes of products and provides categories of services [21]. However, specific sectors do not exist in I/O table and must be modelled using PCA. In addition, I/O sectors may be too generic, thus not matching the goal of an LCA. Unlike PCA, I/O analysis makes tracking of the 'hot spots' more difficult. Nonetheless, an advantage of I/O is that it does not have a case-dependency as is inherent to PCA, since it deals with aggregates [20], although I/O can inhibit inaccuracies when the actual energy intensity of a process differs from the sector average [20, 22]. For example, LCA based solely on I/O analysis have reportedly produced results that are 30% higher in comparison to results obtained through the PCA method, and in the case of nuclear power the deviation can be up to a factor of two [10].

Therefore, it has been frequently suggested to apply a hybrid approach combining LCA and I/O methods, in which the I/O method is used exclusively for assessing processes of secondary importance, such as energy requirements originating from inputs from upstream supply chains of high order [17, 20].

The main advantages of the hybrid-approach are [24]:

- Allows fast approximation of possible outcome
- Data gaps of PCA can be closed by approximations provided by I/O

Hybrid models therefore allow the boundaries of the analysis to be broadened by accounting for all processes. This is particularly important where a system comprises of many processes and process steps. For fossil fuel power plants the results of a detailed PCA and the hybrid-approach will not differ significantly because the emissions over the whole LCA are dominated by emissions during the operation phase, whereas the life cycle stage is balanced well by both approaches [22]. Although hybrid models are now common they have by no means established themselves as LCA-standard. Especially since the existence and continuous development of sufficiently accurate LCA background databases included in commercial and non-commercial LCA-tools and/or databases (e.g. SimaPro, EcoInvent, U.S. Life Cycle Inventory Database) may revive and further diffuse PCA.

5 Results

This section discusses the results of the assessed LCAs, as well as highlighting the most significant stages of GHG release for the technologies under consideration. *The GHG emission estimates presented here reflect the differences, in for instance, assessment methodology (i.e. I/O, PCA, hybrid),* *conversion efficiency, practices in fuel preparation and transport, technology and fuel choice, the fuel mix assumed for electricity requirements related to plant construction and manufacturing of equipment, and the assessment boundary (i.e. what processes are included in the analysis and which ones are not).* Analysing up-and downstream processes and its associated GHG emissions, which arise upstream and downstream of the power plant (i.e. electricity generation stage), is important since otherwise the GHG emissions resulting from electricity generation of the various fuel options are underestimated. For fossil fuel technology options, upstream GHG emission rates can be up to 25% of the direct emissions from the power plant, whereas for most RETs and nuclear power upstream and downstream GHG emissions can account for over 90% of cumulative emissions.

The matrix in Appendix 1 provides an overview of the key parameters affecting the life-cycle GHG emissions for each of the energy technologies (apart from CCS and energy storage), as well as indicating areas in which improvements in GHG emissions are likely to occur in the future. In the following sections, GHG emissions per kWh_e do not take into account emissions arising from electricity transmission and distribution and are therefore considered net or busbar values.

5.1 Fossil

For fossil fuel technologies the majority of life-cycle GHG emissions arise during the operation of the power plant. As discussed in section 3, the recorded variation of direct emissions is a combination of the carbon/heat content of the fuel, the type of technology and its efficiency. GHG emissions arising during downstream activities are typically negligible. However, upstream GHG emissions between coal, gas and oil can be significant but vary mainly due to the different modes and processes involved in extraction, fuel transportation and fuel-preparation.

Table 1 shows an example of the differences that have been recorded in upstream GHG emissions between fuels and for countries in Europe. Here, it is striking that the upstream GHG emissions from coal and oil (heavy) in Western Europe are approximately 15 and 25 times higher than for lignite. The upstream GHG emissions from natural gas and light fuel oil are even higher. As will be illustrated in the following sections direct emissions from fossil fuel power plants may also vary by an order of magnitude, but only when considering future best performers using CCS technology.

		Min (kg CO_2 eq/kg fuel)	**Max** (kg CO_2 eq/kg fuel)
Hard Coal	At producing region	0.04 (south. America)	0.34 (west. Europe)
	Country specific supply mix	0.188 (Poland)	0.322 (Germany)
	Supply mix UCTE	0.270	
Lignite	At mine	0.017	
Oil	Heavy fuel oil (west. Europe)	0.423	
	Light fuel oil (west. Europe)	0.480	
Nat. gas	West. Europe high pressure grid	0.491	

Table 1: GHG emissions from the upstream chains of fossil fuels used in Europe
Source: [17]

5.1.1 Lignite

The vast majority of the cumulative GHG emissions from lignite power plants occur at the power plant, with no significant contributions from construction, decommissioning and waste disposal. However, during the fuel-cycle noteworthy GHG emissions typically occur. Because of the low calorific value of lignite the fuel masses to be burned are large in comparison to hard coal. Consequently most lignite power plants are mine-mouth, which means that the power plant is situated close to the mine thus not requiring energy intensive transport [18], typically by way of conveyor belt. While the upstream chain of lignite power plants does not have a substantial impact on cumulative results, the upstream chain of hard coal power plants can be an important factor, as illustrated in more detail in the next section. Especially the mining and extraction stages of hard coal can release considerable amounts of methane into the atmosphere, therefore contributing significantly to cumulative life cycle GHG emissions (while lignite has already lost most of its methane in the past due to 'out-gassing'). For example, methane emissions from lignite are calculated to be only about 0.6% of cumulative GHG emissions in UCTE (Union for the Coordination of Transmission of Electricity) lignite chains, while mining activity is estimated to range between 0.9% in France and 2.6 % Greece [17]. Therefore, if full LCA emissions are considered (instead of direct emission only) lignite fares well in comparison with hard coal where transport and coal mine methane emissions add considerable to cumulative GHG emissions.

Figure 5 shows the estimated life-cycle GHG emissions from selected energy technologies based on the literature review carried out in this research. Specifically, the graph shows the mean, the standard deviation as well as the minimum and maximum emissions reported for each technology. With respect to lignite power plants significant variations in cumulative GHG emissions have been quoted in the literature, ranging from approximately 800-1700 gCO_2eq/kWh_e[5]. While cumulative GHG emissions from *future* (up to 2020) and *advanced* (2010) technologies have been estimated to be just over 800 gCO_2eq/kWh_e, *presently* operating lignite power plants have emissions between 1100-1700 gCO_2eq/kWh_e. The great variation in the emissions of current lignite power plants indicates the importance of thermal plant efficiency and operating mode, since most GHG emissions occur at the combustion stage. Significant improvements in the cumulative GHG emissions thus need to focus on the factors affecting direct emissions as discussed in section 3.

5.1.2 Coal

In coal-fired power plants, the largest part of life-cycle GHG emissions arises at the power plant. For *presently* operating plants, emissions at the operating stage range between 800-1000 gCO_2eq/kWh_e,

[5] gCO_2eq/kWh_e = grams of carbon dioxide equivalent per kilowatt hour (electricity)

whereas cumulative emissions for the same plants range between approximately 950-1250 gCO_2eq/kWh_e (see Figure 5).

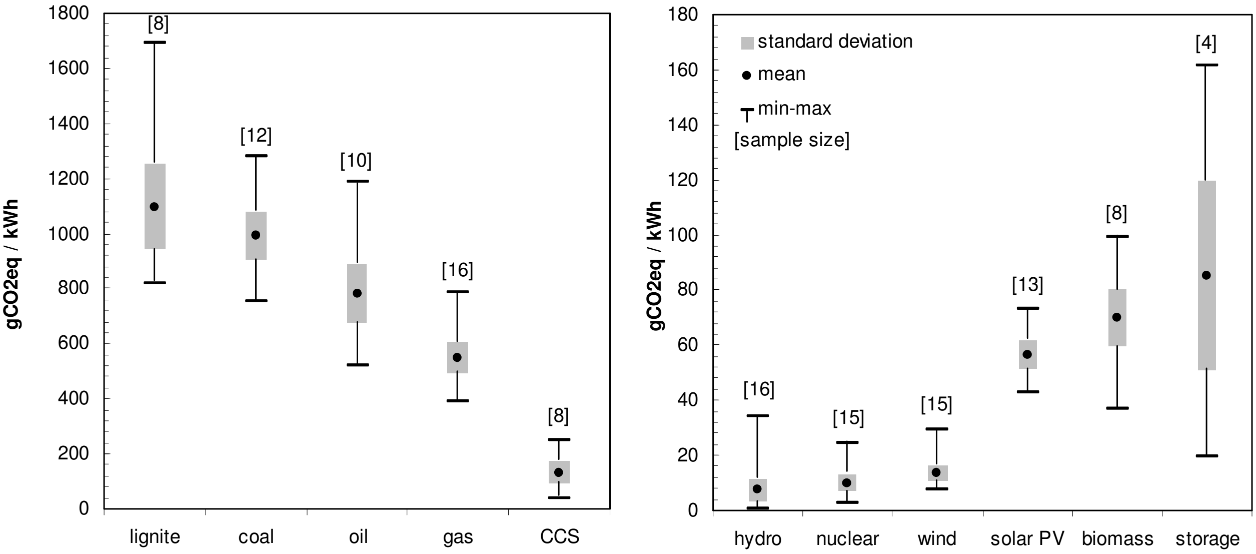

Figure 5: Summary of life-cycle GHG emissions for selected power plants
Source: Lignite [10, 17, 26], coal [10, 17, 22, 26, 27, 28], oil [10, 17, 18, 22, 28], natural gas [10, 12, 17,22, 26, 28, 29, 30], carbon capture & storage (CCS) and energy storage systems [21, 31, 32], nuclear [10, 12, 17, 18, 27, 28, 34, 35], solar PV [17, 26, 28, 36, 37], wind [17, 18, 26, 28, 38, 39, 40, 41], hydro [28, 42, 43, 44], biomass [26, 42, 45

The difference arises at up-and downstream stages, which have been recorded to lie between roughly 50-300 gCO_2eq/kWh_e. While GHG emissions from construction, decommissioning and waste disposal are negligible, emissions relating to coal mining and coal transport can be significant. Dones et al. [17] survey methane emissions to be nearly 7% of cumulative GHG emissions for the UCTE average, while the cumulative upstream GHG emissions from coal in UCTE countries ranges between 8% (Portugal) and 12.5% (Germany). Spadaro et al [10] survey non-direct emissions to be as high as approximately 20% of cumulative GHG emission. The recorded difference in upstream emissions can mainly be attributed to variations in methane emissions from different coal seams. For example, Dones et al [17] record average coalmine methane emissions to range between 0.16g/kg (US open pit) - 13.6g/kg (West Europe) between eight different regions – a difference of two orders of magnitude.

For *future* and *advanced* technologies the total cumulative GHG emissions range roughly between 750-850 gCO_2eq/kWh_e, but require improvements in thermal plant efficiency and methane recovery.

5.1.3 Oil

Most of the GHG life-cycle emissions arise from the operation of the power plant, which range between roughly 700 – 800 gCO_2eq/kWh_e. GHG emissions from power plant construction and decommissioning are negligible, and significant upstream emissions arise mainly at the stages of oil transport, refinery, exploration and extraction, which are in the range of 40-110 gCO_2eq/kWh_e. Dones et al [17] report that on average upstream GHG emissions from oil in UCTE countries are 12% of the cumulative emissions. Cumulative emissions lie roughly between 500-1200 gCO_2eq/kWh_e (see Figure

5). The wide range of GHG emissions does not only depend strongly on technology but also on the different operation of oil fired power plants in European countries (base load vs. peak load).

5.1.4 Natural Gas

The majority of GHG emissions from gas-fired power plants arise during the operation of the power plant and range according to the literature between 360-575 gCO_2eq/kWh_e for present technologies. No significant emissions arise during the construction and decommissioning of the power plant.

However, significant fuel-cycle GHG emissions exist. They are mainly from gas processing, venting wells, pipeline operation (mainly compressors) and system leakage in transportation and handling [22]. Because these factors vary amongst countries, the import structure can be an important factor in determining cumulative emissions. Dones et al [12] report that the leakage rate for transmission of natural gas from the Russian Federation over a distance of 6000km is estimated at 1.4% (with additional leakage in regional and local distribution), whereas energy use in the compressor stations of the pipelines is estimated a further 1.8% of transported gas per 1000km in Europe and 2.7% per 1000km for the Russian Federation. Therefore, the loss rate in the distribution network increases with increases in distance.

In the US, according to the Department of Energy (DOE), nearly 10% of natural gas is lost before reaching the power plant [22] creating significant upstream GHG emissions. Most of this energy loss is due to the compression of a natural gas for transport via pipeline. Transmission operations also lose gas due to leaks from compressor stations, metering and regulating stations, and pneumatic devices. Further losses in the form of fuel combustion and fugitive releases are recorded during processing which prepares natural gas to meet pipeline specifications. A small fraction of the energy loss occurs as the natural gas, consisting primarily of methane, is released directly to the atmosphere from venting wells. While the quantity of atmospheric releases of natural gas (or methane) is often small, it is still significant since the global warming potential of methane is roughly 23 times higher than for carbon dioxide [47].

In Europe, Dones et al [17] estimates that the up-and-down stream emissions from gas-fired generation constitute about 17% of the average UCTE life-cycle GHG emissions in 2000.

In the consulted literature, upstream and downstream GHG emissions from natural gas fired plants lie between 60–130 gCO_2eq/kWh_e for present technologies, with cumulative emissions between 440-780 gCO_2eq/kWh_e. Advanced and future gas-fired power plants are estimated to emit just under 400 gCO_2eq/kWh_e over the full life-cycle with approximately 50 gCO_2eq/kWh_e as non-direct GHG emissions. In order to realise these lower emissions, efforts need to focus on the reduction of gas leakage, improvements of power plant combustion performance and overall plant efficiency [17], as well as pipeline performance.

5.2 Carbon capture & storage (CCS) and energy storage

CCS is defined by the IPCC as a ‘process consisting of the separation of CO_2 from industrial and energy-related sources, transport to a storage location and long-term isolation from the atmosphere’ [31]. Ultimately, the net reduction of emissions depends on the CO_2 capture system (e.g. post- and pre-combustion capture), as well as the transport and the storage options. In its *Special Report on Carbon Dioxide Capture and Storage* (CCS) the IPCC [31] estimates CO_2 (stack) emissions for CCS technology to lie in the range of 92-145 gCO_2/kWh for pulverised coal technology, 65-152 gCO_2/kWh for IGCC and 40-66 gCO_2/kWh CCGT. This is equivalent to a CO_2 emission reduction per kWh in the range of 80-90% depending on technology and fuel. Spath & Mann [32] report higher numbers for CCS mainly due to the fact that supposedly substantial downstream emissions from various energy chains, which cannot be captured by the CCS technology, are included in the analysis. They report 247 gCO_2eq/kWh for a pulverised coal fired power plant and 245gCO_2eq/kWh for a CCGT power plant. While it seems surprising that coal has a similar GHG emission value to gas, Spath and Mann [32] explain this in the higher GHG emission assumptions in the upstream chain for natural gas.

Overall, CCS decreases the net efficiency of a power plant and increases the fuel consumption per kWh delivered to the grid. Dones et al [17] estimates that for CCGT fuel consumption increases by 16-28%, for pulverised coal by 22-38% and coal IGCC by 16-21%, while capital costs increase by 30-50% for IGCC, 70-80% for pulverised coal, and 80-100% for natural gas. Spath & Mann [32] estimate the generating cost for a coal-fired power plant to increase from US$ 0.025 to US$ 0.073 (with 60% of the additional cost necessary for CO_2 capture and compression and the remainder equally shared between the cost of replacement power and the cost of CO_2 transport and storage); and for a new CCGT to increase from US$ 0.045 to US$ 0.075 (with 50% of the additional cost needed for CO_2 capture and compression and the remainder equally shared between the cost of replacement power and the cost of CO_2 transport and storage). The IPCC [31] assumes the cost of electricity production to increase between US$ 0.012-0.024 for CCGT, US$ 0.018-0.034 for pulverised coal, and US$ 0.009-0.022 per kWh for a new IGCC plant. Depending on the value of carbon and a regulatory framework that supports CCS as an abatement technology the additional cost of using this technology may be justified.

Similarly, the use of energy storage in combination with electricity generation increases i) the input of energy required to produce electricity ii) the associated cumulative GHG emissions, as well as iii) the total cost of such a hybrid system. However, cumulative GHG emissions from storage systems when operated in combination with low-carbon technologies, such as nuclear or renewable technologies, can be substantially lower than from fossil fuel derived electricity. Using storage may also be desirable for eliminating the intermittent nature of some renewables thereby being able to provide dispatchable grid services or to provide power at peak power demand to receive higher electricity sales revenues [21].

Therefore, GHG LCA of storage systems can provide a basis for comparison of the cumulative GHG emission between, for instance, intermittent renewables and firm energy sources (ibid.).

Figure 5 summarises the life-cycle GHG emissions based on a study by Denholm and Kulcinski [21] for four energy storage systems using a PCA for most material assessments and an I/O analysis to derive data for certain system aspects where information is not available. Compressed Air Energy Storage (CAES) and Pumped Hydro Storage (PHS) are considered mature technologies and significant improvements in both energy input and efficiency are unlikely in the near future, whereas the Battery Energy Storages (BES) systems (i.e. Vanadium Redox Battery (VRB) and Polysulfide Bromide Battery (PSB)) presented here are still under development and significant cost and efficiency reductions can be expected [21].Presently, BES has higher GHG life-cycle emissions than CAES or PHS with the vast majority of emissions relating to power stack materials and manufacturing, as well as balance-of-plant. The life-cycle GHG emission *per kWh of storage capacity* is reported to be 19 gCO_2eq for CAES, 36 gCO_2eq for PHS and 125 and 161 gCO_2eq for PBF and VRB respectively. It is therefore important to emphasise that, depending on the source of electricity used for energy storage (i.e. high or low carbon intensity per kWh), energy storage can add significantly to the GHG emissions of an electricity supply system.

5.3 Nuclear

Differences in the GHG emissions for nuclear energy chains, amongst others, can be attributed to the enrichment technology used, as well as the nuclear energy technology type (e.g. Pressurised Water Reactor (PWR), Boiling Water Reactor (BWR)). For example, enrichment using diffusion technology rather than centrifuge technology is more energy intensive and depending on GHG emissions relating to the electricity supply mix of the country where enrichment is taking place can significantly impact on the cumulative GHG life-cycle. A typical chain for nuclear would, for example, consist of uranium mining (open pit and underground), milling, conversion, enrichment (diffusion and centrifuge), fuel fabrication, power plant, reprocessing, conditioning of spent fuel, interim storage of radioactive waste, and final repositories [17]. The studies summarised in this section have investigated the GHG life cycle emissions only for Light Water Reactors (LWR) (i.e. PWR and BWR), which is the most widespread and commonly used reactor technology.

For LWR GHG emissions during the operational stage of the reactor, relative to cumulative life-cycle emissions, are of secondary importance – ranging between 0.74 – 1.3 gCO_2eq/kWh_e. Unlike fossil fuel powered technologies the majority of the GHG emissions arise at the upstream stages of the fuel and technology cycle with values roughly ranging between 1.5 –20 gCO_2eq/kWh_e. The notable difference in the upstream emissions is mainly due to the enrichment process, with significantly higher emissions for diffusion technology and lower values for centrifuge technology if the associated electricity consumption is of fossil origin, as well as whether the fuel-cycle is ‘once-through’ or ‘recycled’.

However, it is important to note that centrifuge technologies are presently the technology of choice and are believed to substitute diffusion technology in the future which currently have about 40% of the market output (i.e. enriched uranium) [33]. The GHG emissions associated with downstream activity, such as decommissioning and waste management, range between 0.46-1.4 gCO_2eq/kWh_e. Cumulative emissions for the studies under consideration lie between 2.8-24 gCO_2eq/kWh_e, as shown in Figure 5. Dones et al [17] suggest that in order to reduce emissions from nuclear technologies key areas of improvement would be to:

- Reduce electricity input for the enrichment process (e.g. replacement of diffusion by centrifuges or laser technologies)
- Use electricity based on low or no-carbon fuels
- Extend lifetime and increase burn-up

GHG avoidance at the operating stage of the nuclear power plant is minimal since its contribution to the cumulative GHG emissions is already small.

5.4 Renewable Energy Technologies

In contrast to fossil fuel technologies, the vast majority of GHG emissions from RETs occur upstream of the plant operation – typically for the production and construction of the technology and/or its supporting infrastructure. Although for biomass systems the majority of emissions can arise during the fuel-cycle depending on the choice of biomass fuel. For intermittent technologies the question arises whether or not life cycle analyses should include the GHG emission resulting from required backup services, such as spinning reserve, or not. Principally this is yet not included in the studies provided.

5.4.1 Photovoltaic

Figure 5 summarises the results from various life-cycle studies for photovoltaic systems, which range between 43-73 gCO_2eq/kWh_e. Typically four systems have been assessed: mono-crystalline, poly-crystalline, amorphous and CIGS (Copper Indium Gallium Diselenide). Unlike fossil fuel systems most of the GHG emission occur upstream of the life-cycle with the majority of the emissions arising during the production of the module (between 50-80%). Other significant GHG releases in the upstream relate to the balance-of-plant (BoP) and the inverter. Operation, end-of-life and associated transport activities do not result in meaningful cumulative GHG emissions. Of the four systems, mono-crystalline plants, on average, may emit the least GHGs ranging between 43-62 gCO_2eq/kWh_e. The other PV systems may emit between 50-73 gCO_2eq/kWh_e over the whole GHG life-cycle. Variations in the results can be for a range of factors, such as the quantity and grade of silicon, module efficiency and lifetime, as well as irradiation conditions. Differences in installation, such as integrated and non-integrated systems, as well as facade, flat roof and solar roof tiles, or the efficiency of the peripheral equipments, such as the balance-of-system (BOS), also significantly affect lifecycle GHG emissions in the presented case studies. It is also important to note that the studies summarised here are based on different assumptions of solar radiation (due to different geographies), solar panel orientation and angle. Future improvements in cumulative GHG emissions from PV are likely to arise from improvements in module efficiency, increased lifetime, less silicon mass per module and lower use of electricity for the production process. In this regard it may be important to note that solar PV technology is a relatively fast-improving technology and new LCA studies are frequently being published in order to keep the pace with the advancements (this is also true for other RETs such as wind turbines).

5.4.2 Wind

For wind turbines most of the GHG emissions arise at the turbine production and plant construction, which vary between 72-90% of cumulative emissions. Significant differences lie mainly in the foundation of the power plant. For instance, offshore wind turbines require significantly higher amounts of steel and cement than an on-shore counterpart for construction. For onshore plants however most of the GHG emissions relate to the turbine production (mainly for the tower and the nacelle). GHG emissions not related to construction and production arise during operation & maintenance, decommissioning, transport of materials and turbine, and range between 10-28% of cumulative emissions.

Typically, larger turbines – under similar wind conditions – have lower life-cycle GHG emissions than smaller turbines, whereas offshore turbines have higher emissions than onshore turbines given equal capacity factors (or wind conditions), due to the high level of emissions associated with the foundation, connection and erection for off-shore turbines [17]

LCA GHG emissions from wind turbines are very site-specific and sensitive to wind velocity conditions, because of the cubic relationship of wind velocity to power output. Since wind regimes vary significantly with geography different capacity factors used in the studies add to the variation that can be observed in the results, which lie between 8-30 gCO_2eq/kWh_e for onshore, and 9-19 gCO_2eq/kWh_e for off-shore turbines (see Figure 5). Since wind turbine technology is rapidly improving the accuracy of LCA results have only a limited lifespan since these improvements can significantly alter the outcome of such a study. Improving the lifetime of a wind turbine, for example, can drastically reduce the LCA values (which is also true about different LCA studies assuming different lifetimes at the inception of their study).

5.4.3 Hydro

In the majority of the analysed cases most of the GHG emissions typically arise during the production and construction of the hydroelectric power plant (especially for reservoir dams). In the illustrated cases emissions for construction and production roughly lie between 2-9 gCO_2eq/kWh_e. However, in some cases hydro power plants that use reservoirs can emit significant quantities of GHGs that easily surpass all other GHG emissions in the energy chain, due to land-clearance prior to construction but especially due to flooding of biomass and soil. For example, flooded biomass decays aerobically – producing carbon dioxide – and anaerobically – producing both carbon dioxide and methane [21]. The amount of GHG release depends on reservoir size, type and amount of flooded vegetation cover, soil type, water depth, and climate. As reported by Bauer [44] for European examples, these releases can vary considerably depending on the specific GHG releasing characteristics - as discussed above - and lie between 0.35 gCO_2eq/kWh_e for reservoirs in the alpine region and on average 30 gCO_2eq/kWh_e for reservoirs in Finland, although peat soils have reportedly higher GHG releases[6].

Overall, the life cycle GHG emissions for the assessed cases range between approximately 1-34 $gCO_2eq/kWh_{e,}$, as shown in Figure 5, depending on the type of plant (run-off or reservoir), its size and usage (e.g. pumped hydro), as well as the electricity mix (and hence emissions) used for its operation. However, it is important to emphasise that the emission results from pumped storage, run-of-river and reservoir do vary significantly. In fact, the life-cycle GHG emissions from pumped hydro can be significantly larger than the values quoted here when the electricity used to pump/store water is generated from fossil fuel based technologies (see also section 5.2)

5.4.4 Biomass

Life-cycle GHG emissions from biomass systems mainly depend on the energy intensity of the fuel-cycle, the bio-fuel properties, as well as the plant technology and its specific thermal conversion efficiency. The range of life-cycle GHG emissions for the studies given in Figure 5 lie between approximately 35-99 gCO_2eq/kWh_e. The majority of emissions arise at the fuel-cycle stage, while GHG emissions during the other stages of the life-cycle are negligible. Biogenic GHG emissions (emissions arising from the combustion of biofuel) are not included in the Figure since they are believed to be carbon neutral. Generally the use of biomass at the electricity generation stage is defined as a 'carbon-neutral' because the CO_2 released during combustion is absorbed during (fuel-) plant growth. Life-cycle emissions for biomass systems vary substantially depending on the combustion efficiency, power rate and the type of feed (e.g. chips vs. logs vs. pellets vs. gas).

More recently publications on GHG emissions from the growth of different energy fuels have emerged, but for consistency and comparability only wood-based fuels have been quoted here.

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[6] Dones et al [17] report of two additional research studies from Canada and Brazil. Canadian research concluded that reservoirs in tropical regions (where biodegration is faster) emit approximately 5 and 20 times more GHG than in boreal and temperate regions. This translates into average GHG emission factors of 10-60 gCO2eq/kWhe for boreal and temperate reservoirs and 200-3000 gCO2eq/kWhe for tropical reservoirs. Similar results were presented from the Brazilian researchers who found that using the average capacity factor for seven Brazilian hydroelectric plants results in an interval of direct reservoir emissions of 12–2077 gCO2eq/kWhe averaging at approximately 340 gCO2eq/kWhe

6. Discussion and Concluding Remarks

The life-cycle analyses presented here indicate for some cases the existence of significant upstream emissions (e.g. up to 25%) that may arise outside the legislative boundaries of a national GHG mitigation programme / regulation. Consequently, electricity generation and use in one country may result in significant GHG releases in another.

For example, increasing demand for gas-fired power plants in the UK (as a result of market liberalisation) has substantially lowered GHG intensity in the UK power sector. As an Annex B party to the Kyoto Protocol this so-called 'dash-for-gas' has significantly aided the UK's efforts in achieving its Kyoto obligations (although this has happened for different reasons). However, with an (expected) increasing share of natural gas to be imported to the UK – due to dwindling North Sea Gas reserves – from countries outside Annex B (e.g. Middle East, North Africa) [48, 49] upstream emissions from natural gas sourcing, processing and transport will be arising outside Britain's GHG accounting[7]. For now, gas exporters such as Middle Eastern countries have no GHG emissions constraints. This so-called 'leakage' effect would therefore lessen the GHG emission improvements made in the UK since leakage between Annex B and non-Annex B countries is presently not counted against the emission reduction targets of Annex-B countries.

Since upstream GHG emissions can be up to 25% of cumulative emissions it would be desirable to develop a system or compliance mechanism that can capture/account for upstream (and downstream) releases of GHG across a range of spatial scales in order to identify (un-)intended leakages – not only to make climate policy more effective and holistic but also to level the playing-field for technologies that do not have significant indirect emissions. In the case of fossil fuels, indirect emissions can be as high as 300 gCO_2eq/kWh_e, while for renewable and nuclear energy technologies cumulative indirect GHG releases are typically lower than this number by an order of magnitude.

Globally the power sector is responsible for a large share of present-day GHG emissions. In 2002, power and heat generation contributed to roughly 40% of global GHG emissions (which are likely to be higher if the life-cycle emissions were considered) while transport, for example, contributed to about 20% [51]. The *Reference Scenario*[8] of the IEA's 2006 World Energy Outlook projects that power generation will contribute to half of the increase in global carbon dioxide emissions between 2004 and 2030 [52]. Therefore, mitigation strategies that can effectively reduce GHG emissions from

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[7] Liquefied Natural Gas (LNG) imports - although not analysed here - requires 7-10% of gas delivered for liquefaction increasing the upstream chain GHG emissions (comparable to several thousand km pipeline transmission).

[8] The *Reference Scenario* takes account of those government policies and measures that were enacted or adopted by mid-2006, though many of them have not yet been fully implemented. Possible, potential or even likely future policy actions are not considered.

electricity generation may play a pivotal role in meeting countries' obligations under the Kyoto Protocol and the UNFCCC.

While there are technology winners with regard to life-cycle GHG emissions in electricity generation - this literature review has shown that RETs and nuclear have lower life-cycle GHG emissions than fossil fuel technologies - it is important to realise that RETs and nuclear energy may not be available at sufficient quantities at competitive prices or not acceptable on social or political grounds to begin dominating power supply in the short- to medium-term. In fact, the social, political, economic and infrastructural reality of meeting growing energy needs is likely to require the pursuit of a combination (if not all) of GHG mitigation policies to help reduce the GHG intensity from power sector activity.

The following discussion focuses on carbon mitigation options, with a view of identifying policies that are likely to improve the carbon intensity in the power sector on a global scale against the backdrop of a rapidly increasing electricity demand.

Broadly speaking five carbon-mitigation options exist for the power sector as identified – amongst others – by Sims et al [46]:

1. *More efficient conversion of fossil fuels*

   In the cases presented for coal-fired power plants (see section 5.1.2), for example, thermal plant efficiency varies between roughly 30-50% with nearly twice the GHG emissions for low efficiency plants compared to most efficient plants. This shows that coal-based technology has a large GHG emissions reduction potential. However, in the short- to medium-term this requires market and regulatory frameworks that encourage investments in the latest technologies that will improve the efficiency of coal-fired electricity generation and thus reduce specific CO_2 emissions [53]. China, for example, the world's biggest user of coal for electricity generation could use approximately 20% less coal if its power plants were as efficient as the average power plant in Japan today [54]. Similarly, Russia the world's biggest user of natural gas for electricity generation could use a third less gas, if its power plants had the same average efficiency as Western European gas-fired power plants (ibid.). Since coal and gas together had a combined share of 60% in global electricity generation in 2004, which according to the IEA's 2006 World Energy Outlook is projected to increase to 67%, policies need to create conditions that make the adoption of highly efficient fossil fuel power plants lucrative to investors and markets [52].

   Figure 5 shows that the variation in life-cycle GHG emissions for each fossil fuel technology is significant - the difference between the best and worst performer is typically at least double, and the difference between the best performer and the mean typically at least 30% lower. Since the majority of GHG emissions is at the electricity generation stage large savings can be made from applying best performance technologies, as suggested by the above examples.

2. *Switching to low-carbon fossil fuels and suppressing emissions generated*

The summary results given in Figure 5 show that switching from coal (especially lignite) and oil towards using best available technologies in gas generating plants can lead to GHG emissions savings (e.g. average life-cycle GHG emissions from gas fired plants are approximately ½ of lignite/coal fired power plants) . However, it needs to be recognised that switching from one technology/fuel to another represents only a technical option. The underlying economic reality will determine whether this option is used (e.g. the switch from coal/lignite to gas will only be done when the price is right). Furthermore, switching from coal/lignite to gas on a substantial scale can lead to upward pressure on the gas price potentially eroding the economic benefit of gas. In addition, switching from one fuel to another is likely to require further investment to develop a supportive infrastructure that facilitates fuel switching. For example, switching from coal to gas may require additional gas pipelines and LNG/LPG terminals to accommodate the expansion of gas fired power plants. The additional cost to develop such an infrastructure may also render fuel switching uneconomic - unless regulatory or investment assistance facilitates the use of low-carbon fossil fuels. .

3. *Increasing the use of nuclear power*

From a GHG emission perspective nuclear power plants (i.e. LWR) are very attractive since they have a huge GHG life-cycle reduction potential when displacing fossil fuel fired power plants, as well as the ability to provide energy services similar to most fossil fuel based energy technologies[9]. Figure 5 shows that on average LWRs have the second lowest life-cycle GHG emissions of all assessed technologies

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[9] While nuclear power plants are typically base load power plants, and some are being used in load-following mode (e.g. France, Japan), they are not appropriate as peaking/balancing power plants.

However, in many countries nuclear power is socially and/or politically not acceptable which clearly limits its global GHG reduction potential. In countries where nuclear power is acceptable, governments have to play a stronger role in facilitating private investment, especially in liberalised markets, if nuclear power is to play a more important role in the future [52]. For example, in its *Alternative Scenario*[10] the IEA projects that nuclear power is going to provide approximately 14 % of electricity in 2030 (down from 16% in 2004) [52] - indicating the limitation of nuclear power to reduce GHG emission intensity from the power sector in the medium-term.

4. *Increasing the use of renewable sources of energy*

Figure 5 shows that greater use of RETs can significantly reduce the carbon intensity of electricity generation in power sectors that are dominated by fossil fuel power plants.

However, renewables are unlikely to meet the present and forecasted energy demands at reasonable cost (as suggested in most literature), nor are intermittent RETs able to provide necessary network services that fossil fuel technologies can (e.g. frequency control, regulating and balancing power). The significant expansion of intermittent or distributed renewables may also require advances in grid management and network upgrading, as well as energy storage or other forms of back-up capacity, which can impose additional costs and emissions on their operation. Although, the combined life-cycle GHG emissions from the hybrid/joint operation of RETs and energy storage, which can improve the availability of intermittent RETs, can still be lower compared to CCS this depends crucially on the carbon intensity of the electricity used for providing energy storage.

In its most optimistic medium-term projection, the IEA projects that the electricity share from renewables is to increase from 18% in 2004 to 26% in 2030 - of which the majority of the marginal increase is hydro [52]. The global potential for RETs in improving the emissions intensity from RETs therefore seems limited in the medium-term.

5. *Decarbonisation of fuels and flue gases, and CCS*

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[10] The *Alternative Policy Scenario* analyses how the global energy market could evolve if countries were to adopt all of the policies they are currently considering related to energy security and energy-related CO2 emissions.

Section 5.2 indicates that the adoption of CCS technologies could lead to substantial reductions in life-cycle GHG emissions (e.g. at least 2/3 and ½ for coal and gas respectively) but at yet high cost penalties. While in the future, technology learning is likely to bring down the present cost penalty of CCS, in the short- to medium term substantial financial incentives and more RD&D will be needed [54]. Higher market prices of carbon certificates may also improve the economics of CCS. However, Figure 5 shows that, although CCS can lead to a reduction in the life-cycle GHG emissions of fossil fuels, they are still higher than for nuclear power plants and RETs.

Nonetheless, since - on a global level - RETs and nuclear are unlikely to be able to provide electricity at the scale needed to meet growing electricity needs, CCS may well become a sought-after intermediate technological solution. Especially in view of the fact that the projected marginal demand increase for heat and power by 2030 is expected to be met by 75% from fossil fuels [52]. Given the medium-term global energy needs the application of CCS bears significant potential in limiting/reducing GHG emissions from the power sector.

All the above options can aid countries in reducing the GHG emissions intensity from power production at a national level from an energy supply perspective. For example, in the *Alternative Policy Scenario* of the 2006 World Energy Outlook, the IEA [52] projects CO_2 intensity improvements of electricity generation, such as the increased use of nuclear power and renewable energy technologies, to contribute to 22% of the avoided CO_2 emissions (in comparison to the *Reference Scenario*) by 2030. Improved efficiency and fuel switching in the power sector would lead to global savings in CO_2 emissions of 13% under the same conditions.

However, it is also important to note that many demand side management (DSM) options can reduce electricity demand (and hence emissions) more effectively than altering energy supply patterns. According to the IEA's *Alternative Policy Scenario* demand side policies that encourage more efficient use of electricity, such as in lighting, air conditioning, electrical appliances and industrial motors, contribute to roughly 30% of the avoided CO_2 emissions in comparison to the *Reference Scenario* by 2030 - nearly as much as the combined GHG mitigation potential from the power sector supply side.

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Appendix 1: Specific parameters affecting LCA results

	Fossil Fuels	Hydropower	Biomass	Nuclear (LWR)	Wind	Solar PV
Key Parameters affecting results	- Fuel characteristics (e.g. carbon content and calorific value) - Type of mine and location - Fuel extraction practices (e.g. affect transport and methane release) - Energy carrier transmission/transport losses (e.g. pipeline) - Conversion efficiency - Fuel mix for electricity needs associated with fuel supply and plant construction / decommissioning - Installation rate and efficiency of emission control devices -Lifetime and load factor	- Type of plant (e.g. run-of-river, reservoir) -Size, depth and location of reservoir affect CH_4 release - Energy use for building dam - Lifetime	-Feedstock properties (e.g. moisture content, heating value) and eventual pre-treatment - Processing of feedstock (e.g., gasification and following transport to power unit) - Energy use for feedstock requirements (growth, harvesting, and transport) - Plant technology - Plant conversion efficiency - Lifetime	- Energy use during fuel extraction, conversion, enrichment and construction / decommissioning - Fuel enrichment by gas diffusion or centrifuge (i.e. diffusion requires more energy by an order of magnitude) - Emissions from the enrichment step since they depend on country-specific fuel mixes and/or plant-specific power supply - Fuel reprocessing, open/closed cycles - Lifetime	- Tower and nacelle (onshore) - System foundation and tower (off-shore) - Electricity mix and construction regulations - Wind conditions (i.e. capacity factor or full load hours per year) - Lifetime	- Quantity and grade of silicon used for manufacture - Type of technology - Type of installation (e.g. slanted and flat rooftop, façade) - Fuel mix for electricity requirements throughout the entire production chain. - Module efficiency and assumed lifetime - Location and irradiation conditions - BOS materials and efficiency - Lifetime - Allocation of resources/emissions assumed in the LCA for high (electronic and/or solar) grade silicon production for PV manufacturing
Likely areas for improvements	- Increased methane recovery in underground mining - Improvements in power plant abatement technology - Improving the thermal efficiency of power plant - Reduction of natural gas leakage - Improvements of power plant burner performance - Improvements in pipeline performance	- Improvements in overall plant efficiency - Improved understanding of GHG emissions from reservoirs - hydro management	- Improvements in plant technology and efficiency - Improvement in feedstock properties	- Reductions of electricity consumption in enrichment by replacement of diffusion by centrifuges or laser technologies - Switching from high to low carbon electricity sources can significantly reduce the GHG emissions at the enrichment phase, especially for energy intensive diffusion technology. - Power plant improvements particularly extended lifetime and increased burn-up	- Improved off-shore foundations / towers (e.g. mono-pylon, tripod etc.), as well as light-weight material improvements may improve GHG emissions in the construction phase but requires additional research. - Improved efficiency & size	- Higher cell and module efficiency and lifetime - Lower specific use of Si Mass and lower Si losses during production - Lower electricity consumption throughout the entire production chain

Source: based on 10, 17, 18, 37

A Commentary on "The Greenhouse-gas footprint of natural gas in shale **formations" by R.W. Howarth, R. Santoro, and Anthony Ingraffea**

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Abstract

Natural gas is widely considered to be an environmentally cleaner fuel than coal because it does not produce detrimental by-products such as sulfur, mercury, ash and particulates and because it provides twice the energy per unit of weight with half the carbon footprint during combustion. These points are not in dispute. However, in their recent publication in Climatic Change Letters, Howarth et al. (2011) report that their life-cycle evaluation of shale gas drilling suggests that shale gas has a larger GHG footprint than coal and that this larger footprint "undercuts the logic of its use as a bridging fuel over the coming decades". We argue here that their analysis is seriously flawed in that they significantly overestimate the fugitive emissions associated with unconventional gas extraction, undervalue the impact of "green technologies" to reduce those emissions to a level approaching that of conventional gas, base their comparison between gas and coal on the wrong metric, and assume an inappropriate time interval over which to compute the relative climate impact of gas vs coal. We assert that a more appropriate set of assumptions indicates that natural gas has a climate impact that is 1/3 that of coal when the two are compared on the basis of electricity generation and over a time scale of 100 years.

Keywords: Unconventional Gas, Climate Change, Methane Emissions, Greenhouse Gas Footprint Coal vs Gas, Electric Power Generation

Natural gas is widely considered to be an environmentally cleaner fuel than coal because it does not produce detrimental by-products such as sulfur, mercury, ash and particulates and because it provides twice the energy per unit of weight with half the carbon footprint during combustion. These points are not in dispute.

However, in their recent letter to Climatic Change, Howarth et al. (2011) report that their life-cycle evaluation of shale gas drilling suggests that shale gas has a larger GHG footprint than coal. They conclude that:

- During the drilling, fracturing, and delivery processes, 3.6-7.9% of the methane from a shale gas well ends up, unburned, in the atmosphere. They claim that this is at least 30% and perhaps more than twice the methane emissions from a conventional gas well.

- The greenhouse gas footprint for shale gas is greater than that for conventional gas or oil when viewed on any time horizon. In fact, they state that compared with the methane emissions from coal, it is 20-100 % greater on the 20-year horizon and is comparable over 100 years.

They close with the assertion that: "The large GHG footprint of shale gas undercuts the logic of its use as a bridging fuel over the coming decades, if the goal is to reduce global warming."

We argue here that the assumptions used by Howarth et al. are inappropriate and that their data, which the authors themselves characterize as "limited", do not support their conclusions.

In particular, we believe Howarth et al.'s arguments fail on four critical points:

1. Howarth et al.'s high end estimate of methane leakage from well drilling to gas delivery exceeds a reasonable estimate by about a factor of three and they document nothing that indicates that shale wells vent significantly more gas than conventional wells.

   The data they cite to support their contention that fugitive methane emissions from unconventional gas production is significantly greater than that from conventional gas production are actually estimates of gas emissions that were captured for sale. The authors assume that this kind of capture (or even flaring) is rare, and that the gas captured in the references they cite is normally vented directly into the atmosphere. There is nothing in their sources to support this assumption.

   The largest leakage rate they cite (for the Haynesville shale) assumes, in addition, that flow tests and initial production rates provide a measure of the rate of gas release during well completion and drill out. In other words they assume that initial production statistics can be extrapolated to the gas venting rates during the earlier periods of well completion and drill out. This is incompatible with the physics of shale gas production, the safety of drilling operations, and the fate of the gas that is actually indicated in their references.

   While their low-end estimate of total leakages from well drilling through delivery is consistent with the EPA (2011) methane leakage rate of ~2.2% of production, and consistent with previous estimates in the peer reviewed studies, their high end estimate of 7.9% is unreasonably large and misleading.

   We discuss these issues at length below.

2. Even though the authors admit that technical solutions exist to substantially reduce any leakage, many of which are rapidly being or are already adopted by industry (EPA, 2007, 2009), they seem to dismiss the importance of such technical improvements on estimates of GHG footprint from shale gas. While the low end estimates they provide incorporate the potential impact of technical advances in reducing emissions from the sources common to both conventional and unconventional gas, they do not include the potential impact of "green technologies" on reducing losses from shale gas production. Yet their own references document that the methane loss rate during completion of unconventional gas wells by modern techniques is, or could be, ~0.1%, not the 1.6% they use for both their high end and low end estimates. Downplaying these ongoing efforts and the opportunity to further reduce fugitive gas emissions in the natural gas industry, while at the same time citing technical improvements in the coal industry, gives a slanted assessment which minimizes the positive greenhouse potential of natural gas.

3. Howarth et al. justify the 20-year time horizon for their GHG comparison by simply stating that "we agree with Nisbet et al. (2000) that the 20-year horizon is critical, given the need to reduce global warming in coming decades". But the point Nisbet et al. make in their meeting abstract is that "adoption of 20-year GWPs would substantially increase incentives for reducing methane from tropical deforestation and biomass burning". Their concern is that the 100-year timeframe would not discourage such methane emissions enough. Everyone would agree that discouraging methane as well as CO_2 emissions is desirable, but the Nisbet et al. abstract offers no support whatever for the adoption of a 20-year GWP timeframe when considering replacing CO_2 emissions with CH_4 emission by swapping coal for gas, and we strongly disagree that the 20 year horizon is the appropriate choice in this context. As Pierrehumbert (2011) explains, "Over the long term, CO_2 accumulates in the atmosphere, like mercury in the body of a fish, whereas methane does not. For this reason, it is the CO_2 emissions, and the CO_2 emissions alone, that determine the climate that humanity will need to live with." Methane's short (~7 year) half life in the atmosphere means that even if we put a lot into the atmosphere now it will be gone in a few decades. Given this situation, the best strategy is to substitute methane for CO_2 emissions. One could argue (although Howarth et al do not) that the 20-year horizon is "critical" because of concern over triggering an irreversible tipping point such as glacial meltdown. However, if substituting gas for coal reduces (or could reduce) the GHG impact on a 20-year horizon as well as on a 100-year horizon, as we argue below is the case, substitution of gas for coal minimizes the tipping point risk as well. Most workers choose the 100 year timeframe. Hayhoe et al. (2002) adopt the 100 year timeframe, for example, and their more sophisticated analysis remains, in our opinion, more credible than that of Howarth et al on the issue of gas versus coal.

4. Howarth et al. choose the wrong end use for comparing GHG footprints. Coal is used almost entirely to generate electricity, so comparison on the basis of heat content is irrelevant. Gas that is substituted for coal will of necessity be used to generate electricity since that is coal's overwhelming use. The appropriate comparison of gas

to coal is in terms of electricity generation. The "bridge" is from coal-generated electricity to a low-carbon future source of electricity such as renewables or nuclear (EIA AEO 2011). Howarth et al. treat the end use of electricity almost as a footnote, but it is not. They admit in their electronic supplemental material that, if the final use is considered, "the ability to increase efficiency is probably greater for natural gas than for coal (Hayhoe et al., 2002), and this suggests an additional penalty for using coal over natural gas for the generation of electricity not included in our analysis". They purport to address the electrical comparison in an electronic supplement table, however they do so there on the basis of a 20 year GWP and they minimize the efficiency differential between gas and coal by citing a broad range for each rather than emphasizing the likelihood that efficient gas plants will replace inefficient coal plants. Had they used a 100 year GWP and their low-end 3.6% methane leakage rate, shale gas would have about half the impact of surface coal when used to generate electricity (assuming an electricity conversion efficiency of 60% for gas and their high 37% conversion efficiency for coal). The electric industry has a large stock of old, inefficient coal-fired electric generating plants that could be considered for replacement by natural gas (EIA AEO-2011, Table 1). The much lower construction costs associated with gas power plants (e.g. Kaplan, 2008) means modern gas technology will likely replace this old coal technology as it is retired. If total (well drilling to delivery) leakage is limited to less than 2% (which may be the current situation and, in any case, seems well within the capabilities of modern technology; EPA, 2007, 2009), switching from coal to natural gas can dramatically reduce the greenhouse impact of electricity generation. Minimizing this point by stressing extreme rather than likely scenarios is perhaps the most misleading aspect of the Howarth et al. analysis.

Figure 1 depicts what we suggest is a more appropriate comparison of the likely impact on greenhouse gas emissions when natural gas replaces coal in older coal-burning electric power plants. In our analysis, we assume 60% efficiency for natural gas generation of electricity, 30% efficiency for coal generation of electricity in older plants, and a total methane leakage rate of 2.2%. Relatively low-cost 60% efficient generators using natural gas are commonly available (Siemens). When both fuels are used to produce electricity (MJe), the greenhouse impact of natural gas is only as bad as coal if a very high methane leakage rate of 7.9% and a short global warming impact period of 20 years are selected. By basing their comparison on the heat content of the fuels, gas becomes twice as bad as coal. Only thus can Howarth et al. conclude that gas could be as bad or twice as bad as coal from a greenhouse perspective. Assuming more realistic estimates of gas leakage rates and using the more appropriate 100 year global warming potential factor (of 33 grams of GHG-equivalent CO_2 per gram of methane released to the atmosphere), Figure 1 shows that gas has a much smaller global warming impact than coal. For leakage rates less than 2%, the impact of natural gas approaches 1/3rd that of coal. For the 100y GWP of 33, gas exceeds the global warming impact of deep coal only when its leakage rate exceeds 18.2% of production, and exceeds the global warming impact of surface coal only when its leakage exceeds 17.1% of production. These natural gas leakage rates are well beyond any known estimates.

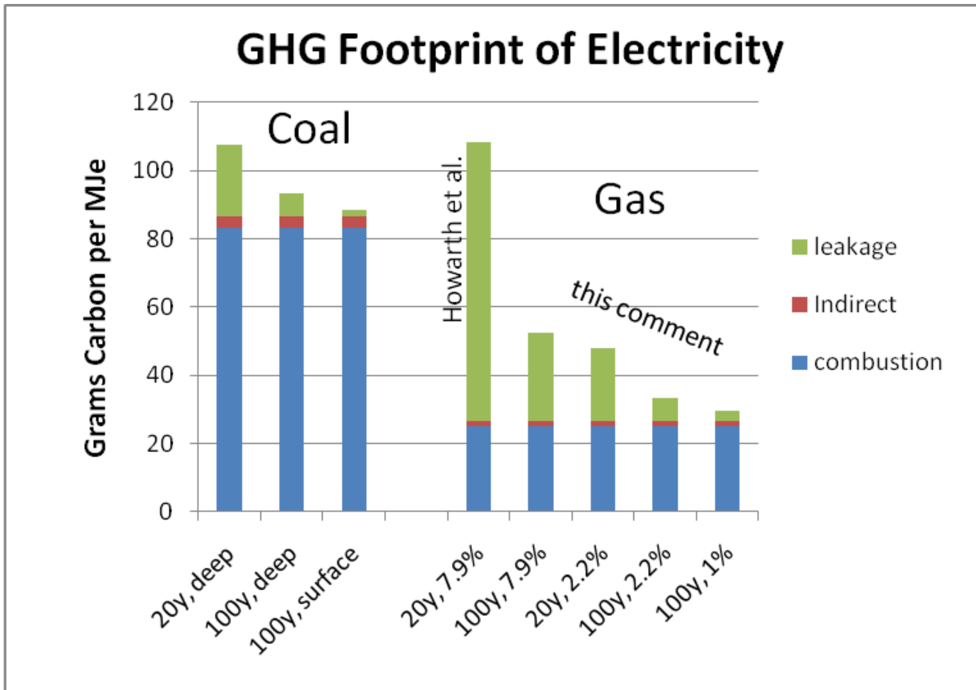

Figure 1. Comparison of the greenhouse impact of burning natural gas to coal when the fuels are used to produce electricity expressed as the grams of GHG-equivalent CO_2 carbon per megajoule of electricity generated. The conversion efficiency to electricity of coal and gas are assumed to be 30 and 60% respectively. As in Howarth et al. (2011) we use 20 and 100 year GWP factors of 105 and 33 grams of GHG-equivalent CO_2 per gram of methane released, and assume deep and shallow coal mining releases 8.4 m^3 and 2.3 m^3methane per ton, respectively.

Methane venting during well completion and drill out of unconventional gas wells

A critical part of Howarth et al.'s paper is the contention that an unconventional gas well vents 1.9% of its lifetime gas production during well completion. (Unconventional gas wells include those producing from tight sands, shales, and coal bed methane wells - the Howarth et al. figures assume that emissions from these are all similar.) This is dramatically more than the 0.01% they cite as vented by a conventional gas well. Their 1.9% number is central to their claim that unconventional gas wells differ from conventional wells, and is a large component in their high-end leakage rates, which are themselves central to their charge that the global warming impact of gas could be twice as bad as coal on a heat content basis.

We agree with Howarth et al. that their data is weak, that their analysis relies heavily on powerpoint presentations rather than values published in reviewed literature, and that there is an obvious need for better estimates. However, given the lack of quality data, we feel that the authors have a responsibility to make explicit the nature and limitations of such sources, and to be especially clear on the assumptions made in their interpretation of such data. We feel that was not done in this case, and offer the following to put their estimates in context.

There are fundamental problems with key numbers that they use in their Table 1 to support their 1.9% contention:

(1) The numbers purported to represent fugitive emissions for the Haynesville shale cannot be found in the references they cite. That the daily methane loss estimates shown in their Table 1 are close to the IP values cited in their references suggests that the authors assume that the latter is somehow an estimate of the former. As argued below, this is incompatible with (a) the basic physics of gas production, (b) the economic incentives of gas production, and (c) the only early production data related to shale gas that can be found amongst any of their references.

(2) The only discussion of methane losses during well completion are found in the citations for tight gas sands, and those values are presented to illustrate how currently used technologies can capture most (up to 99%; Backen, 2008) of those “losses” for sale.

(3) Their estimate of methane loss from drill out is based on two numbers from the Piceance Basin reported in a powerpoint slide presented to an EPA Gas STAR conference (EPA, 2007). They assume that 10 million cubic feet of gas is typically vented during well drill out rather than being captured or flared, although their source makes no such claim. For reasons discussed below, gas production is rare during drill out and if significant gas were produced during drill out it would not be emitted into the atmosphere for safety reasons.

(4) The magnitude of the releases they suggest are in some cases implausible to a degree that reveals a fundamental misunderstanding of well completion and well pad operating procedures, safety, and economic factors.

The Haynesville data are the most problematic in their Table 1, and their high purported methane releases to the atmosphere are erroneous and skew the average for the suite of locations listed.

The value shown in their Table 1 for methane emitted during flowback in the Haynesville does not exist in any of their citations. The reference linked to this number (Eckhardt et al, 2009) is an online industry scout report on various values of flow tests and initial production (IP). To the extent that this reference deals with the fate of the gas associated with those estimates it indicates that the production was captured and sold. The estimate for IP for the Haynesville is based on another informal, unvetted, web posting by a gas producer that is no longer available. However that estimate of IP is consistent with the values cited in Eckhardt et al. and the known characteristics of Haynesville wells. The fact their daily rate of “lost” emissions for the Haynesville is virtually identical to the IP value indicates that the authors believe or assume that: (a) a well produces gas during completion at a rate that is equal to the highest rate reported for the well (the IP rate), and (b) that this gas is vented directly to the atmosphere. They provide no documentation for either of these beliefs/assumptions, which are on multiple grounds illogical.

Flowback gas recoveries cannot exceed initial production recoveries, although Howarth et al. suggest this to be the case for all the areas listed in their Table 1. The problem is this: High gas flow rates are not possible when the well is substantially full of water as it usually is during the flowback period. Gas cannot move up a well filled with water other than in isolated packets, and it can flow optimally only when enough water is removed for the gas to have a connected pathway all the way up the well. Unless otherwise explicitly noted, initial production figures are published to show the highest recorded production rate for each well. They are a benchmark that characterizes what optimal production rate can be achieved by a well (and for which there is every incentive for producers to exaggerate in order to attract investors: http://www.oilempire.us/shalegas.html). The initial production tests cannot be run until after any substantial water has been removed from the well because substantial water impedes the outflow of gas.

Consider what happens in completing a well and bringing gas into production: The well is drilled, logged, and then hydrofractured. When the hydrofracturing is finished, the wellbore and producing formations are full of water. Drill out of the plugs which divide the well into hydrofracture intervals occurs at this stage. Because the well is filled with water, only water is typically produced from the well, and only gas dissolved in this water is brought to the surface, at least initially. Generally this condition persists during the full drill out period, but sometimes gas enters the well during drill out and must be dealt with at this stage. When the drill out is under water-filled-wellbore conditions, the gas leakage rate is comparatively small because, compared to a freely venting gas well, very little gas can be brought to the surface dissolved in water. The water produced at this stage is usually (and could always be) put into a capped tank where the gas exsolves from the water and is flared or captured. When the drill out occurs with substantial gas in the well, more and perhaps very much more gas can be produced, but for safety and economic reasons (see below) it is not vented but captured and either flared of diverted to sales through a pipeline. After drill out is completed, the operator begins to flow water from the well and the flowback stage begins. Normally no (or very minimal dissolved gas) is produced initially, but after a period ranging from hours to multiple days, the well starts to produce slugs of gas, and shortly thereafter enough gas that the well effluent can be diverted to a separator. The gas flow from the separator is generally either flared or put into a pipeline for sale. The first well on a pad may be flared (the methane is not released), but after this the gas is diverted to a pipeline and delivered to sales once enough gas pressure is obtained (or a skid-mounted compressor utilized).

Figure 2 below shows gas well production curves for the Haynesville that include the pre-IP production. It shows clearly that production rates during the pre-production period are much lower than the maximum production rates of the wells (which are generally less than their IP rates). Production of gas is essentially non-existent in the early flow-back period. Significant gas flow starts only when enough frac water has been removed to let the gas begin to flow. The duration of the flowback period is poorly defined and there is no firm correlation between how a well will perform and the volume of gas that is produced during the flowback period. Gas production rates peak days to months later when frac water has been recovered from every producing frac stage and the well is operating optimally. From this maximum the production steadily declines. Most production curves shown for unconventional gas production do not show the initial start up of gas production but begin when the well is considered to be in production.

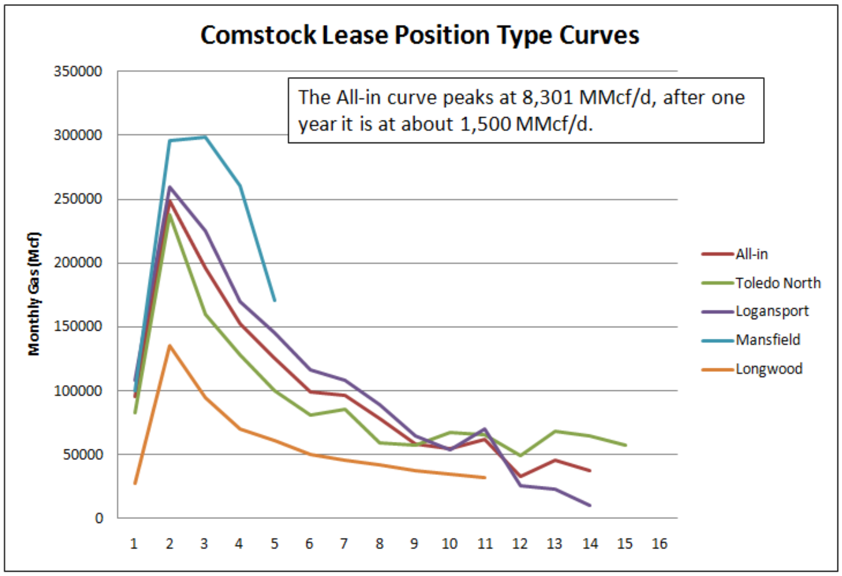

Figure 2. Production curves for Haynesville shale gas production. DI ESP (2010). The horizontal axis is time in months.

A scout report, such as the one cited by Howarth et al. for their initial Haynesville production numbers, rarely indicates what the operator actually does with their gas during the initial testing of a well. Initial production figures therefore generally can't be used to estimate methane emissions because these reports are intended to convey how the well produces, not what the operator does with the production. The only entry in the source document Howarth et al. reference that gives any information related to emissions suggests that the gas flow noted was captured: "*The 1 Moseley was reported producing to sales at the daily rate of 14 million cu ft of gas equivalent through perforations at 12,800-15,260 ft while the operator was still cleaning up frac load*." (Eckhardt et al., 2009). In other words, at the time the gas flow rate was measured, the flowback was still ongoing and gas was *producing to sales*. This is the exact opposite of the venting of the gas to the atmosphere that Howarth et al. suggest.

The only sources which explicitly provide estimates of gas production during completion are for the Barnett (EPA , 2004; although the Barnett is not named in this reference), the Piceance (EPA, 2007), the Uinta (Samuels, 2010), and the Den Jules (Bracken, 2008) gas sands. These references report how gas production was recovered for sales and imply that this has been the case (at least for these companies) for several years! They emphasize the strong economic incentives for gas producers to capture and sell completion gases rather than vent them. Only one (EPA, 2007) provides explicit measurements of both captured (with "green technology") and lost emissions, and these numbers indicate a loss rate of 0.1% of total production. Howarth et al. cite the gas capture numbers in these references as representative of the gas leakage into the atmosphere that would occur if the gas was neither captured nor flared. They assume that this is the common situation, but do not make it clear that this is an assumption. They buttress their leakage estimates with the citations as if the latter explicitly documented methane leakage into the atmosphere, which they do not.

The large values for methane lost during completion that Howarth et al. suggest is routine industry practice is incompatible with elementary safety and economic considerations. Consider again the Haynesville case. Howarth et al. indicate that 6.8 million cubic meters of Haynesville natural gas (3.2% of a typical well's lifetime production) is released during an assumed flowback period of 10 days. Releasing 6.8 million cubic meters of gas into the atmosphere is equivalent to venting roughly $1,000,000 worth of natural gas (wholesale) from a single well. This leakage rate is equal to the consumption rate of 100,000 households, a city the size of Buffalo, NY (assuming 2.6 people per household) (EIA 2010). It's also a volume of potentially explosive gas so large that no driller (let alone their employees, contractors and regulators) would willfully release it. This volume of gas could cover a square mile of land with a combustible 5% mix of methane to a height of 176 feet, for example. Think how a homeowner worries what a very small emission from a gas stove might do to their house if not properly turned off before they leave for the theatre. The Howarth et al. leakage rate would fill a 3500 square foot house with an explosive mixture of 5% methane and air in 5 seconds. The idea that emissions such as Howarth et al. suggest occur on a routine basis in Haynesville Shale wells, or from any other large volume well, is simply not credible on safety considerations alone.

If an operator could find a way to safely vent such a high volume of shale gas, and preferred to do that over flaring or selling the gas, they could theoretically do so. It's illegal on this scale in most states (see 25 PA Code Sec. 78.74, for instance), and would clearly violate the terms of their liability insurance, but it could *physically* happen during initial production testing. As a practical matter, however, it doesn't happen on any scale except in very rare circumstances, such as a well blow-out, and it cannot happen during the periods when there is still substantial frac water in the well (generally the case during the drill out and early flow back periods) which is the period when Howarth et al. assert the methane is released.

Based on conversations we have had with people experienced in well completions, we believe the losses during drill out and well completion for unconventional shale gas wells are not significantly greater that that cited by Howarth et al. for conventional gas wells. Certainly this could be made to be the case. This is supported by some of the examples cited by the EPA and Howarth et al. The Williams Corp (EPA, 2007, p 14) shows, for example, that >90% of the flowback gas is captured and some of the remainder flared (George, 2011, p14). If this were generally the case Howarth et al.'s 1.9% leakage would be reduced to 0.2%. A life cycle analysis of a natural gas combined cycle power plant shows the total methane release from unconventional Barnett Shale hydrofractured gas wells is within a few percent of that from conventional onshore gas wells (DOE/NETL, 2010, Table 5.1 and Figure 5.1).

Howarth et al. support their very high leakage estimate in general terms by citing the EPA's (2010) conclusion that large quantities of methane accompany the flow back of water and are vented in the first few days or weeks after hydrofracture injection. The basis for the EPA's (2010, p. 84 ff) conclusion is their observation that 51% of the unconventional production (coal bed methane and shale gas only - no tight sands gas data was available) in 2007 was in Wyoming (of which none was from shale), where flaring is required by law, and 49% was in Texas, Oklahoma, and Louisiana, where it is not required, but isn't banned either. The EPA then assumed that where regulations did not require the methane to be flared, it was all released directly into the atmosphere (not flared or sold), and they generalized this to be universally true. Remarkably they thus conclude that 4.6 million cubic feet of methane (50% of the typical 9.2 million cubic feet that they estimate is produced from an unconventional gas well during flowback) is released into the atmosphere. For all the reasons discussed above, this is not credible and is clearly stated by the EPA to be speculative. They did not document the venting, and are very clear that the basis is the assumption that when not required by law to flare or sell gas, unconventional wells are vented during initial production. At least the EPA acknowledges that a significant portion of the methane emissions may be flared, rather than vented, in contrast to Howarth et al, who appear to assume 100% venting, the least likely scenario for real world operations.

It is also worth pointing out that much of the oil produced in the United States at present is either from hydrofractured wells or shale formations, and thus is unconventional oil. Almost every conventional and unconventional oil well also produces natural gas. A clean distinction between "conventional" and "unconventional" gas production, and between "oil" and "gas" wells, thus may be very difficult to make, as there is an enormous amount of overlap between these categories.

Methane leakage from the well site to the customer

The leakage that occurs between an operating well and consumers as the result of gas handling, processing, storage, and distribution is the same whether the well is producing from tight shale or conventional source rock. These losses are very hard to measure as they rely on a variety of sources that cannot be controlled in a scientific fashion. As well as true leakage you have to deal with questions of metering accuracy, shrinkage due to removal of higher order hydrocarbons, fuel use by compressors along the pipeline, etc. Trying to reach an estimate is important because various parties have a financial interest in the gas as it travels to the consumer, but scientific assessments are also encumbered by accounting conventions that relate to how gas transmission is charged to pipeline users. The results of most studies should not be considered accurate estimates that can be used for climate studies.

With well completion and drill out losses from both sources negligibly small (see above), the range of methane emissions that Howarth et al. identify is from 1.7 to 6% of total production. Leaking 6% of produced gas into the atmosphere during on-site handling, transmission through pipelines, and delivery appears to be far too high and at odds with previous studies. The most recent comprehensive study (EPA, 2011, Table 3-37, assuming a 2009 U.S. production of natural gas of 24 TCF) shows the emission of methane between source and user is ~2.2% of production of which 1.3% occurs at the well site, 0.73% during transmission, storage, and distribution, and 0.17% during processing. The EPA Natural Gas STAR program (EPA, 2009), a voluntary partnership to encourage oil and natural gas companies to adopt best practices, reports methane emissions of 308 BCF in 2008 This represents an emission of ~1.3% of total production. A life cycle analysis of combined cycle natural gas power pollutants suggests leakage can be much smaller. This report estimates ~0.9 wt% leakage of methane between source and consumer (DOE/NETL, 2010, Table 5.1), and suggests what best practices might achieve. A reasonable range for methane emissions to the atmosphere from U.S. pipelines (the proper subject of the current discussion) would thus appear to be between 0.9 and 2.2% of production.

Excepting completion and drill out losses, the losses during transmission, storage and distribution, which Howarth et al. claim are conservatively 1.4 to 3.6% of production, constitute the largest fraction of their range of total gas losses of 1.7 to 6%. Howarth et al.'s transmission, storage and distribution losses are 2 to 5 time higher than the EPA(2011) estimate of 0.73%. Even their low end estimate seems far too high. Furthermore, many organizations have addressed these leakages, and many are striving to reduce them. Even if a 6% leakage rate were true in the US (the losses in Russia and elsewhere are irrelevant in the context of US policy decisions), the obvious policy implication would surely be to "fix the leaks". Of all the possibilities one could think of, this should be the easiest, most accessible, and least costly way to reduce greenhouse gas emissions, and something that should be done regardless of how a comparison of gas and coal turns out.

Conclusions

We have highlighted two aspects of the recent letter from Howarth et al. that we believe are either erroneous or misleading. The first aspect is the question of just how much unconventional produced gas gets directly into the atmosphere as methane during drilling, production, and transmission. We show that not only are the authors overestimating and confusing the available data, which is of poor quality to start with, they also do not appreciate that modern operating techniques, production incentives, and safety mitigate against the extreme release rates they present. We suggest that Howarth et al.'s assessment of the leakage from shale gas production is overestimated by a factor of ~20 and technological improvements will continue to reduce venting from both conventional and unconventional wells.

The second aspect of this paper that we question is the effect of methane leakage from gas drilling on greenhouse gases and the future climate. In addition to using inflated leakage estimates, they compute the GHG impacts using the most disadvantageous and erroneous assumptions regarding the time period (20 years vs 100 years) and basis (heat vs electricity) for comparing gas with coal. More realistic and appropriate assumptions confirm that on the basis of CHG impact (let alone the other environmentally important emission considerations such as particulates, SO_2, NO_2, ash) gas remains clearly the "cleaner" option in comparison to coal. Howarth et al. arrive at the conclusion that gas could have twice the greenhouse impact as coal only by considering fugitive gas emissions 3.6 times larger than reasonable (e.g. 2.2%), selecting a Global Warming Potential at least 3.2 times too big, and failing to consider that a modern gas plant can generate electricity nearly twice as efficiently (and therefore with half the GHG input) as old coal plants.

It is of course possible, although we consider it highly unlikely, that methane emissions from wells and pipelines might be as large as Howarth et al. aver. But, as they admit, these leaks could be economically and relatively easily fixed. Addressing whatever deficits natural gas might have at present so that it realizes the potential GHG benefits that are indicated in our Figure 1 seems to us a goal eminently more achievable with current technology, and far more economic and less risky than relying on undeveloped and unproven new technologies to achieve the same degree of GHG reduction. Surely we need to consider how to reduce GHG emissions for all fuels, and should do the best we can with all the fuels we are using and are likely to continue using for some time.

We further suggest that to address the real environmental problems associated with all energy sources depends upon a partnership between academic and industry scientists who can marshal the necessary expertise needed. An adversarial approach is unlikely to yield accurate assessments or effective solutions.

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Equities

17 August 2011 | 24 pages

Coal Seam Gas & Greenhouse Emissions

Comparing Life Cycle Emissions for CSG / LNG vs Coal

- Industry Overview

Elaine Prior

with input from:

Dale Koenders

- **Coal Seam Gas as a Transition Fuel** — Gas is promoted as a transition fuel in a carbon constrained world. Gas power station emissions are generally lower than for coal. However, when CSG is converted to Liquefied Natural Gas (LNG), shipped, regasified and then burnt, emissions occur at each stage. In a carbon constrained world, life cycle emissions may affect carbon costs, CSG/LNG demand, and regulatory and public support for the industry. We analysed Australian CSG/LNG emissions data. We found it generally compared favourably with coal, assuming that actual performance meets company and industry projections, but not in all scenarios. In the longer term LNG might be compared with renewables rather than coal.

- **CSG/LNG Emissions Generally Lower than Coal** — We analysed emissions data from the Environmental Impact Statements for the APLNG and GLNG projects, and reviewed a study conducted for APPEA, which also included data on coal. CSG/LNG generally showed lower emissions than coal. Assuming gas is burnt in a baseload CCGT power station, lifecycle emissions of 0.48-0.58 tCO2/MWh were estimated (Figure 1, Figure 2). Coal numbers varied widely (0.58-1.56 t/MWh), with 0.83-1.03 as the base case for subcritical and supercritical coal plants. Power station efficiency is the key variable, and both gas and coal may improve over time. Emissions for ultra supercritical coal plant was given as 0.79 t/MWh (base) and 0.58 (low case) (Figure 7).

- **Fugitive Gas** — The CSG projects appear to assume that minimal quantities of methane gas escape as fugitive emissions. Financial incentives to minimise fugitives include the carbon cost that would apply in Australia, and loss of product gas. New infrastructure will presumably be constructed and maintained to minimise leaks. However, fugitives depend heavily on actual operating practices, including ship operations, and we are not yet convinced that all these are well understood. If fugitive emissions were 1% higher than the numbers in this report, this would add an estimated 0.034 t/MWh (6-7%) in the CCGT case (Figure 8).

- **Can CSG/LNG Maintain its "Transition Fuel" Role?** — Power station efficiency will probably improve over time. The CSG/LNG process has significantly higher emissions outside the power station (Figure 3, Figure 4), so focus on minimizing these emissions may be important to maintaining CSG/LNG's claim as a "transition fuel" in an increasingly carbon constrained world. A "worst case" CCGT scenario results in an estimate of 0.7t/MWh, significantly higher than the "best case" coal at 0.58.

- **Shale Gas – Different from CSG** — Differences between shale gas and CSG are sometimes misunderstood. Some critics of the Australian CSG industry quote studies on US shale gas that suggest gas emissions may not be lower than coal. Figure 9 gives a comparison of CSG, shale gas and conventional gas, highlighting geological and operational factors that cause different GHG emissions characteristics. On Page 17 we discuss a frequently referenced US paper on shale gas emissions.

See Appendix A-1 for Analyst Certification, Important Disclosures and non-US research analyst disclosures.

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Table of Figures

Investigating CSG / LNG Greenhouse Gas Emissions and Comparison with Coal

Gas, including Coal Seam Gas (CSG), is promoted as a useful fuel to replace coal for power generation in an increasingly carbon constrained world.

Burning gas in a power station tends to generate greenhouse gas (GHG) emissions of ~0.4-0.6 t CO2e/MWh, compared with ~0.7-1.0 t/MWh for coal fired power stations of different efficiencies. A new gas fired baseload power station would have roughly half the emissions of a typical coal plant.

However, the CSG industry in Australia faces opposition on several grounds. Key issues include the industry's impact on water, and impact on agriculture and rural communities.

Focus on Life Cycle Emission Comparisons Is Now Increasing

CSG – Coal Seam Gas

LNG – Liquefied Natural Gas

GHG – Greenhouse Gas

CO2e – Carbon Dioxide equivalent

MWh – Megawatt Hour (of electricity)

The Australian CSG industry will primarily produce Liquefied Natural Gas (LNG) for export to countries including China, Japan and Korea.

Some industry critics challenge whether GHG emissions from CSG are indeed lower than coal, once the full "life cycle" is taken into account. This includes GHG emissions that occur during gas production, processing into LNG, shipping and regasification in the customer country.

Some critics of the Australian CSG industry refer to reports that gas from shale does not have a GHG benefit over coal. Shale gas and CSG have differences that impact their emissions profiles. A comparison of CSG, shale gas and conventional gas is shown in Figure 9. A widely-cited shale gas report by Howarth (Cornell University) is discussed on Page 17.

Emissions Intensity May Impact Longer Term CSG / LNG Demand

We aimed to investigate CSG/LNG life cycle GHG emissions and how they compare with coal. This is relevant to long-term investors for various reasons.

It is often argued that gas will fare better than coal in a carbon constrained world. This is because once a carbon cost is broadly applied, the cost of using coal will increase more substantially, making gas a more cost competitive choice of fuel. Whether carbon costs for CSG/LNG compare favourably with coal (when assessed across the entire production chain) may influence long-term costs and demand.

Regulatory and community support for the industry may partly relate to the role of gas in the transition to a carbon constrained world.

Minimising the emissions footprint of a CSG/LNG project would appear appropriate to reduce potential carbon costs, maintain the profile of gas as a low emissions transition fuel, and sustain support for the industry. Higher-than-anticipated carbon costs, lower demand, and / or lower industry support might pose investment risks. Since CSG / LNG projects are long term in nature, such risks could eventuate over the project lives.

On Page 15 we discuss whether renewables, rather than coal, might become the more appropriate comparison in the longer term.

Summary and Key Conclusions

We analysed emissions data for the Queensland CSG to LNG industry from three sources:

- **APLNG**: The Australia Pacific LNG Project (Origin & ConocoPhillips) Environmental Impact Statement;
- **GLNG**: The Gladstone LNG Project (Santos, PETRONAS, Total & KOGAS) Environmental Impact Statement; and
- **APPEA**: The April 2011 study conducted for APPEA (the Australian Petroleum Production and Exploration Association) by WorleyParsons on Australian CSG/LNG and a GHG emissions comparison with coal.

Base Case Conclusions

EIS – Environmental Impact Statement

CCGT – Combined Cycle Gas Turbine (power station)

OCGT – Open Cycle Gas Turbine (power station)

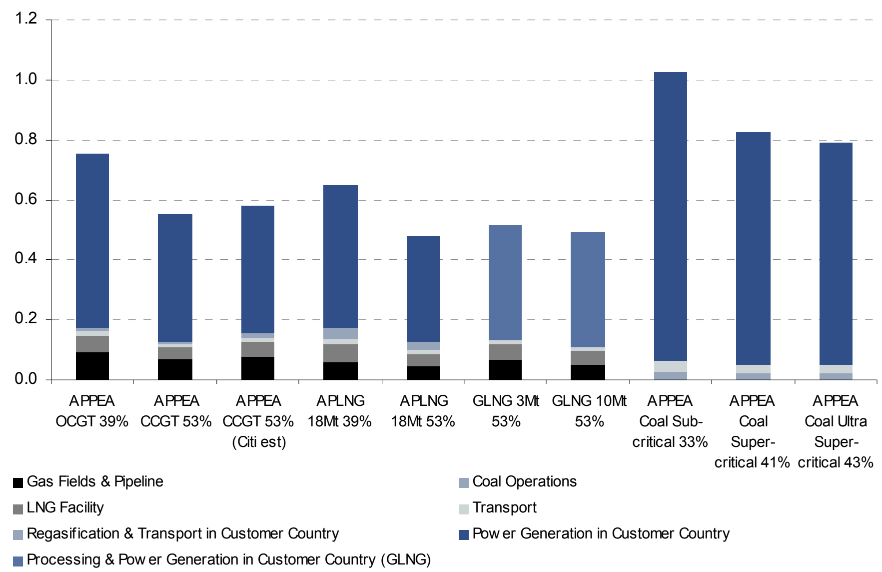
Based on the abovementioned data sources, life cycle GHG emissions for CSG/LNG consumed in a 53% efficient CCGT power station (China or Japan) appear to be 0.48-0.58 t CO2e/MWh (Figure 1, Figure 2). While composition differs, the APPEA study shows higher emissions than we derived from the APLNG and GLNG data. A CCGT plant appears the appropriate assumption for baseload generation.

Results are inversely proportional to the efficiency of the consuming power station. Emissions intensity would be closer to 0.65-0.79 t/MWh in a 39% efficient OCGT plant.

Coal scenarios are based on assumptions of efficiencies ranging from 33% to 43%.

In all cases, the majority of emissions arise at the customer's power station.

Figure 1. Life Cycle GHG Emissions Comparison For Various CSG/LNG and Coal Scenarios (t CO2e/MWh)



Source: Citi Investment Research and Analysis

Figure 2. Life Cycle Greenhouse Gas Emissions Data For Various CSG/LNG and Coal Scenarios (t CO2e/MWh)

	CSG / LNG							COAL		
	APPEA OCGT 39%	APPEA CCGT 53%	APPEA CCGT 53% (Citi est)	APLNG 18Mt 39%	APLNG 18Mt 53%	GLNG 3Mt 53%	GLNG 10Mt 53%	APPEA Coal Sub-critical 33%	APPEA Coal Super-critical 41%	APPEA Coal Ultra Super-critical 43%
Gas Fields & Pipeline	0.090	0.067	0.080	0.060	0.044	0.067	0.050			
Coal Operations								0.028	0.023	0.023
LNG Facility	0.058	0.042	0.050	0.057	0.042	0.052	0.047			
Transport	0.015	0.011	0.013	0.021	0.015	0.014	0.013	0.034	0.028	0.027
Regasification & Transport in Customer Country	0.012	0.009	0.010	0.037	0.027					
Power Generation in Customer Country	0.578	0.425	0.425	0.474	0.348			0.965	0.777	0.74
Processing & Power Generation in Customer Country (GLNG)						0.383	0.383			
Total	**0.753**	**0.554**	**0.578**	**0.649**	**0.477**	**0.516**	**0.493**	**1.027**	**0.828**	**0.790**

Source: Citi Investment Research and Analysis

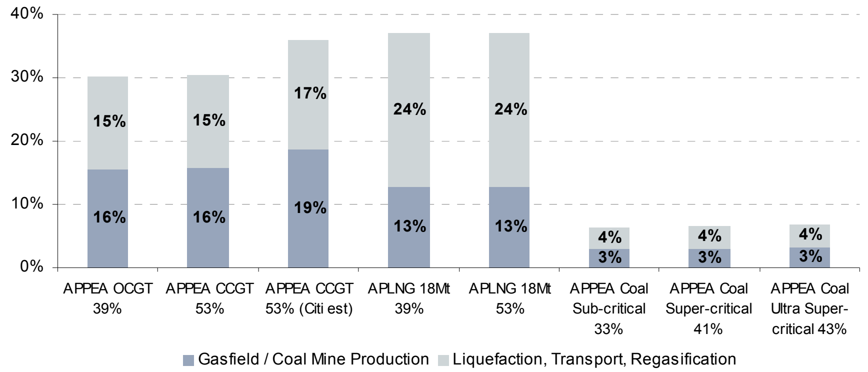
Emissions Outside the Power Station

Comparisons of gas versus coal often refer to power station emissions.

Figure 3 illustrates the magnitude of emissions in other parts of the lifecycle, presented as a percentage of the emissions that occur in the power station step.

For CSG/LNG emissions in production, processing, transport and regasification equate to around 30-37% of the emissions that occur in the power station. For coal, the production and transport emissions are roughly 6-7% of power station emissions, under base case assumptions. (Figure 6 shows each component as a percentage of the total.)

Figure 3. Emissions in Production, Processing and Transport as a Percentage of Emissions at the Power Station

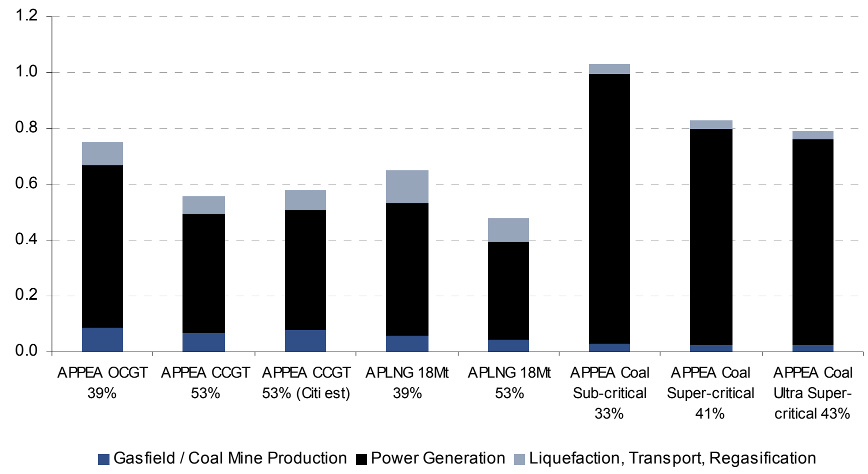


Source: Citi Investment Research and Analysis

Figure 4 illustrates the magnitude of production/mining emissions, and processing and transport emissions, compared with power generation emissions.

Liquefaction, transport and regasification are shown as the top component. If the comparison was between coal and gas production for domestic power generation, these emissions would not be incurred.

Figure 4. Emissions Comparisons for CSG/LNG and Coal – Identifying Liquefaction, Transport and Regasification Components (t CO2e/MWh)



Source: Citi Investment Research and Analysis

Sensitivity to Fugitive Emissions

GWP – Global Warming Potential

Fugitive emissions of methane (eg leaks) contribute to GHG emissions. One tonne of methane is generally considered to have the Global Warming Potential equivalent to 21x to 25x a tonne of CO2.

Low Fugitives Assumed – Our interpretation is that the APLNG and GLNG projects both assume ~0.1% of well gas is lost as fugitives throughout the production and liquefaction process. The GLNG EIS says this estimate is conservative. We suspect these estimates are subject to some uncertainty, and quantification may become more accurate over time.

Incentives to Minimise – There are financial incentives to minimise fugitives. A carbon cost would potentially be incurred under an Australian carbon scheme, and fugitive emissions equate to loss of product gas. Australian industry infrastructure is new, and will presumably be well maintained, so leaks should be minimized. The reality will presumably depend on the costs vs benefits of implementing best practice technologies and operating procedures.

Best Practice a Key – The APPEA study notes that it assumes CSG/LNG projects apply best practice, especially to the prevention of venting and leaks in upstream operations. Actual emissions will depend on actual operational practices. Since this may be a critical assumption, we conducted sensitivity analysis (see Page 12).

Dewatering – CSG wells generally go through a multi-month dewatering process before gas production begins. Best practice would require surface facilities (well separator, gathering lines) to be installed early in the dewatering phase to avoid venting gas with produced water.

Shipping – Whether / how much venting occurs from ships during transport will depend partly on the actual ships used.

Sensitivity Estimate – We found that an additional 1% of fugitive emissions would add ~0.034t/MWh in the CCGT case (~6-7% of total life cycle emissions). This would take total emissions to 0.51-0.61t/MWh (Figure 8).

Coal and Gas Comparisons

Coal Life Cycle Emissions – Emissions vary depending on power station technology and efficiency (Figure 2). The APPEA study shows a wide range between minimum and maximum assumptions – 0.58-1.56 tCO2e/MWh (Figure 7).

"Base Case" Looks Favourable for CSG/LNG Compared with Coal – Under various "base case" assumptions, CSG/LNG used in a CCGT power station (0.48-0.58 t CO2e/MWh - Figure 2) compares favourably with all the APPEA study's base case coal assumptions (0.79-1.03 t/MWh - Figure 2, Figure 7).

Less Favourable Scenarios Possible – The APPEA study presented minimum and maximum life cycle emissions estimates around its base case numbers for each scenario studied.

A "Worst Case"

Our interpretation of the APPEA study suggests a base case number of 0.58 for the CSG/LNG/CCGT scenario (Figure 2), not 0.55 as the study reports. Therefore, the corresponding maximum case might be closer to 0.66 than 0.64. If we add 1% fugitives (0.034) the CSG/LNG/CCGT scenario could increase to ~0.7t/MWh.

In the "worst case" for CSG/LNG/CCGT, we could see life cycle emissions of 0.7t/MWh, compared with the more efficient coal options (supercritical or ultra supercritical – 0.61 and 0.58 - Figure 7). However, it is more likely that both gas and coal technologies will become more efficient over time.

Future Efficiencies

Future Power Station and Production Efficiencies a Key

In reality, both coal and gas power stations will probably become more efficient over time. For example, the US Department of Energy is targeting efficiencies greater than 60% for coal-based systems and 75% for gas-based systems. This compares with the best numbers used in this analysis of 43% for coal and 53% for gas.

Since life cycle emissions per MWh are inversely proportional to power station efficiency, this could mean emissions in both cases fall to 71-72% of the numbers in this report.

Assumptions are Critical to Conclusions

The discussion above demonstrates that various key assumptions are critical to the conclusions. Power station efficiency is the most critical variable. Uncertainty over some aspects of operational emissions, including fugitives, also makes definitive conclusions challenging.

For most scenarios, CSG/LNG/CCGT appears to have lower life cycle emissions than coal. However, if coal power stations become more efficient, perhaps with the build of more ultra supercritical coal, the CSG/LNG/CCGT process will presumably also come under pressure to improve efficiency and minimise emissions.

Suggests Continued Focus on Gas Emissions Outside the Power Station – Since the CSG/LNG process has significantly higher emissions outside the power station (Figure 3, Figure 4), continued focus on minimizing these emissions may be important to maintaining CSG/LNG's claim as a "transition fuel" in an increasingly carbon constrained world.

Longer Term – Comparison with Renewables, Not Coal?

In the longer term, if there is a concerted move to a carbon constrained world, this analysis might become redundant. Instead, the appropriate comparison might be between gas and new build renewable energy technologies.

Fossil fuel use (including CSG/LNG) might become more costly under a widespread carbon price, or if carbon capture and storage is implemented. The merits of CSG/LNG over coal could become less relevant, and comparison with renewables potentially more relevant.

Life Cycle Emissions from Australian CSG to LNG Compared with Coal

We analysed emissions data for the Queensland CSG to LNG industry from three sources (APLNG, GLNG, and an APPEA study). Our analysis required various assumptions and estimates, and we attempted to ensure consistency.

We “normalized” the data to tonnes CO2e per MWh of electricity produced in the customer country.

We also show emissions scenarios for coal exported from Australia for consumption in China, as reported in the APPEA study.

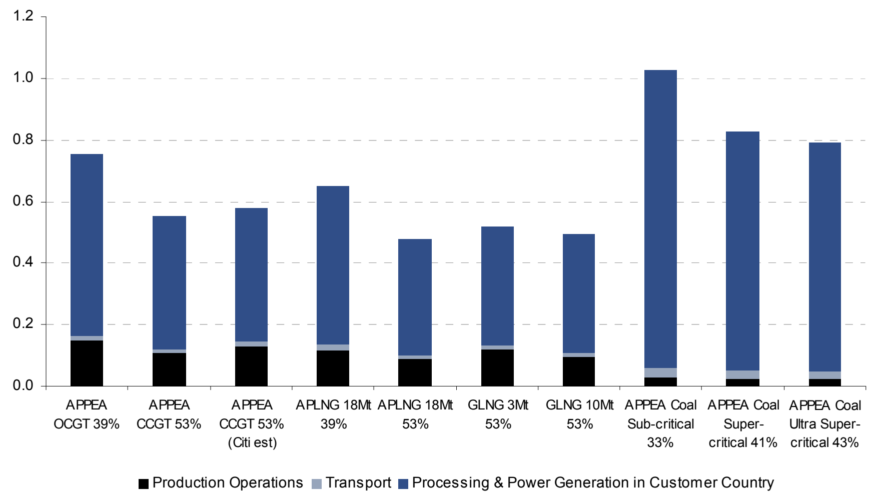
For CSG / LNG operation, the key sources of gas field emissions are fuel used as energy for drilling equipment, power generation, transport, and gas compression. At the LNG facility, fuel is used to generate electricity, and to power the refrigeration compressors that turn gas into LNG. A small proportion of emissions come from venting and flaring or fugitive emissions (leaks).

LNG is also likely to be used for fuel for the ships and as fuel for the regasification process on arrival in the customer country.

The comparisons are shown in Figure 1 and Figure 2. Our conclusions differ slightly from those presented in reports we sourced data from. We are happy to discuss reasons for these differences with clients.

Figure 5 illustrates the same emissions data collated into three categories – Australian production, transport (ie shipping), and processing/consumption in the customer country.

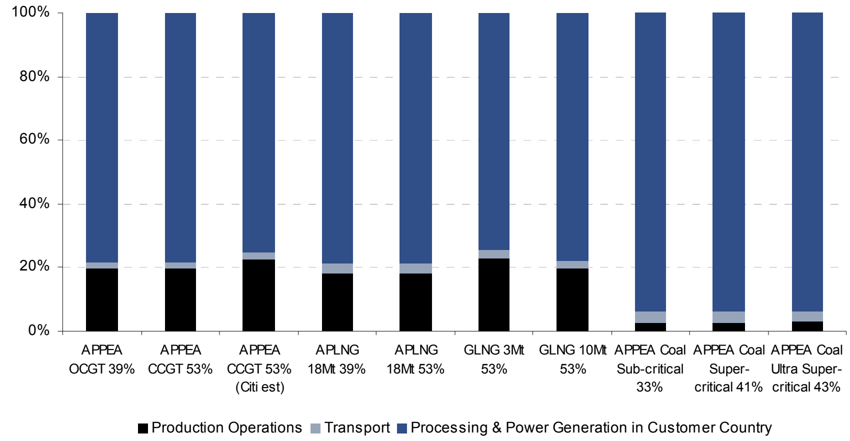
Figure 5. Life Cycle GHG Emissions Key Components For Various CSG/LNG and Coal Scenarios (t CO2e/MWh)



Source: Citi Investment Research and Analysis

The majority of emissions in all scenarios come from the customer's power station. (see Figure 6).

Figure 6. Proportion of GHG Emissions from Production Operations, Transport and Consumption in Customer Country



Source: Citi Investment Research and Analysis

LNG Scenarios & Projects Analysed

APLNG Project

We analysed data from the project's Environmental Impact Statement (EIS), which presents data for the 18 Mtpa project. In July, a Final Investment Decision was made on an initial project comprising two 4.5 Mtpa trains, or 9 Mtpa total. We made minor adjustments to account for LNG consumed during LNG shipping and regasification, resulting in less gas used in the customer power station (assumed in the EIS to be in Japan). Our base case assumption (based on the EIS – 18 Mtpa project) is that the LNG that arrives (~16Mt) is burned in a Combined Cycle Gas Turbine (CCGT) plant with 53% efficiency.

GLNG Project

We analysed data from the EIS and Supplementary EIS, which presents data for the 3 Mtpa and 10 Mtpa projects. The actual project will be two trains, making a total of 7.8 Mtpa. Our base case for comparison is that the fuel is consumed in a CCGT plant (53% efficiency). The EIS scenario assumes the customer is in Japan.

APPEA Study

APPEA (the Australian Petroleum Production and Exploration Association), on behalf of several members including Santos, commissioned WorleyParsons to conduct an independent analysis. The study was published in April 2011. The aim was to compare life cycle emissions of CSG / LNG when consumed in China with export coal consumed in China. Santos assisted us to understand the assumptions and inputs to the study. A generic 10 Mtpa project was assumed.

The results are shown for gas power stations of 39% and 53% efficiencies, and coal fired power stations of different efficiencies (33%, 41% and 43%).

Best Practice Assumed (Perhaps a Critical Assumption) – The APPEA study assumes that CSG/LNG projects apply best practice in GHG and environmental management, especially to the prevention of venting and leaks in upstream operations. Since this may be a critical assumption, we conducted sensitivity analysis, as discussed on Page 12.

APPEA: The Coal Scenarios

The study assumes a 10 Mtpa Australian opencut mine, with coal railed and shipped to a consuming power station near the receiving port in China.

Coal Mine Fugitives

One key variable for coal is the level of fugitive emissions, which vary widely between mines. The APPEA study assumes 0.0375 tCOe2/t coal, which appear reasonable to us. Typical Australian coal mines have fugitive emissions in the range of 0.01-0.05t/t (0.02-0.04 is common). A small number of "gassy" mines lie between 0.1 and 0.8 t/t.

If fugitive emissions were ~0.1t/t, total emissions per MWh of power would increase by ~2.5%.

Power Station Assumptions

Our base case assumption for gas is that LNG is consumed in a Combined Cycle Gas Turbine (CCGT) plant with 53% efficiency. This is the base case efficiency assumption used in the APPEA study. CCGT is more appropriate for baseload generation than an Open Cycle Gas Turbine (OCGT) plant (efficiency ~39%).

The APPEA study's coal assumptions involve power stations with varying efficiencies:

- Subcritical – 33% efficiency
- Supercritical – 41% efficiency
- Ultra supercritical – 43% efficiency

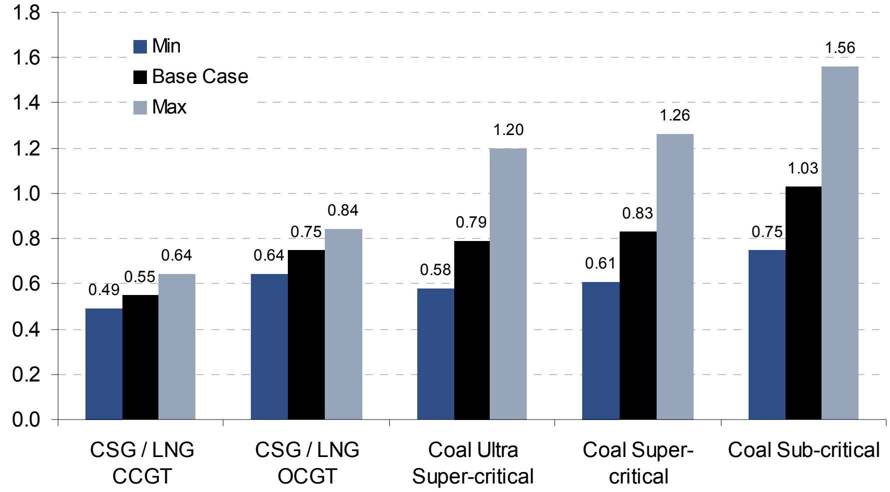
The most appropriate comparison may change over time. Subcritical plant currently dominates China's generation plant. Over the 2006-2010 period, new build in China was 34% subcritical, 45% supercritical and 20% ultra-supercritical (source IEA / Productivity Commission). Over time, new build of ultra supercritical might increase.

As mentioned on Page 7, the US Department of Energy is targeting efficiencies greater than 60% for coal-based systems and 75% for gas-based systems.

APPEA Study Results & Ranges

The APPEA study conducted by WorleyParsons showed a range of outcomes for each scenario (Figure 7). Sensitivity bands reflected uncertainties and ranges in power plant efficiencies – the latter is a critical variable. The primary assumption is that the coal scenarios should be compared with CCGT gas technology, as being more appropriate for baseload generation.

Figure 7. APPEA Life Cycle Emissions Results for LNG & Coal – Base, Minimum & Maximum Cases (tCO2e/MWh)



Source: Citi Investment Research and Analysis, WorleyParsons, APPEA
Note that our interpretation of the APPEA study data gave slightly different conclusions for gas. Our (slightly higher) emissions numbers are used in Figure 2, Figure 1, Figure 5 and Figure 8.

Leaks / Fugitives May Be a Key Variable

We estimated the sensitivity to assumptions about leaks of gas during CSG / LNG operations. Quantification and measurement of leaks / fugitives appears imprecise at present, and generalized assumptions tend to be made.

Actual emissions will depend on operating practices, including what equipment is installed and how it is operated and maintained. Challenges include the large number of wells required for CSG operations, creating many sites to be managed.

The quantity of fugitive emissions that arise during shipping may depend on the age and technology of ships used. This may be under the customers' rather than the projects' control.

Strong Incentives to Minimise Fugitive Emissions

We expect the Australian CSG / LNG industry to have a strong incentive to minimize fugitive methane emissions for various reasons.

A carbon cost will be incurred on operational emissions including fugitives. Minimization of leaks means more product is kept "in the pipe" and available for sale. The infrastructure will be new, so should be in good condition. Technically sound well completions should avoid potential problems including gas leaks, as well as flow of fluids between formations via the wellbore, which could cause aquifer contamination problems.

Flaring rather than venting of gas converts methane to CO2, which has a lower global warming potential, so may be a preferred operating practice when the aim is to reduce GHG emissions.

Sensitivity to Each 1% More Fugitives

The APPEA study assumes that projects apply best practice for GHG mitigation. The GLNG (Santos) project EIS assumes fugitive gas losses of 0.1% in the gas fields, which it says is a conservative estimate and based on industry accepted practices. Our analysis of emissions projections from the APLNG project EIS suggests fugitives, leaks and venting of 0.1%, mainly from CSG venting in the gas fields.

We estimated the sensitivity to a 1% increase in fugitive methane in gas field operations. We assumed that more gas would be produced, so there would be slightly higher operational emissions in parts of field operations. The same quantity of gas as in the base case would be delivered to the LNG plant and to overseas customers, and the same quantity of electricity produced by customers.

Each 1% Higher Leaks / Fugitives Adds ~0.03-0.05 tCO2e/MWh

- For each extra 1% of well gas that is leaked as fugitives, lifecycle emissions increased by an estimated 0.03-0.04t/MWh assuming 53% power station efficiency.
- In the 39% efficiency case, the increase was an estimated 0.04-0.05 tCO2e/MWh.
- Each 1% increase in gas field fugitives equates to an estimated 50-80% increase in emissions from field operations, and a 6-7% increase in total project life cycle emissions per MWh.

Figure 8. Emissions Sensitivity to 1% Additional Fugitives For CSG/LNG Scenarios (tCO2e/MWh)

	APPEA OCGT 39%	APPEA CCGT 53%	APPEA CCGT 53% (Citi est)	APLNG 18Mt 39%	APLNG 18Mt 53%	GLNG 3Mt 53%	GLNG 10Mt 53%
Total Base Case	**0.753**	**0.554**	**0.578**	**0.649**	**0.477**	**0.516**	**0.493**
Increment for 1% Fugitives	0.046	0.034	0.034	0.046	0.034	0.034	0.034
Total Plus 1% Extra Fugitives	**0.799**	**0.588**	**0.612**	**0.695**	**0.511**	**0.550**	**0.527**

Source: Citi Investment Research and Analysis

How Much Gas Is Used in Operations?

Some of the gas produced from wells is consumed as energy for the gasfield and LNG operations. A small quantity escapes (venting, flaring, fugitives). We have derived the following estimates.

APLNG – From CO2e emissions data in the EIS, we estimate that ~8% of gas produced from the wells is consumed in gas field operations (including 7% as useful energy); ~8% in LNG operations (almost all as useful energy); and ~9% for LNG shipping fuel and energy for regasification in the customer country. Leaks, fugitives and venting appear to be ~0.1% of production, increasing to 1.5% if flared gas is also included. In total, roughly 25% of produced gas is consumed in operations.

GLNG – It is more difficult to estimate gas consumed during the process from the emissions data in the EIS (since it is not clear what emissions come from CSG consumption vs diesel), but the total (including shipping and regasification) appears to be less than 28%. We "back calculate" a number of 3.5% for shipping/ regasification from emissions data, but cannot be confident of our interpretation.

APPEA Study – Gas use for the process is roughly 15% of production in the fields, 8% at the LNG plant, and 3% for shipping / regasification, making a total of 26% of production.

Is 3% to 9% a Realistic Range for Shipping?

We are puzzled that the shipping / regasification numbers we have deduced vary from 3% to 9% of field gas, though the available data does not allow precise calculation.

We understand that often the ships will be the responsibility of the customer. LNG ships may be powered by LNG, diesel, or a combination of these fuels. "Boil-off" gas may be vented, used as ship's fuel, or re-liquefied, depending on the technology and chosen operating practices of the ships used.

We welcome further information and clarification from industry on ship technology, fuel use (LNG vs diesel), and estimates of fugitive emissions during shipping.

Domestic and Export Life Cycle Components Vary

Comparison between life cycle greenhouse gas (GHG) emissions of gas and coal depends on the scenario being investigated.

Gas Variables

For gas, variables include whether the gas is piped to the consuming power station, or whether there is the added step of converting into LNG, shipping, then regasifying. The geology of the resource is also relevant, with different GHG emissions profiles for conventional gas, coal seam gas and shale gas. Reservoir CO2 content is also variable. Life cycle emissions for shale gas delivered to a nearby market will have different components to emissions from CSG/LNG shipped to a distant market.

Coal Variables

For coal, there are fewer variables. These include whether the coal is shipped to a distant market, and whether there are significant fugitive emissions associated with production from the particular mine/s.

Comparison Would be Very Different for Domestic Operations

If we were comparing domestic operations, where the power station consumed domestic gas or coal produced nearby, we would remove emissions associated with the LNG facility and regasification for the gas case, and transport (shipping) for both coal and gas.

The magnitude of these numbers is shown as the top category in Figure 4. In this "domestic" scenario, the relative attractiveness of gas over coal, from a GHG perspective, increases.

Might Renewables Become the Benchmark for Gas, Rather than Coal?

Gas is compared with coal under the assumption that gas will displace potential coal use in power generation during transition to a carbon constrained world. However, gas still has significant GHG emissions, and it appears unlikely that the 2°C global warming scenario will be achieved unless electricity generation is largely decarbonised.

The OECD/IEA "*World Energy Outlook 2010*" presents a "450 Scenario". This is an energy pathway consistent with the goal of limiting global warming to 2°C, requiring the atmospheric GHG concentration to be limited to ~450ppm of carbon dioxide equivalent (CO2e). Under this scenario, the IEA shows world gas demand peaking before 2030, and incremental gas generation capacity is largely associated with Carbon Capture and Storage (CCS). See our report "*World Energy and Carbon Outlook - Climate Change Targets Challenging Under OECD/IEA Projections*" of 16 November 2010.

Achieving global policies required for the 450 Scenario looks challenging. However, in an increasingly carbon constrained world, gas might be judged against lower emissions alternatives such as renewables, rather than being compared with coal.

Key Differences Between Coal Seam Gas, Shale Gas and Conventional Gas

Figure 9 provides a comparison of typical coal seam gas, shale gas and conventional gas reservoirs, focusing on factors relevant to greenhouse gas emissions. The key differences relate to how the gas is stored geologically in the reservoir, and the process used to get it out of the ground. The actual methane product is essentially the same in all cases, so beyond the wellhead the process is the same.

Figure 9. Comparison of Coal Seam Gas, Shale Gas and Conventional Gas, Highlighting Factors Relevant to Greenhouse Gas Emissions

	Coal Seam Gas	Shale Gas	Conventional Gas
Geology	Gas (methane) is generated in the coal seams as part of the process of the coal forming (via decay of organic material). Gas is attached to coal (adsorbed onto the coal). Water may also be present in the spaces and voids in the coal seam.	Gas (methane) is generated in the shale as part of the process of the shale forming (via decay of organic material). Gas is attached to shale (adsorbed onto the organic material), and also present in natural fractures/pore space. Water may also be present, but less likely than CSM given lower permeability.	Gas exists in the pore space of rock. Typical reservoir rock is sandstone or limestone.
Production	Generally downhole pressure needs to be reduced before gas molecules will detach from the coal and flow into the wellbore. For most wells in Queensland this involves a 1-12 month dewatering process before gas flows. Some CSM operations do flow gas with minimal water production.	Post fracture stimulation, shale wells need to go through a "clean up" phase where the frac water is pumped/produced from the well. Volumes of water recovered from the wells are generally < water pumped into the well.	Gas flows naturally into well bores. Gas typically sits above the reservoir water, and flows preferentially into the wellbore. Water production generally spells the end of well life.
Typical Depths	CSM operations generally target depths of 300m-1200m. Shallower coal seams often have water production issues, deeper coals generally have low permeability which results in sub-economical flow rates.	Shales with appropriate thermal maturities need to have been exposed to sufficiently high pressures and temperatures and thus are generally found at depths of 1000-4000m.	Conventional onshore gas depths range from <500m to >5km.
Fracture Stimulation (Fraccing)	CSM has low, but adequate permeability to achieve commercial flow rates. For some wells operators look to increase the surface area of coal being produced from by either using horizontal wells or fracture stimulated vertical wells. Well design selection depends on geology and economics. Since gas does not start to flow until formation water has been produced, significant quantities of gas would not be produced during the flow back of fracture stimulation fluids or reservoir water.	Shale has a very low permeability and thus wells need to be fractured to achieve adequate flow rates (create high permeability pathways for gas to flow through, and increase drainage area). Some methane (a greenhouse gas) is produced during flow back of fracture fluids. Most operators currently vent to the atmosphere or flare (reducing the greenhouse gas impact), but the gas can be captured if adequate facilities are installed. The choice of technology employed therefore significantly determines the quantity of GHGs released during this process.	High permeability conventional wells do not need fracture stimulation, but fraccing has been used for many years in tight-gas (low permeability fields) in Australia and abroad.
CO_2 Content of Gas	Commercial operations are typically low (0-5%), though coal seams can have CO_2 contents >50%.	Depends on the thermal maturity (geology) of the shale. Typically 0-5%, but can be >20%.	Variable, some fields have >90% CO_2, but like CSM and shale the presence of CO_2 impacts the commerciality of the resource. Most commercial developments <20% CO_2.
Greenhouse Gas (GHG) Emissions Summary	Mostly low CO_2 content of reservoir gas. Insignificant methane production during flow back of fraccing fluids.	Typically low reservoir CO_2 content. Methane may be produced with flow back of fraccing fluids – the GHG impact depends whether this is vented, flared or captured for sale.	Primarily depends on amount of CO_2 in reservoir gas.

Source: Citi Investment Research and Analysis

Cornell Study – Limited Relevance to CSG

Some critics of the Australian CSG industry refer or allude to a paper by Howarth ("*Methane and the greenhouse-gas footprint of natural gas from shale formations*" by Robert Howarth of Cornell University, Ithaca, NY, published in March 2011).

This paper is primarily focused on the US shale gas industry, and claims that gas from shale does not have a lower lifecycle GHG footprint than coal. It is sometimes cited to challenge the GHG merits of Australian CSG over coal.

The paper makes some questionable assumptions that significantly influence the conclusions, some of which clearly do not apply to CSG.

Methane Venting and Leaks

Howarth estimates that 3.6% to 7.9% of the methane escapes via venting or leaks.

A significant proportion (1.9%) is attributed to flow back fluids after fracturing (1.6%) and to drill out of plugs set during fracturing (0.33%). Figure 9 discusses how emissions from flow back after fraccing CSG wells would typically be less significant.

Emissions during transport, storage and distribution are cited at 1.4% to 3.6%. Data sources appear to be patchy, and include consideration of Russian pipeline performance and derivation of "lost and unaccounted for gas" in Texan systems. New Queensland infrastructure appears likely to result in fewer leaks than historical data from Russia and the US might indicate.

The APLNG and APPEA study both estimate very low fugitive emissions for the operations as a whole. For example, both projects estimate 5,000 t CO2e from the pipelines, representing ~0.002-0.004% of production. The APLNG project EIS suggests fugitives, leaks and venting of 0.1%, an assumption also made for GLNG.

We suspect there is more to be learnt about quantifying fugitives, leaks and venting, before numbers can be projected with confidence. Therefore, we conducted the sensitivity analysis discussed on Page 12.

Global Warming Potential of Methane

To calculate the global warming impact of different gases, the Global Warming Potential (GWP) is used to convert the impact into a CO2 equivalent. Current convention is to use a factor of 21x to 25x for methane, based on the IPCC 1995 and 2007 reports respectively. Methane has a more potent impact in the short term, but has a tenfold shorter residence time in the atmosphere than CO2.

Howarth uses a Global Warming Potential for methane of 105 for the 20-year horizon, and 33 for the 100-year timescale. He argues that the 20-year number is appropriate, since global warming must be tackled during this timeframe.

What if Regulators' GWP Conventions Change?

At present, the 21x to 25x factors seem most appropriate. However, an investor might consider a change to this convention as a longer term industry risk. If regulators did shift to using a higher GWP for methane, in an increasingly carbon constrained world, this could impose higher "carbon" costs on fugitive emissions.

In reality, this would presumably increase focus on minimizing fugitive emissions throughout gas operations. New state-of-the-art facilities would presumably be well placed to minimize fugitives.

Appendix A-1

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APPENDIX D

Groundwater Modelling

30 June 2009

QGC GROUNDWATER MODEL

Groundwater Modelling for CSG Extraction - QGC

Submitted to:
BG-QGC Pty Ltd

REPORT

Report Number: 087633050 017 R Rev 2

A world of capabilities delivered locally

Golder Associates

Table of Contents

TABLES

FIGURES

1.0 INTRODUCTION

Queensland Gas Company (QGC) plans to increase its coal seam gas (CSG) fields in the Surat Basin, 200 kilometres west of Brisbane, Queensland. The project involves a major expansion of wells being developed (up to 6,000 production wells) and management, storage and beneficial use of associated water for the expansion.

Golder Associates Pty Ltd (Golder) was commissioned by QGC to examine the effects of the CSG field expansion on the groundwater environment. One part of this project was to develop a hydrogeological model to understand the potential impacts of the project. This report forms Appendix D of the broader QGC Groundwater Study (Golder 087633050 016 R Rev 1).

The aim of this report is to:

- provide input into the risk management strategy being developed for the proposed CSG operations
- make groundwater impact predictions for the current and proposed CSG operations.

1.1 Study Area

The study area encompasses the current QGC development areas, and the proposed CSG development areas in the Surat Basin. It is located on the Darling Downs of Queensland, in an area centred on the towns of Wandoan, Miles, Chinchilla and west of Dalby (Figure 3, in the 087633050 016 document). The CSG development area was divided into three areas, and each area was modelled separately. The three project-defined CSG development areas for the study were defined as the:

- Central Development Area (CDA)
- South East Development Area (SEDA)
- North West Development Area (NWDA).

1.2 Project objectives

The objectives of the modelling program were to:

- Develop an *idealised* regional groundwater model for each development area.
- Interpret the conceptual model and the “order of magnitude” results from the numerical groundwater modelling; and to use those results to estimate the *relative* risks of groundwater impacts arising from the current and proposed CSG operations, and for the post-production period of groundwater recovery.
- Present predictions of expected groundwater drawdown and groundwater extraction volumes associated with proposed CSG operations by QGC in the Surat Basin.
- Develop recommendations for groundwater management and monitoring associated with the QGC CSG operations.

2.0 METHODS

The study area was divided into three areas as outlined in Section 1.7 of the Groundwater Study report. Each of the three areas was considered geologically and hydrogeologically distinct, being delineated by inferred and actual structural breaks. Each area was modelled separately and independently. Therefore, interference effects from the other areas were not considered in the study.

The models were constructed from site specific data provided by QGC. Where site specific information was not available; published sources of information were utilised. The geological and conceptual groundwater model (CGM) developed in Section 4.0 (Description of the existing environment) of the main report were used to develop the numerical models in this report.

MODFLOW was selected as the groundwater model for use in this modelling project. MODFLOW, developed by the United States Geological Survey (USGS), is recognised as an industry standard groundwater flow simulator.

A model had previously been created in September 2008 (Golder 031-077636015/6005-4000 Rev 2). That model was refined, based on QGC's and Australasian Groundwater and Environmental Consultants (AGE) comments. AGE was engaged as the third party reviewer for this study. The results of the new prediction simulations are presented in this report.

2.1 Selection of Groundwater Modelling Software

The software was required to provide several functions. MODFLOW was selected as the modelling software that met the criteria (below). It was processed using Processing MODFLOW for Windows (PMWIN), Version 5.3.0, by Chiang and Kinzelbach. The MODFLOW variant selected within PMWIN was "MODFLOW 96 + INTERFACE TO MT3D96 AND LATER".

The main criteria for selecting the MODFLOW model software were that:

- the software could provide industry standard model code that would not be challenged by NRW or other potential reviewers
- the code had the ability and flexibility to simulate the boundary conditions identified in the conceptualisation
- the model could be adopted for a multi-layering environment
- the model was able to include sufficient definition of aquifer geometry, so that the model could be developed from an initial "simplified model" to a more complex and sophisticated model in the future (if required)
- flexible stress periods and time stepping could be undertaken
- the model was easy to establish and run.

The difference between MODFLOW96 and MODFLOW2000 or MODFLOW2005 relates primarily to the groundwater flow package, namely Block-Centred Flow in MODFLOW96 compared to Layer Property Flow in MODFLOW2000 and onwards. Given this is a simplified model, using only the CHB stress package, the difference in groundwater flow package is not relevant.

3.0 REFINEMENTS FROM THE PREVIOUS MODEL TO THE CURRENT MODEL

An initial preliminary modelling program was undertaken on the centrally located development area, the CDA, and which was reported on separately in "Groundwater Impact Study for the Coal Seam Gas Operations Chinchilla, Surat Basin Queensland" submitted to Queensland Gas Company and Origin Energy (Report 031-077636015/6005-4000 Rev2, dated September 2008). That report identified a number of potentially enhancing refinements which would improve the models estimation.

The improvements that were adopted, were also guided by comments and considerable discussion with QGC hydrogeologists and reservoir engineers, and QGC's appointed third party reviewer, AGE (Mr Errol Briese and Mr Andrew Durick). In summary, the refinements to the current model included:

- The regional dip of 1.3% to the southwest was applied. This added slope to the model layers across the model domain so that they more closely reflect the regional geology. (The previous model was flat)
- Model domains were expanded outward to ensure the boundary conditions had reduced potential to constrain the model outcomes.
- Input parameters were modified on the advice of the AGE reviewers (hydraulic conductivity, vertical to horizontal hydraulic conductivity ratios, storage coefficients and porosity). The ranges of values were generally agreed to be reasonable for the rock-types and this location in the GAB.
- Sequencing of the pumping of the CSG-bearing formations (the Walloon Coal Measures, WCM) to make the modelling approach more closely resemble reality. The model resolution (arising from the broad range of input parameters which could be justifiably used in the modelling) made this subtlety in model design indiscernible and so was not pursued further.
- The thickness and parameter values of the relevant aquitards were modified as more data was received from the QGC drill-stem testing program as well as extended discussion of literature values amongst QGC and AGE.

The original modelling project was conducted on the CDA area only; the current modelling project was conducted on three development areas, the CDA, SEDA and NWDA. Each development area was prepared as a separate and isolated model and did not take into account interference effects from the other models.

The outcome of the current modelling is commensurate with the degree of reliability of the estimate ("order of magnitude"), given the uncertainty of values provided for the model. Ultimately the modelling program's purpose was to develop a risk assessment tool to help define groundwater impact management zones, rather than quantitatively defining groundwater drawdown at specific locations.

4.0 AQUIFER CHARACTERISTICS IN THE STUDY AREA

The information presented in Table 1 for hydraulic conductivity, transmissivity and storage form the basis, upon which the model conceptualisation was prepared. The tabulated information was obtained from:

- available literature
- communication with QGC, and their third party reviewers, AGE
- information provided by NRW; as the authority responsible for managing the Great Artesian Basin (GAB).

Table 1: Aquifer Characteristics in the Study Area

Hydrogeological Unit	Aquifer Name	Hydraulic Conductivity (m/day)	Transmissivity (m^2/day) (1)	Storage (1)	Porosity	Yield (L/s)
Quaternary Aquifers	Shallow Quaternary & Tertiary alluvium (Including the Condamine Alluvium)	Kh - $2.5x10^{-3}$ to $6x10^{-6}$ (average $1.8x10^{-4}$) (2)			10 to 30%(3)	0.1 to 100L/s, median 1.3L/s (5)
Shallow Unit	Main Range Volcanics	0.5 to 50 (6)	10 to 1000 (6)			0.01 to 30 L/s, median 1.7 L/s (5)
	Griman Creek Formation				10 to 30%(3)	3.5L/s (5)
	Wallumbilla Formation		50	$5x10^{-3}$	10 to 30%(3)	
Intermediate Unit	Bungil Formation		50	$5x10^{-3}$	10 to 30%(3)	0.63 to 6.3 L/s (4)
	Mooga Sandstone		50	$5x10^{-3}$	10 to 30%(3)	0.2 to 8 L/s median 1.3L/s (4)
	Orallo Formation		50	$5x10^{-3}$	10 to 30%(3)	0.08 to 2.28 L/s median 1.2L/s (4)
	Gubberamunda Sandstone	Kh - 0.43 to 0.043 (2)	50	$5x10^{-3}$	10 to 30%(3)	1.01 to 22 L/s, median of 4.6L/s (3)
	Kumbarilla Beds					0.03 L/s to 10 L/s, median at 0.8 L/s (4)
Walloon Unit	Westbourne Formation		150	$5x10^{-3}$	10 to 30%(3)	
	Springbok Sandstone		150	$5x10^{-4}$	10 to 30%(3)	
	Walloon Coal Measures	Kh - 1.4 (7) (median for coal beds)	50	$5x10^{-4}$	<1% (8)	0.03 L/s to 19 L/s, median at 1.1 L/s (4)
Hutton Unit	Hutton Sandstone	Kh – 0.1 (9)	150	$5x10^{-4}$	18-26%(10)	0.1 L/s to 600 L/s, median at 1.5 L/s (4)
	Evergreen Formation	Kv - 10^{-1} to 10^{-4} (3)	150	$5x10^{-4}$		0.6 to 6.5 L/s , median 0.6 L/s (4)
Precipice Unit	Precipice Sandstone	0.1 to 10 (10)	150	$5x10^{-4}$	18-20%(10)	0.1 to 30 L/s , median 3.8 L/s (4)

na: data not available for the purpose of the report
Kh hydraulic conductivity in the horizontal (x) direction (or Kx)
Kv hydraulic conductivity in the vertical (z) direction (or Kz)

1: Great Artesian Basin Resource Operation Plan, February 2007
2: QGC, Kenya Pond Groundwater Investigation Report, September 2007
3: Habermehl M.A, 2002, Hydrogeology, Hydrogeochemistry and isotope Hydrology of the Great Artesian basin, Bureau of Rural Sciences
4: NRW database
5: Great Artesian Basin Resource Operation Plan, February 2007
6. Australian Government Department of the Environment and Water Resources - Groundwater Management Unit: Unincorporated Area - Clarence Moreton
7: Previous Groundwater Impact Study data
8: R.A. Freeze, J.A Cherry, 1979, Groundwater
9. Suggested by AGE
10: Provided through previous work in the Surat Basin

5.0 MODEL CONCEPTUALISATION

With the objectives for the modelling study identified in Section 1.2, the key constructs for the models were identified as:

- Three development areas were considered for this modelling study, namely, the NWDA, CDA and SEDA; each constituted a separate and independent model.
- The purpose of modelling was to assess the potential consequences of the extraction of groundwater during liberation of CSG.
- The model domain and input parameters for each model were based on the Conceptual Groundwater Model (CGM) that was developed from available geological and hydrogeological data. The CGM is presented in Section 5.0 of the main report.
- The models were defined as "bathtub" models:
  - The models do not incorporate recharge, and they have not been formally calibrated, as they would in a more detailed and higher resolution modelling project. The absence of long-term groundwater level monitoring data (at this stage) has precluded appropriate calibration to be able to be carried out. It is noted that long term flow data from relevant water courses will also be required to be obtained.
  - A constant head boundary was applied around the external borders (that were appropriately placed to reflect the expected distance outside the depressurisation area that would be unlikely to be influenced by CSG extraction activity).
  - The values for the constant head boundaries for each model were assigned, based on available regional groundwater level data for the three development areas. They were set to be 305 mAHD for the CDA, 295 mAHD for the NWDA and 315 mAHD for the SEDA.
- Each model was constructed as a rectangular strip running parallel to the regional strike of the geology. Each model was established with a total length of 144 km, including 50 km of CSG activities (extraction area, referred to as the depressurisation area), and a width of 120 km, including 10 km of CSG activities. The model domains were positioned so that the CSG extraction activities were located in the centre of each model area.
- Given the stratigraphy of the model is sloped and the model extent is significant, it was necessary to assign fixed head boundary conditions so that they were above the bottom of individual cells.
- The layer thicknesses in each model were set, based on the stratigraphy in each development area.
- The depressurisation area, the idealised representation of QGC production areas (tenements/lease, current and proposed) of each model, was considered as one single area with time-varying-specified-heads used to simulate the proposed pumping schedule of the project area. The effect of sequential pumping different sub-areas within the overall production area was found to be indiscernible at the resolution of the current model.
- The elevation of each layer was made flat within each individual development area, as a simplification, prior to applying the time-varying-specified-head boundary conditions.
- The CSG extraction *depressurisation schedules* for the defined piezometric heads (lying within the defined depressurisation area) in the Walloon Coal Measure (WCM) 'aquifer' layers were provided by QGC. As described in the preceding bullet point, this was simplistically simulated by having the modelled piezometric head 'dragged' down in the model's central area (to represent the operation areas in the central portion of the model domains) according to the depressurisation timeframes as a method to simulate the groundwater extraction over time.

6.0 MODEL CONSTRUCTION

Each model was defined with 18 layers, 272 columns and 234 rows; the same model structure was adopted for each model. The nominal dimensions of cells representing the well field area in each model were 250 m by 250 m, increasing in width beyond the well field with an expansion factor of 1.5 towards the edges. The model dimensions were 144 km long (NW-SE direction) by 120 km wide (NE-SW direction). Within this rectangle, each CSG well field was represented by a central rectangle of 50 km by 10 km; each area being larger than the likely extent of the CSG development area.

The layouts for each modelled CSG development area are presented in Figures D-1 to D-3. These areas each represent an idealised CSG extraction field, crudely representative of the distributed existing and potential future (ATPs) petroleum leases from which QGC propose to extract CSG.

Layers were assigned in accordance with known aquifer or aquitard units, and their elevations were calculated according to the CGM presented in the main report. The thicknesses of each of these layers were assumed to be constant throughout the model, which is a simplification. Layers in the model were dipped in a south west direction, as described above.

Each model domain comprised the Intermediate, Walloon, Hutton and Precipice aquifer units. Layer 1 of the model represents the shallow, unconfined aquifers near the surface. This typically represents the Quaternary or Shallow GAB aquifers, where present in the area of the CSG well field development. An impermeable basement was assumed to exist below the Precipice Formation (which is a conservative assumption). Table 2 presents the layer elevation and thicknesses of the CDA, SEDA and NWDA models. Note that the Top and Bottom elevations presented in Table 2 are with respect to the centre of each model (NE-SW direction).

Table 2: Layer Elevations and Thicknesses

			CDA			SEDA			NWDA		
Layer Number	**Description**	**Modelled Unit**	**Top**	**Bot**	***Thk***	**Top**	**Bot**	***Thk***	**Top**	**Bot**	***Thk***
1	Aquifer	Unconfined Shallow / Intermediate Unit	319	301	*18*	350	320	*30*	350	310	*40*
2	Aquifer	Intermediate Unit	301	283	*18*	320	290	*30*	310	270	*40*
3	Aquifer	Intermediate Unit	283	265	*18*	290	260	*30*	270	230	*40*
4	Aquifer	Intermediate Unit	265	247	*18*	260	230	*30*	230	190	*40*
5	Aquitard	Confining unit	247	229	*18*	230	200	*30*	190	150	*40*
6	Aquifer	Intermediate Unit	229	211	*18*	200	115	*85*	150	75	*75*
7	Aquitard	Westbourne Formation	211	106	*105*	115	0	*115*	75	-105	*180*
8	Aquifer	Springbok	106	66	*40*	0	-75	*75*	-105	-208	*103*
9	Aquitard	Confining unit	66	56	*10*	-75	-105	*30*	-208	-218	*10*
10	Aquifer	Upper representative Coal Seam	56	46	*10*	-105	-115	*10*	-218	-228	*10*
11	Aquitard	Confining unit	46	-272	*318*	-115	-255	*140*	-228	-408	*180*
12	Aquifer	Lower representative Coal Seam	-272	-282	*10*	-255	-295	*40*	-408	-418	*10*
13	Aquitard	Confining unit	-282	-382	*100*	-295	-395	*100*	-418	-468	*50*
14	Aquifer	Hutton Sandstone	-382	-461	*79*	-395	-473	*78*	-468	-543	*75*
15	Aquifer	Hutton Sandstone	-461	-540	*79*	-473	-551	*78*	-543	-618	*75*
16	Aquifer	Hutton Sandstone	-540	-619	*79*	-551	-629	*78*	-618	-693	*75*
17	Aquitard	Evergreen Formation	-619	-788	*169*	-629	-799	*170*	-693	-863	*170*
18	Aquifer	Precipice Formation	-788	-851	*63*	-799	-861	*62*	-863	-924	*61*

Note: Top is Top Elevation (mAHD); Bot is Bottom Elevation (mAHD); and *Thk* is Thickness (m). It is noted that Top and Bottom elevations are with respect to the centre of each model (NE-SW direction).

Coal seam gas is typically extracted from a number of coal seams in the upper Walloon Coal Measures (WCM), however, gas is also extracted from a few deeper seams, located below the Tangalooma Sandstone within the WCM. Accordingly, in the model, the WCM was assumed to be confined by upper and lower bounding aquitards (Layer 9 and 13). The upper WCM coal seams were represented by Layer 10 within the model and the lower seams (Taroom Coal Measures) were represented by Layer 12. Layer 11 was assumed to be an aquitard between the extraction zones. This aquitard represents mudstones, shales and sandstones (i.e. Tangalooma Sandstone) within the study area.

The aquitard above the coal seams (Layer 9) represents a thin layer of mudstone, siltstone and coal, as CSG wells are typically screened below the Kogan coal seam. The bottom aquitard (Layer 13) is about 10 times thicker than the upper aquitard and separates the Taroom Coal Measures (Lower Seam) from the Eurombah Formation and the Durambilla Formation.

A constant head boundary condition was assigned around the outside of each model domain. Based on the interpretation of regional geology within each area, the constant head cells in the northeast section of the model domain were adjusted as appropriate, for the uppermost layers, so that the prescribed head (mAHD) was above the defined base of the corresponding model cell. Total head in an aquifer is the sum of the elevation head and the pressure head. In a CSG well undergoing pumping, the pressure head is equal to the pressure exerted by the fluid level inside in the well, and the casing pressure from methane gas. Based on this assumption, the starting total head in the WCM aquifers was estimated to be equal to about 305 m AHD over the central part of the CDA, which is also very close to, or often the same as, the aquifer pressure in overlying and underlying sandstone aquifers. This value was adopted as the starting head for the CDA model. The initial heads of the NWDA and the SEDA were adopted as 295 m AHD and 315 m AHD respectively, based on an average of measured groundwater levels in those areas.

The centrally located *depressurisation area* of the models (regarded in this modelling study as the *idealised representation* of QGC production areas, i.e. the QGC tenements/lease, current and proposed), were considered as one single area with time-varying-specified-heads used to simulate the proposed pumping schedule of each project area. To assess the affect of sequencing the pumping of the CSG-bearing formations WCM over time, the centrally located depressurisation area was subdivided into four quadrants, each starting and stopping production in accordance with the general plan of production proposed by QGC. It was found, however, that the model resolution (given the broad range of input parameters that could be justifiably used in the modelling) made this subtlety in model design indiscernible. As such, further attempts at sequencing were not made.

Dewatering of each of the three development areas was conducted in accordance with QGC's proposed production schedule. It is planned that 50% depressurisation will occur within the first four to seven years of production. Residual depressurisation of the WCM, to a target of between 150 psi (~100 m above the top of the WCM aquifer) and 50 psi (~35 m above the top of the WCM aquifer), is proposed to continue from year 7 to year 40 (the end of well field production life). The adopted depressurisation curves for CDA, SEDA and NWDA are presented in Figures D-4 to D-6. At the end of the well field production life, each model was allowed to recovery for the next 150 years. Table 3 presents a summary of the depressurisation adopted in this modelling exercise.

Table 3: Generalised Depressurisation Schedule

Modelled Years	Stress Periods	Remarks
0 to 40	17	Depressurisation pumping of lower & upper coal seam groups (simulating groundwater pumping from Walloons aquifers from CSG well field)
40 to 190	18	Depressurisation pumping terminates, CSG extraction complete, and aquifer recovery begins.

Each groundwater model was developed based on the assumption of single-phase flow of groundwater in porous media. Therefore, an implicit assumption is that gas and water within the WCM are validly represented by the adopted governing equation. In reality, there may be areas where gas and water exist as two separate phases. In that case, the application of a single-phase groundwater model code such as MODFLOW, to a multi-phase problem, may introduce further uncertainty to model predictions. This is considered acceptable at this level of modelling (low resolution) for the following reasons:

- The change in permeability brought about by the progressive formation of a CSG gas 'bubble' in the pore spaces in the coal, as desorption begins in earnest, constrains ('throttles back') the flow of *groundwater* to the CSG well. This can be considered as imposing a reduction in the *effective* hydraulic conductivity on the coal seam aquifers.

- The predicted future associated water production curves have been calculated from actual production data provided by QGC current productions wells. The curves have the reduction of hydraulic conductivity (described above) in the coal seams, where gas generation and extraction is taking place built into them. Beyond the desorption 'front' (away from the well field and towards the lease boundary) where gas generation is not occurring, the drawdown cone is defined by the standard theory of groundwater flow. i.e. based on an extraction rate (Q) being actually pumped from the well.

In summary, the model is a reasonable approximation of the drawdown impacts because:

a) The relationship between the actual quantity of groundwater extracted from the coal seam aquifer/s (beyond the coal desorption front) and the drawdown (piezometric head decline) is fixed, as per the standard theory of groundwater flow. The introduction of a gas phase merely constrains the flow of water to the CSG well screens from the aquifer (locally lowering the hydraulic conductivity with respect to water flow) where pressure conditions are low enough for gas desorption/ generation. Beyond that, and away from the edge of the production field, groundwater flow within the models are based on the actual groundwater being extracted.

b) The cone of drawdown is of primary interest for developing a risk management strategy (in relation to the groundwater impacts to surrounding aquifers and the groundwater users exploiting them) and is governed largely by the actual groundwater extracted.

The numerical models approximate (b) with reasonable certainty (to "order of magnitude" resolution), accepting that there is limited available hydrogeological parameters (range of K, S, T and ϕ), used for the numerous aquifers and aquitards that comprise the stratigraphy (and encase the CSG containing seams) in the study area.

This modelling study has applied *ranges* of K values, Kv/Kh and S values (in the absence of site specific data that are applicable to the local lithologies. This was based on evidence from the literature for GAB data and generic data for specific rock types). It was considered that any deviation from rigid predictions of two-phase flow, and associated drawdown profiles and inter-aquifer flow, would not be significant in the context of the range of predicted outcomes (estimation of impacts from CSG extraction) provided by the modelling results.

7.0 MODEL SIMULATION METHODOLOGY

At this stage, a long term regional groundwater level time-series is *not* available to allow formal model calibration. Currently, there is also limited information from test pumping of the WCM aquifer, regionally, and other important hydrogeological units; therefore selected model simulation parameter sets are non-unique.

There were, however, detailed predictions available from QGC reservoir engineers that were developed using standard reservoir engineering methodologies for calculation of required gas and groundwater production rates from the reservoir materials concerned. Those predictions reflect QGC's expectation of the inter-relationship between pressure decline and expected gas and associated water production and were developed based on an assessment of currently installed and producing CSG wells, as discussed below.

Because the purpose of producing predictions of drawdown was to provide input into the risk management strategy to be adopted for the CSG operations, rather than an absolute and quantitative prediction of drawdown magnitude at specific locations (at this stage), QGC's estimates of groundwater extraction (associated water production) with respect to pressure decline were used to frame multiple simulation scenarios, ultimately bounded by a modelled *potential minimum parameter set*; and a *modelled potential maximum parameter set*.

Since groundwater extraction (total volumetric extraction rate) is a key consideration in assessing the validity of the modelling process, it is important to understand and have confidence in the methodology used to estimate the QGC associated water production rate figures. QGC have provided their methodology as follows (John Bailey, QGC, email 19 February 2009):

> *"The water production schedule was initially derived from an assessment of currently installed and producing wells (many of which have been producing for 2+ years, and therefore represent a satisfactorily long statistic) which have been classified into categories according to their gas yield - Type 1 (high yielding wells), Type 2 (intermediate yielding wells) and Type 3 (low yielding wells) and Type 4 (low gas high water wells). Each type has an assumed profile for associated water production correlated to their peak gas production rate. This data set of well categories was then applied to the QGC tenements - with Type 1, 2 , 3 and 4 wells being locally applied in accordance with known or predicted information about reservoir performance variability across the proposed development area. In this way QGC was able to build up a schedule of production based on 2203 Type 1 wells, 2935 Type 2 wells, 750 Type 3 wells and 265 Type 4 wells. Estimated areal production rates reflect these Well type production rates over a 30 year period from initial production. The ongoing production testing and appraisal programme during 2009/2010 will progressively increase the confidence in the water production forecasts, but at this time an uncertainty band of +/- 50% should be assumed."*

The depressurisation schedule estimates (extraction rates, inclusive of the ±50% accuracy provision, as defined by QGC) were used as the basis to align a range of model scenarios (generated by varying input parameters of hydraulic conductivity, Kv/Kh ratios and storativity values) that produced outputs of associated water volumes that bounded (bracketed or enveloped) the QGC predicted associated water production figures. That is, the process of model "calibration" has required a range of model input parameters (considered realistic for the hydrostratigraphy) to be used to estimate a range of groundwater piezometric head drawdowns that can be used to assess potential impacts. Iterative methods were used to ……. until the modelled extraction rate approximately matched the range of QGC predicted extraction rates (depressurisation schedule).

The simulation iterations involved varying hydraulic parameters within realistic ranges (determined as being the realistic minimum and maximum for each of the aquifer and aquitard units) based on the available limited published and site specific data. Ratios of vertical hydraulic conductivity versus horizontal hydraulic conductivity (refer to as Kv/Kh ratios) of between 1:10 and 1:1000 considered appropriate for various layers in the model, with 1:500 and 1:1000 considered most particular to the coal and finer grained (mudstones and siltstones) members of the hydrostratigraphy (i.e. the aquitards) for this modelling study. Model groundwater extraction rates were then calculated by the model for the 40 years of wellfield operations, followed by 150 years of recovery (non-pumping). The consideration that 150 years was sufficient to provide an indication of how the groundwater system would recover after the CSG extraction operations were completed was nominal and is only considered a crude approximation of the recovery phase. Progressive wellfield monitoring of this process will be the only way to show how recovery is progressing. Ongoing iterations of the model or its replacement will be required to verify recovery progress.

On this basis, the modelled potential minimum parameter set and modelled potential maximum parameter set used in each model area are presented in Table 4, Table 5 and Table 6 for CDA, SEDA and NWDA respectively.

Table 4: Model hydraulic Parameters- Modelled Potential Maximum and Minimum Parameter Sets for CDA

Layer Number	Description	Modelled Unit	Modelled Potential Maximum Parameter Set				Modelled Potential Minimum Parameter Set			
			Kh (m/day)	Kv (m/day)	Kh/Kv	Storativity (S)	Kh (m/day)	Kv (m/day)	Kh/Kv	Storativity (S)
1	Aquifer	Intermediate Unit	3.60E-02	7.20E-03	5	1.00E-03	3.60E-03	7.20E-04	5	5.00E-04
2	Aquifer	Intermediate Unit	3.60E-02	7.20E-03	5	5.00E-03	3.60E-03	7.20E-04	5	5.00E-04
3	Aquifer	Intermediate Unit	3.60E-02	7.20E-03	5	5.00E-03	3.60E-03	7.20E-04	5	5.00E-04
4	Aquifer	Intermediate Unit	3.60E-02	7.20E-03	5	5.00E-03	3.60E-03	7.20E-04	5	5.00E-04
5	Aquitard	Confining unit	3.60E-03	7.20E-03	<1	5.00E-03	3.60E-04	7.20E-05	5	5.00E-04
6	Aquifer	Intermediate Unit	3.60E-01	7.20E-03	50	5.00E-03	3.60E-02	7.20E-04	50	5.00E-05
7	Aquitard	Westbourne Formation	1.00E-03	2.00E-05	50	5.00E-04	1.00E-04	2.00E-06	50	5.00E-05
8	Aquifer	Springbok	1.25E+00	2.50E-02	50	5.00E-04	1.25E+00	2.50E-02	50	5.00E-05
9	Aquitard	Confining unit	2.50E-03	5.00E-06	500	5.00E-04	2.50E-04	5.00E-07	1000	5.00E-05
10	Aquifer	Upper Representative Coal Seam	1.36E+00	4.53E-01	3	5.00E-04	1.40E-02	4.67E-03	3	5.00E-05
11	Aquitard	Confining unit	5.00E-03	1.00E-05	500	5.00E-04	5.00E-04	1.00E-06	1000	5.00E-05
12	Aquifer	Lower Representative Coal Seam	1.36E+00	4.53E-01	3	5.00E-04	1.40E-02	4.67E-03	3	5.00E-05

Layer Number	Description	Modelled Unit	Modelled Potential Maximum Parameter Set				Modelled Potential Minimum Parameter Set			
			Kh (m/day)	Kv (m/day)	Kh/Kv	Storativity (S)	Kh (m/day)	Kv (m/day)	Kh/Kv	Storativity (S)
13	Aquitard	Confining unit	2.50E-03	5.00E-06	500	5.00E-04	2.50E-04	5.00E-07	1000	5.00E-05
14	Aquifer	Hutton Sandstone	1.00E-01	1.40E-02	7	5.00E-04	1.00E-02	1.43E-03	7	5.00E-05
15	Aquifer	Hutton Sandstone	1.00E-01	1.40E-02	7	5.00E-04	1.00E-02	1.43E-03	7	5.00E-05
16	Aquifer	Hutton Sandstone	1.00E-01	1.40E-02	7	5.00E-04	1.00E-02	1.43E-03	7	5.00E-05
17	Aquitard	Evergreen Formation	1.00E-02	2.00E-04	50	5.00E-04	1.00E-04	2.00E-06	1000	5.00E-05
18	Aquifer	Precipice Formation	3.80E+00	1.01E-01	38	5.00E-04	1.00E-01	2.63E-03	38	5.00E-05

Table 5: Model hydraulic Parameters- Modelled Potential Maximum and Minimum Parameter Sets for SEDA

Layer Number	Description	Modelled Unit	Modelled Potential Maximum Parameter Set				Modelled Potential Minimum Parameter Set			
			Kh (m/day)	Kv (m/day)	Kh/Kv	Storativity (S)	Kh (m/day)	Kv (m/day)	Kh/Kv	Storativity (S)
1	Aquifer	Intermediate Unit	3.60E-02	7.20E-03	5	1.00E-03	3.60E-03	7.20E-04	5	5.00E-04
2	Aquifer	Intermediate Unit	3.60E-02	7.20E-03	5	5.00E-03	3.60E-03	7.20E-04	5	5.00E-04
3	Aquifer	Intermediate Unit	3.60E-02	7.20E-03	5	5.00E-03	3.60E-03	7.20E-04	5	5.00E-04
4	Aquifer	Intermediate Unit	3.60E-02	7.20E-03	5	5.00E-03	3.60E-03	7.20E-04	5	5.00E-04
5	Aquitard	Confining unit	3.60E-03	7.20E-04	5	5.00E-03	3.60E-04	7.20E-05	5	5.00E-04
6	Aquifer	Intermediate Unit	3.60E-01	7.20E-03	50	5.00E-03	3.60E-02	7.20E-04	50	5.00E-05
7	Aquitard	Westbourne Formation	1.00E-03	2.00E-05	50	5.00E-04	1.00E-04	2.00E-06	50	5.00E-05
8	Aquifer	Springbok	1.25E+00	2.50E-02	50	5.00E-04	1.25E+00	2.50E-02	50	5.00E-05
9	Aquitard	Confining unit	1.25E-03	2.50E-06	500	5.00E-04	2.50E-04	5.00E-07	500	5.00E-05
10	Aquifer	Upper Representative Coal Seam	1.95E-01	6.50E-02	3	5.00E-04	1.40E-03	4.67E-04	3	5.00E-05

Layer Number	Description	Modelled Unit	Modelled Potential Maximum Parameter Set				Modelled Potential Minimum Parameter Set			
			Kh (m/day)	Kv (m/day)	Kh/Kv	Storativity (S)	Kh (m/day)	Kv (m/day)	Kh/Kv	Storativity (S)
11	Aquitard	Confining unit	2.50E-03	5.00E-06	500	5.00E-04	5.00E-04	1.00E-06	500	5.00E-05
12	Aquifer	Lower Representative Coal Seam	1.95E-01	6.50E-02	3	5.00E-04	1.40E-03	4.67E-04	3	5.00E-05
13	Aquitard	Confining unit	1.25E-03	2.50E-06	500	5.00E-04	2.50E-04	5.00E-07	500	5.00E-05
14	Aquifer	Hutton Sandstone	1.00E-01	1.40E-02	7	5.00E-04	1.00E-02	1.43E-03	7	5.00E-05
15	Aquifer	Hutton Sandstone	1.00E-01	1.40E-02	7	5.00E-04	1.00E-02	1.43E-03	7	5.00E-05
16	Aquifer	Hutton Sandstone	1.00E-01	1.40E-02	7	5.00E-04	1.00E-02	1.43E-03	7	5.00E-05
17	Aquitard	Evergreen Formation	1.00E-02	2.00E-04	50	5.00E-04	1.00E-04	2.00E-06	1000	5.00E-05
18	Aquifer	Precipice Formation	3.80E+00	1.01E-01	38	5.00E-04	1.00E-01	2.63E-03	38	5.00E-05

Table 6: Model hydraulic Parameters- Modelled Potential Maximum and Minimum Parameter Sets for NWDA

Layer Number	Description	Modelled Unit	Modelled Potential Maximum Parameter Set				Modelled Potential Minimum Parameter Set			
			Kh (m/day)	Kv (m/day)	Kh/Kv	Storativity (S)	Kh (m/day)	Kv (m/day)	Kh/Kv	Storativity (S)
1	Aquifer	Intermediate Unit	3.60E-02	7.20E-03	5	1.00E-03	3.60E-03	7.20E-04	5	5.00E-04
2	Aquifer	Intermediate Unit	3.60E-02	7.20E-03	5	5.00E-03	3.60E-03	7.20E-04	5	5.00E-04
3	Aquifer	Intermediate Unit	3.60E-02	7.20E-03	5	5.00E-03	3.60E-03	7.20E-04	5	5.00E-04
4	Aquifer	Intermediate Unit	3.60E-02	7.20E-03	5	5.00E-03	3.60E-03	7.20E-04	5	5.00E-04
5	Aquitard	Confining unit	3.60E-03	7.20E-03	<1	5.00E-03	3.60E-04	7.20E-05	5	5.00E-04
6	Aquifer	Intermediate Unit	3.60E-01	7.20E-03	50	5.00E-03	3.60E-02	7.20E-04	50	5.00E-05
7	Aquitard	Westbourne Formation	1.00E-03	2.00E-05	50	5.00E-04	1.00E-04	2.00E-06	50	5.00E-05
8	Aquifer	Springbok	1.25E+00	2.50E-02	50	5.00E-04	1.25E+00	2.50E-02	50	5.00E-05
9	Aquitard	Confining unit	7.57E-05	1.15E-07	500	5.00E-04	2.50E-05	5.00E-08	500	5.00E-05
10	Aquifer	Upper Representative Coal Seam	4.12E-02	1.37E-02	3	5.00E-04	1.40E-03	4.67E-04	3	5.00E-05

Layer Number	Description	Modelled Unit	Modelled Potential Maximum				Modelled Potential Minimum			
			Parameter Set				Parameter Set			
			Kh (m/day)	Kv (m/day)	Kh/Kv	Storativity (S)	Kh (m/day)	Kv (m/day)	Kh/Kv	Storativity (S)
11	Aquitard	Confining unit	1.15E-04	3.03E-07	380	5.00E-04	5.00E-05	1.00E-07	500	5.00E-05
12	Aquifer	Lower Representative Coal Seam	4.12E-02	1.37E-02	3	5.00E-04	1.40E-03	4.67E-04	3	5.00E-05
13	Aquitard	Confining unit	7.57E-05	1.15E-07	500	5.00E-04	2.50E-05	5.00E-08	500	5.00E-05
14	Aquifer	Hutton Sandstone	1.00E-01	1.40E-02	7	5.00E-04	1.00E-02	1.43E-03	7	5.00E-05
15	Aquifer	Hutton Sandstone	1.00E-01	1.40E-02	7	5.00E-04	1.00E-02	1.43E-03	7	5.00E-05
16	Aquifer	Hutton Sandstone	1.00E-01	1.40E-02	7	5.00E-04	1.00E-02	1.43E-03	7	5.00E-05
17	Aquitard	Evergreen Formation	1.00E-02	2.00E-04	50	5.00E-04	1.00E-04	2.00E-06	1000	5.00E-05
18	Aquifer	Precipice Formation	3.80E+00	1.01E-01	38	5.00E-04	1.00E-01	2.63E-03	38	5.00E-05

8.0 MODEL RESULTS

8.1 Predicted Drawdown

8.1.1 Results of CDA Modelling

The model was run for the potential maximum and potential minimum parameter datasets. The predicted drawdown envelope for the Springbok, Hutton and Precipice Sandstones are presented in Figure D-7.

The model was executed for 40 years of depressurisation, followed by 150 years of recovery with no pumping. From Figure D-7, the modelled potential maximum parameter set is associated with the maximum predicted drawdown, and the modelled potential minimum parameter dataset is associated with the minimum predicted drawdown, for the CDA. For the modelled potential maximum parameter dataset, drawdown in the Springbok Sandstone is predicted to reach about 55 m at a distance of 1.8 km from the south east edge of the depressurisation zone. Recovery of the aquifer is predicted to commence immediately after pumping terminates (40 years). Figure D-7 indicates that the predicted maximum drawdown is about 2.5 m in the Hutton Sandstone and that recovery is predicted to commence about 50 years after pumping terminates (90 years). The maximum predicted drawdown of the Precipice Sandstone is about 1.8 m. Recovery of the Precipice Sandstone is predicted to commence at about 60 years after pumping terminates (100 years).

The predicted drawdown from the centre of the depressurisation area, in a southeast direction, for Year 10, 25 and 40 for the Gubberamunda Sandstone, Springbok Sandstone, Hutton Sandstone and Precipice Sandstone is presented in Figures D-8 to D-11. As expected, the maximum predicted drawdown occurs in the Coal Seams and the Springbok Sandstone aquifers. The high drawdown in the Springbok aquifer is due to a high induced downward gradient between the Springbok and Walloon Coal Measures that are separated by a thin aquitard. Similarly, the lower aquifer units (Hutton and Precipice) are separated by a thicker aquitard unit, which reduces the upward connectivity (flow) into the lower WCM seam. Throughout the simulation, the predicted aquifer drawdown in the Intermediate Unit (Mooga, Oralla, and Gubberamunda Sandstone) was minimal.

Figure D-9 indicates that the modelled maximum drawdown within the Springbok Sandstone, near the centre of the depressurisation area, could vary between 10 m and 85 m. The drawdown also decreases continuously away from the centre of the depressurisation area.

8.1.2 Results of SEDA Modelling

The model was run for the potential maximum and minimum parameter datasets for the SEDA. The predicted drawdown envelopes for the Springbok, Hutton and Precipice Sandstones are presented in Figure D-12.

As expected for the SEDA, the modelled potential maximum parameter set is associated with the maximum predicted drawdown, and the modelled potential minimum parameter dataset is associated with the minimum predicted drawdown. For the modelled potential maximum parameter dataset, drawdown in the Springbok Sandstone is predicted to reach about 23 m at a distance of 1.8 km, in a southeast direction, from the edge of the depressurisation zone. Recovery of the aquifer is predicted to commence 5 years after pumping terminates (45 years). The model predicts that drawdown in the Hutton Sandstone may reach about 8 m (Figure D-12). The model indicates that recovery of the Hutton Sandstone is predicted to commence about 15 years after pumping terminates (55 years). The maximum modelled drawdown for the Precipice Sandstone is about 6 m for the simulation, considering the potential maximum model parameter dataset. The modelled recovery for the Precipice Sandstone is predicted to begin at about 25 years after pumping terminates (65 years).

The predicted maximum drawdown in the Springbok Sandstone in the SEDA is less than the CDA. This is because the SEDA has a thicker aquitard unit between the Springbok and the Upper Coal Seam Unit, compared to the CDA. The higher drawdown predicted for the Hutton and Precipice Sandstone in the SEDA model, compared to the CDA, is likely to be due to the larger drawdown required for the WCM in the SEDA

(1 m versus 180 m in the CDA). Therefore pumping from the WCM will potentially generate more impact in deeper aquifers such as the Hutton and Precipice Sandstone aquifers.

The predicted drawdown for the Gubberamunda Sandstone, Springbok Sandstone, Hutton Sandstone and Precipice Sandstone is presented in Figures D-13 to D-16. The drawdown is from the centre of the depressurisation area in a southeast direction for Years 10, 25 and 40.

Figure D-14 indicates that the modelled drawdown within the Springbok Sandstone could vary between approximately 2 m and 36 m, near the centre of the depressurisation area after 40 years of pumping. Again, drawdown continuously decreases away from the centre of the depressurisation area.

8.1.3 Results of NWDA Modelling

The model was run for the potential maximum and potential minimum parameter datasets for the NWDA. The predicted drawdown envelope for the Springbok, Hutton and Precipice Sandstones are presented in Figure D-17.

For the NWDA, (Figure D-17), the modelled potential maximum parameter set is associated with the maximum predicted drawdown and the modelled potential minimum parameter dataset is associated with the minimum predicted drawdown. For the modelled potential maximum parameter dataset, drawdown in the Springbok Sandstone is predicted to reach about 2 m at a distance of 1.8km from the edge of the depressurisation zone. Recovery of the aquifer is predicted to commence 75 years after pumping terminates (115 years). Figure D-17 indicates that the predicted maximum drawdown in the Hutton Sandstone and the Precipice Sandstone is insignificant.

The predicted drawdown for the Springbok Sandstone is presented in Figure D-18. The drawdown is from the centre of the depressurisation area, in a southeast direction, for Years 10, 25 and 40.

Figure D-18 indicates that the modelled maximum drawdown within the Springbok Sandstone could vary between less than 0.5 m and approximately 2 m, near the centre of the depressurisation area. Drawdown, again, continuously decreases away from the centre of the depressurisation area.

8.2 Predicted Water Budget

The model simulated total extraction rates for the Upper and Lower Coal Seams for the CDA, SEDA and NWDA (Figure D-19 to D-21). In Figure D-19 to D-21, the shape of the modelled groundwater extraction rate follows the reciprocal of the time-varying-specified-head boundary condition applied to the CDA, NWDA and SEDA. The time-varying-specified head boundary conditions are presented in Figure D-4 to D-6. The expected extraction rates, supplied by QGC, for each development area, are also provided for comparison. It is noted that the model mass balance error was checked for each numerical simulation prior to extracting the results.

From Figure D-19 to D-21, the extraction rate is predicted to rapidly increase during the first 4 to 7 years, and then gradually decline to the end of the simulation for the CDA, NWDA and SEDA. This generally matches the expected extraction rates provided by QGC with respect to the NWDA and SEDA, however, the expected peak extraction for the CDA is 20 years whereas in Figure D-19, the model simulation indicates it may occur earlier.

The predicted groundwater extractions from the WCM (Layers 10 and 12), for the three modelled areas at Year 40, are presented in Table 7, with the equivalent expected extraction rate provided by QGC.

The predicted gradient-induced transfer of groundwater from the Springbok (Layer 8), Hutton Sandstone (Layer 14) and Precipice Sandstone (Layer 18) are presented in Table 8 for *Year 40* (nominally).

Table 7: Predicted Groundwater Extraction Rate at *Year 40*

Modelled Area	Extraction Rate - Modelled Potential Maximum Parameter Set (ML/day)	Extraction Rate - Modelled Potential Minimum Parameter Set (ML/day)	QGC Expected Extraction Rate (ML/day)
	WCM*	WCM*	WCM*
CDA	96.0	9.4	15.2
SEDA	70.7	10.8	6.7
NWDA	17.7	4.2	0.5

where WCM is Walloon Coal Measures, SPG is Springbok, HS is Hutton Sandstone and PS is Precipice Sandstone;

* Note that WCM is the aquifer being pumped.

Table 8: Predicted rate of groundwater transfer from Springbok Formation, Hutton Sandstone and Precipice Sandstone at *Year 40*

Modelled Area	Volumetric Transfer - Modelled Potential Maximum Parameter Set (ML/day)[a]			Volumetric Transfer - Modelled Potential Minimum Parameter Set (ML/day)[a]		
	SPG	HS[b]	PS	SPG	HS[b]	PS
CDA	56.8	17.1	10.2	4.8	<0.1	<0.1
SEDA	27.0	12.4	7.1	0.8	<0.1	<0.1
NWDA	2.9	<0.1	<0.1	0.3	<0.1	<0.1

where SPG is Springbok, HS is Hutton Sandstone and PS is Precipice Sandstone.

[a] The transfer rates reported for SPG, HS and PS reflect internal movement of water out of these aquifers;

[b] The volumetric transfer rate reported for HS is from Layer 14 only and represents transfer from Hutton Sandstone upward.

9.0 MODEL LIMITATIONS

The limitations of the model are:

- The model provides a simplified representation of actual conditions, with homogeneous isotropic conditions within the model layers and assumptions related to the applied constant head boundaries.
- The models have not been formally calibrated due to the absence of appropriate long-term groundwater level monitoring data and the absence of quantitative information on the amount of rainfall recharge occurring to areas where significant aquifers outcrop at ground surface.
- The model applies average (bulk) hydraulic parameters for the layers, however in reality, there is likely to be variability in hydraulic parameters within the model domain.
- The potential influence of residual drawdown from previous activities is uncertain because the three development areas were modelled independently.
- The model did not consider the influence that may occur from other neighbouring CSG extraction operations.
- The sophistication of model predictions is necessarily limited because the extent of information available on the hydraulic properties of the various hydrogeological units is limited.

10.0 RECOMMENDATIONS

To improve the model in the future, the following recommendations are provided:

- The current model is appropriately simple and it can be improved by increasing the density of the dataset upon which it is based. The simplicity of the current model is due to the lack of, and quality of, available data. The geometry of the model domain, for example, could be evaluated in more detail in a future modelling exercise.

- The number of model layers may be able to be reduced to 13 layers (and perhaps even less), based on layer thicknesses and applied hydraulic parameters for current model.

- Once appropriate calibration data is available, a single model for all three development areas should be considered. A combined model could then predict the expected drawdown influences occurring between development areas, however, influences from neighbouring CSG activities also need to be considered.

- The current model has not been calibrated for regional steady state or transient state simulations. The model could be calibrated for rainfall recharge if historical groundwater level data were available. More importantly, the model could be extended to the northeast, to include the area where the sandstone aquifers outcrop at ground surface and where potential rainfall recharge may occur into the deeper aquifers. Another calibration dataset will become available from the results of the monitoring program associated with the existing CSG activities.

- Establishing a long-term groundwater monitoring program for selected bores from different aquifers is important. Installing automated data loggers for groundwater level monitoring in selected bores is strongly recommended. This data could be incorporated into future modelling activities.

- Conducting a pumping test program to estimate hydraulic parameters for every aquifer is vital. This data would provide a solid foundation for increasing the confidence in model predictions.

Report Signature Page

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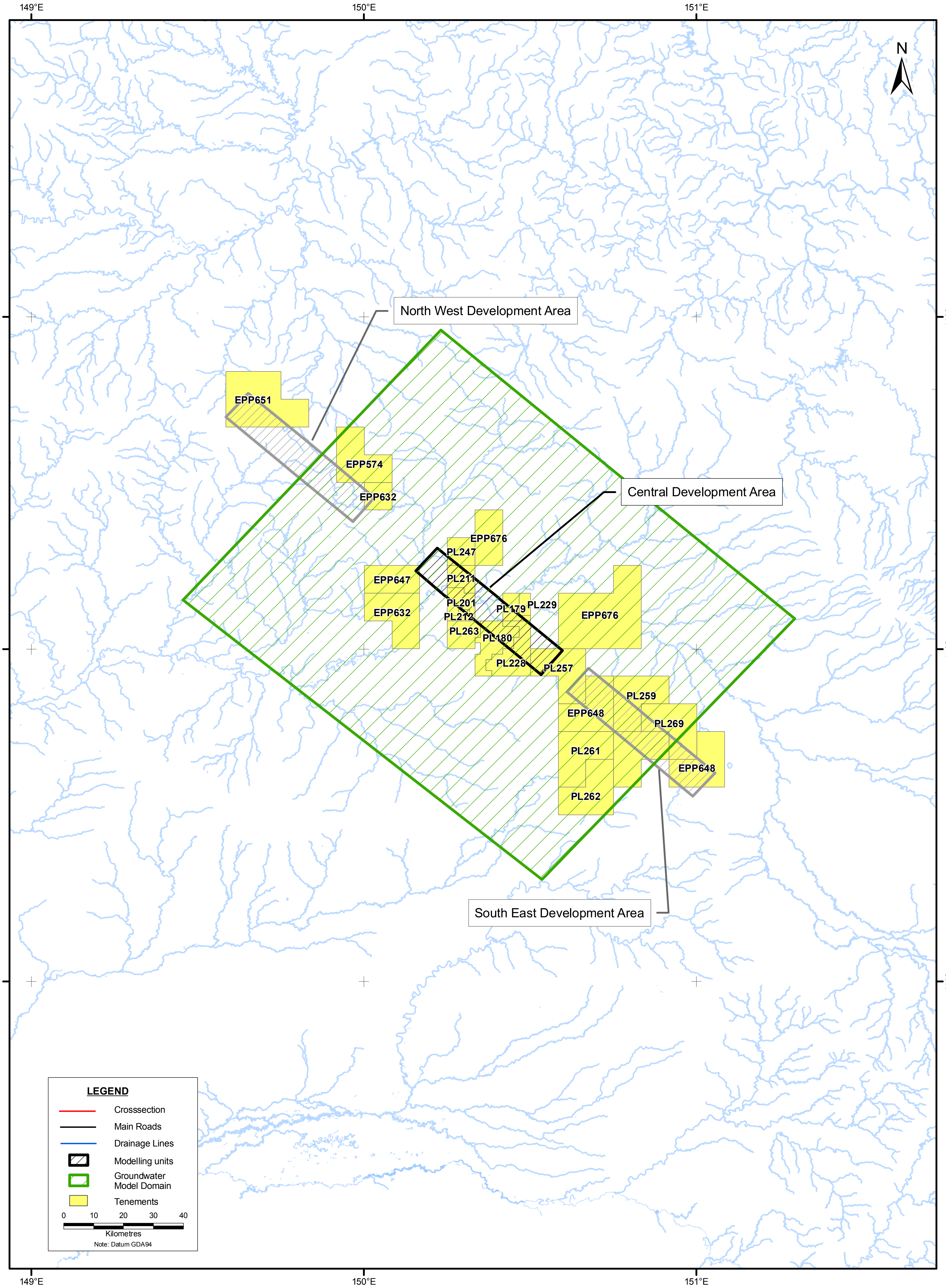
FIGURES

FIGURES

Checked by: ………………………………….

Date: 30 June 2009 ………………………………….



Note:
1. Base map data copyright Mapinfo Australia Pty Ltd.
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CLIENT Queensland Gas Company		PROJECT QGC - LNG EIS Groundwater Study			
DRAWN DK/BQ	DATE 22-04-09	TITLE MODEL DOMAIN - CENTRAL DEVELOPMENT AREA (CDA)			
CHECKED RKH*	DATE 22-04-09				
SCALE 1:1,200,000		PROJECT No 087633050_017	FIGURE No D-1	REV No 1	A3

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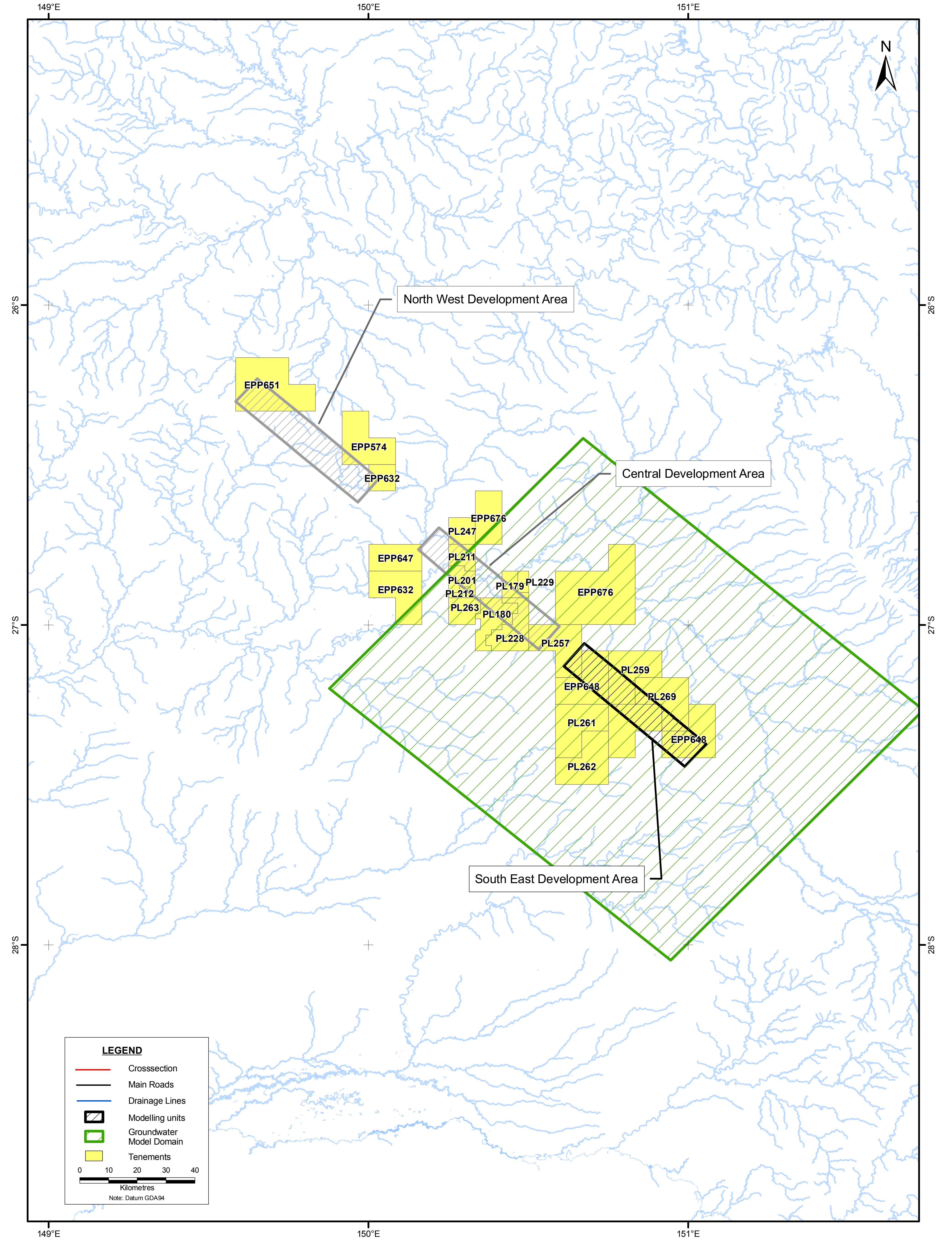
Note: The * beside the typed initials denotes the original drawing issue was signed or initialled by that respective person.



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CLIENT: Queensland Gas Company		PROJECT: QGC - LNG EIS Groundwater Study		
DRAWN: DK/BQ	DATE: 22-04-09	TITLE: **MODEL DOMAIN - SOUTH EAST DEVELOPMENT AREA (SEDA)**		
CHECKED: RKH*	DATE: 22-04-09			
SCALE: 1:1,200,000		PROJECT No: 087633050_017	FIGURE No: **D-2**	REV No: 1 A3

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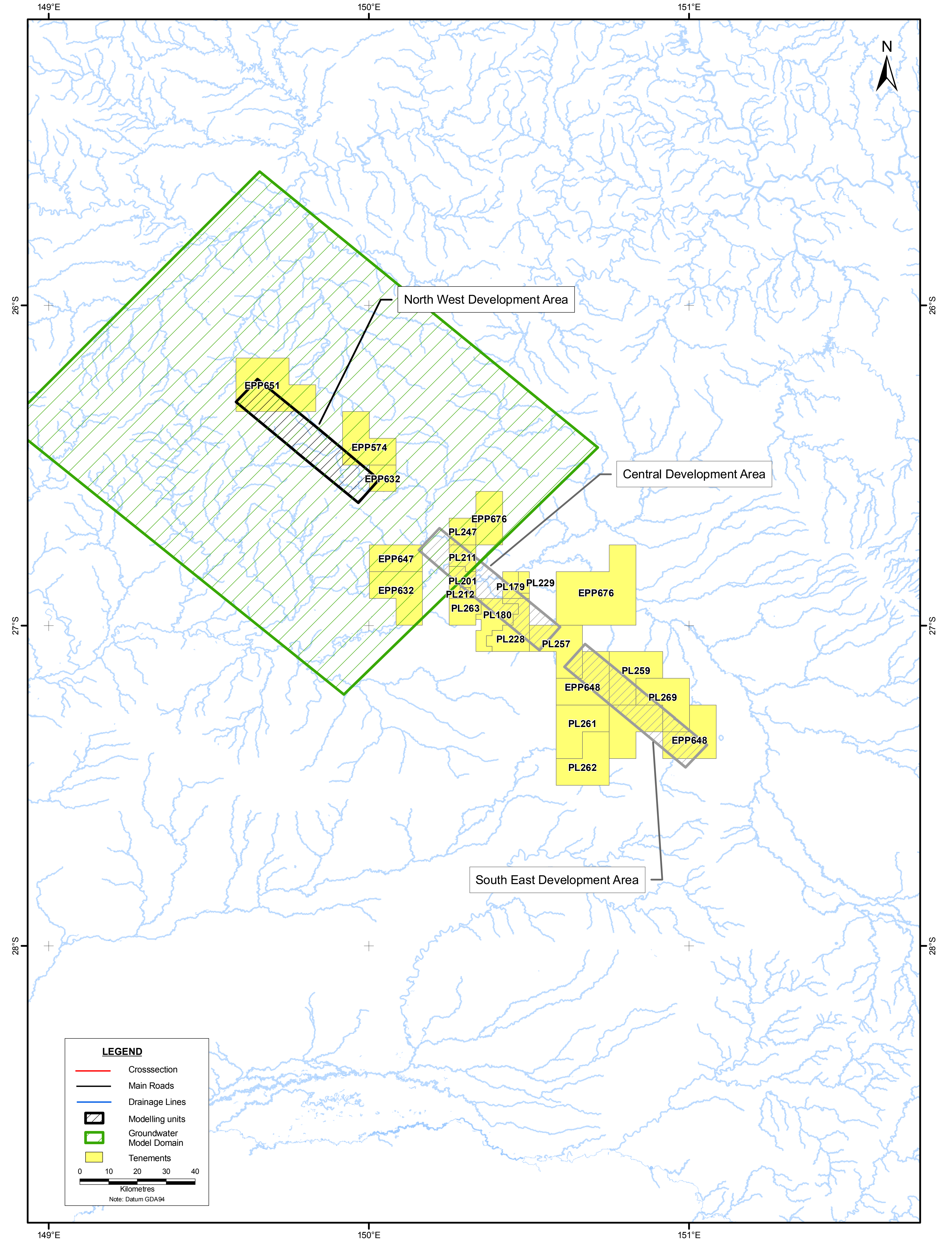
Note: The * beside the typed initials denotes the original drawing issue was signed or initialled by that respective person.



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CLIENT Queensland Gas Company		PROJECT QGC - LNG EIS Groundwater Study	
DRAWN DK/BQ	DATE 22-04-09	TITLE MODEL DOMAIN - NORTH WEST DEVELOPMENT AREA (NWDA)	
CHECKED RKH*	DATE 22-04-09		
SCALE 1:1,200,000		PROJECT No 087633050_017	FIGURE No D-3 / REV No 1 / A3

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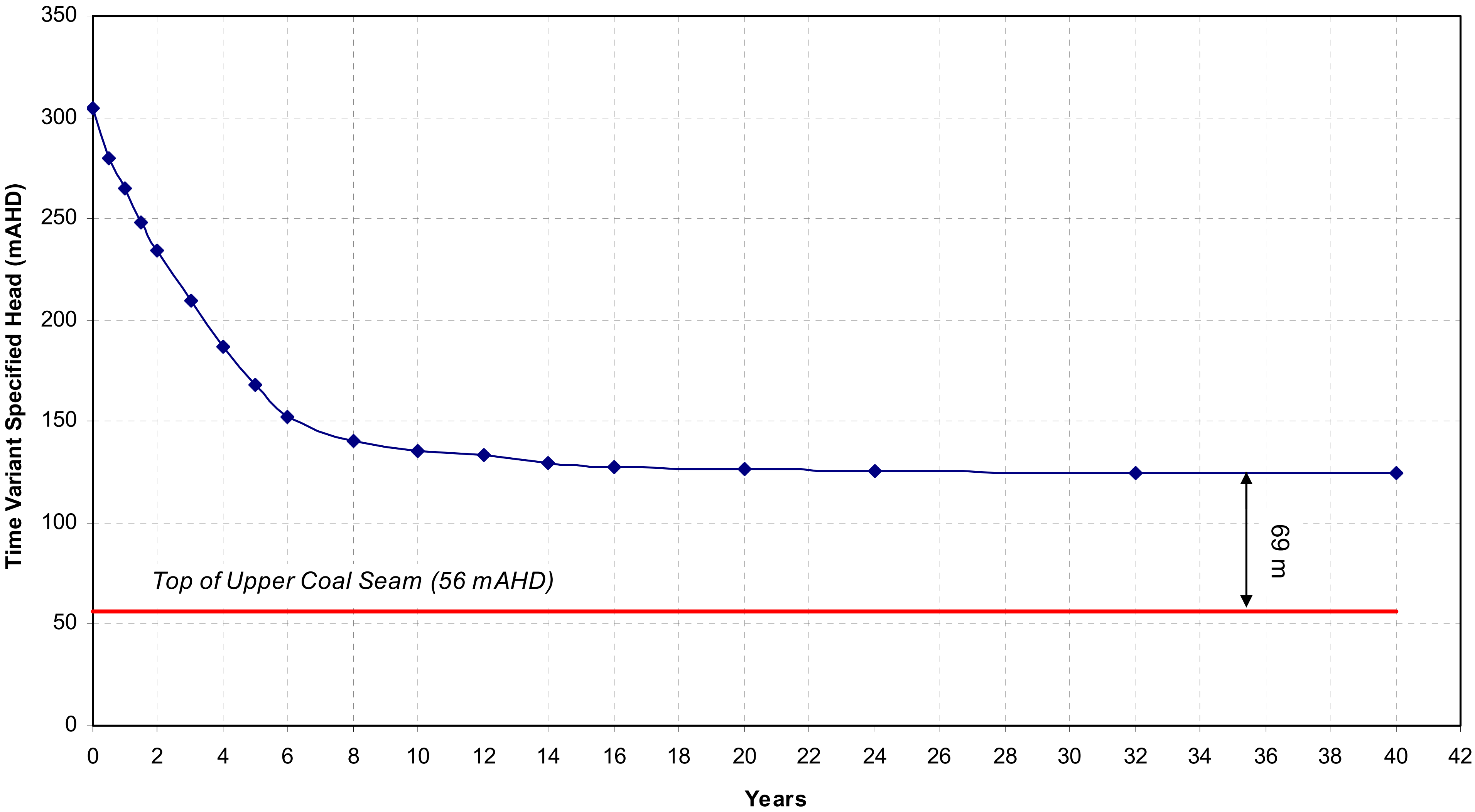

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CLIENT Queensland Gas Company		PROJECT Queensland Gas Company – LNG EIS WATER STUDIES	
DRAWN AB	DATE April 2009	TITLE **Modelled Depressurisation Schedule CDA**	
CHECKED SK	DATE April 2009		
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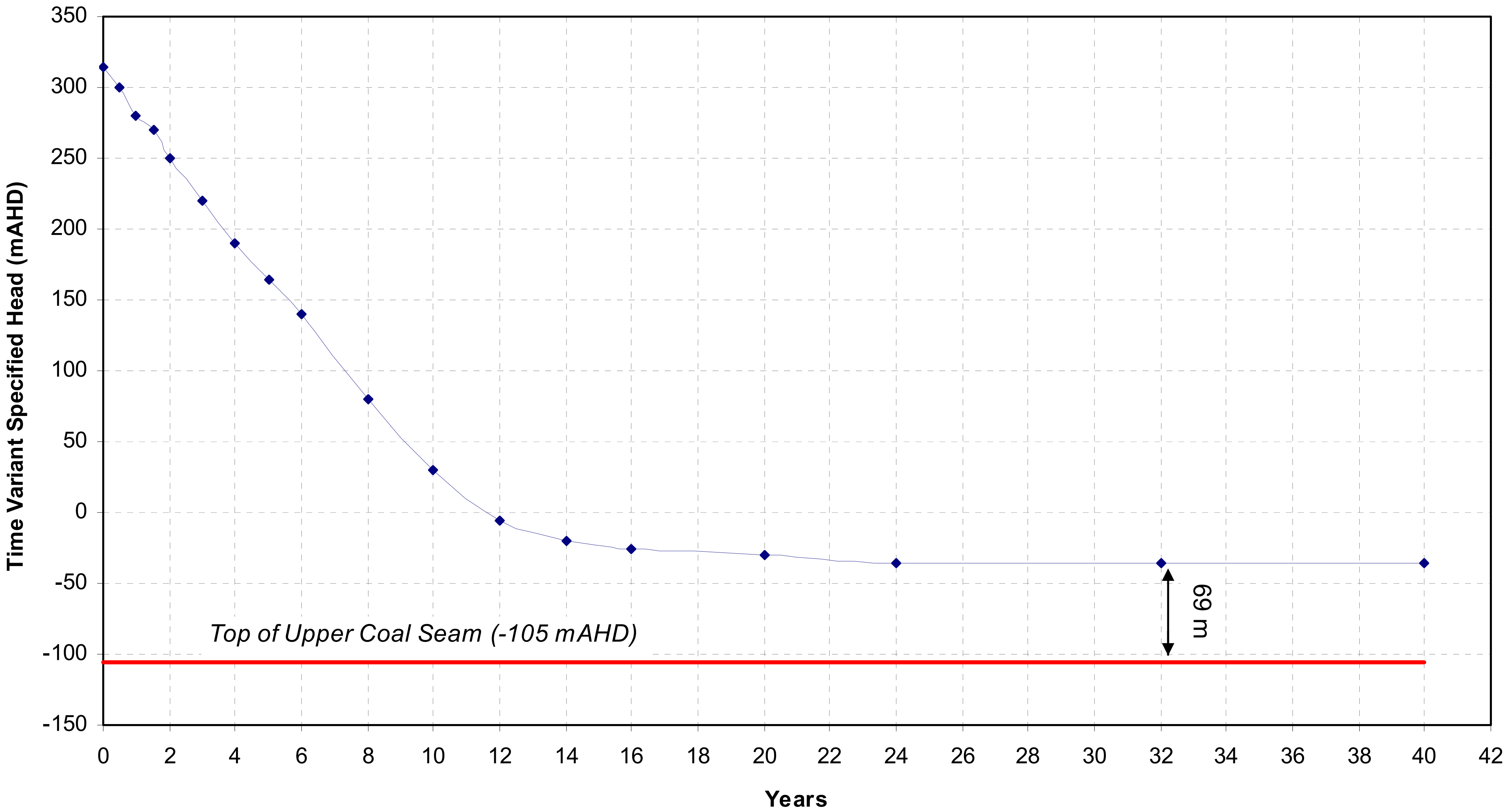

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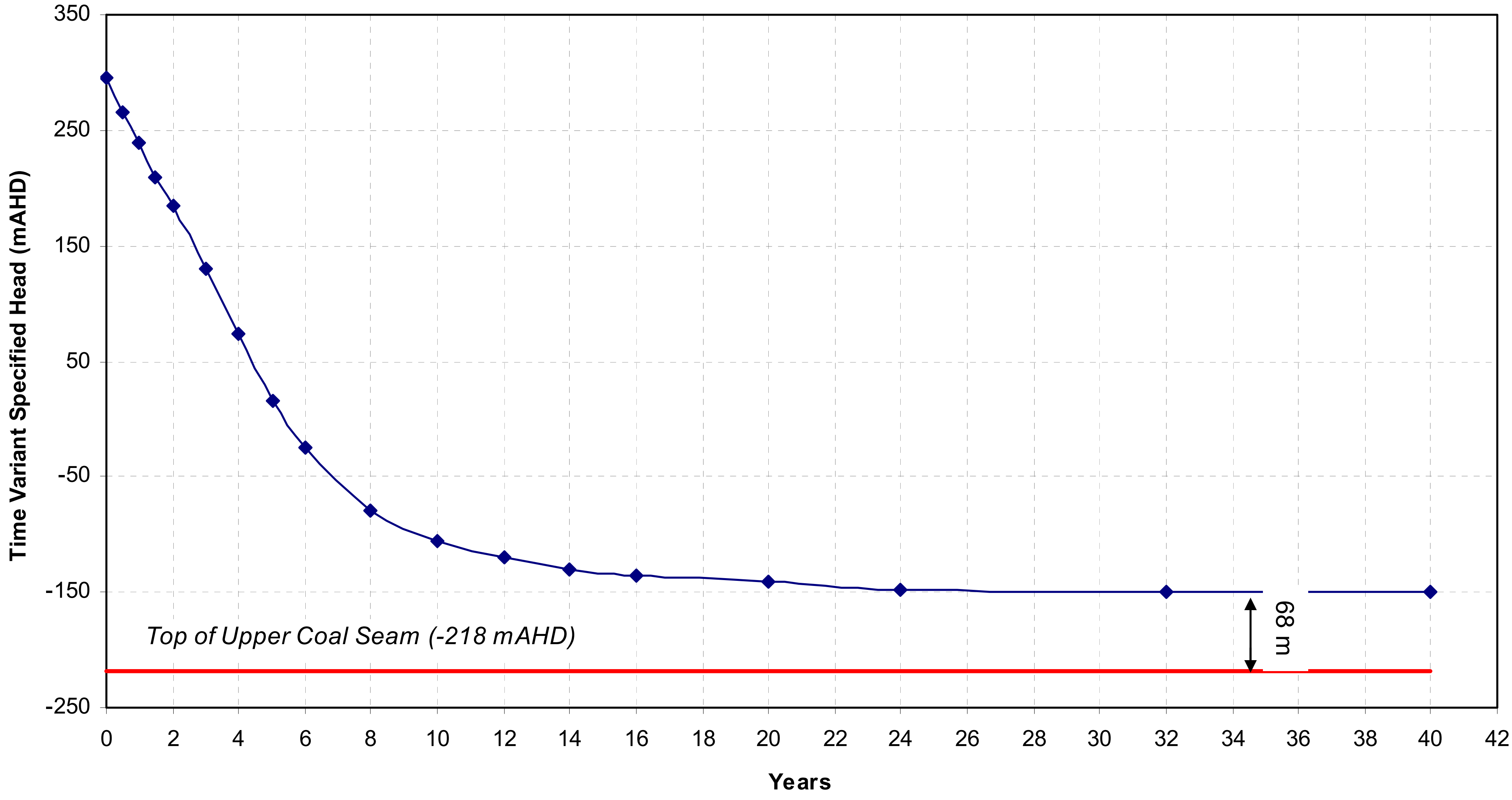

CLIENT Queensland Gas Company		PROJECT Queensland Gas Company – LNG EIS WATER STUDIES		
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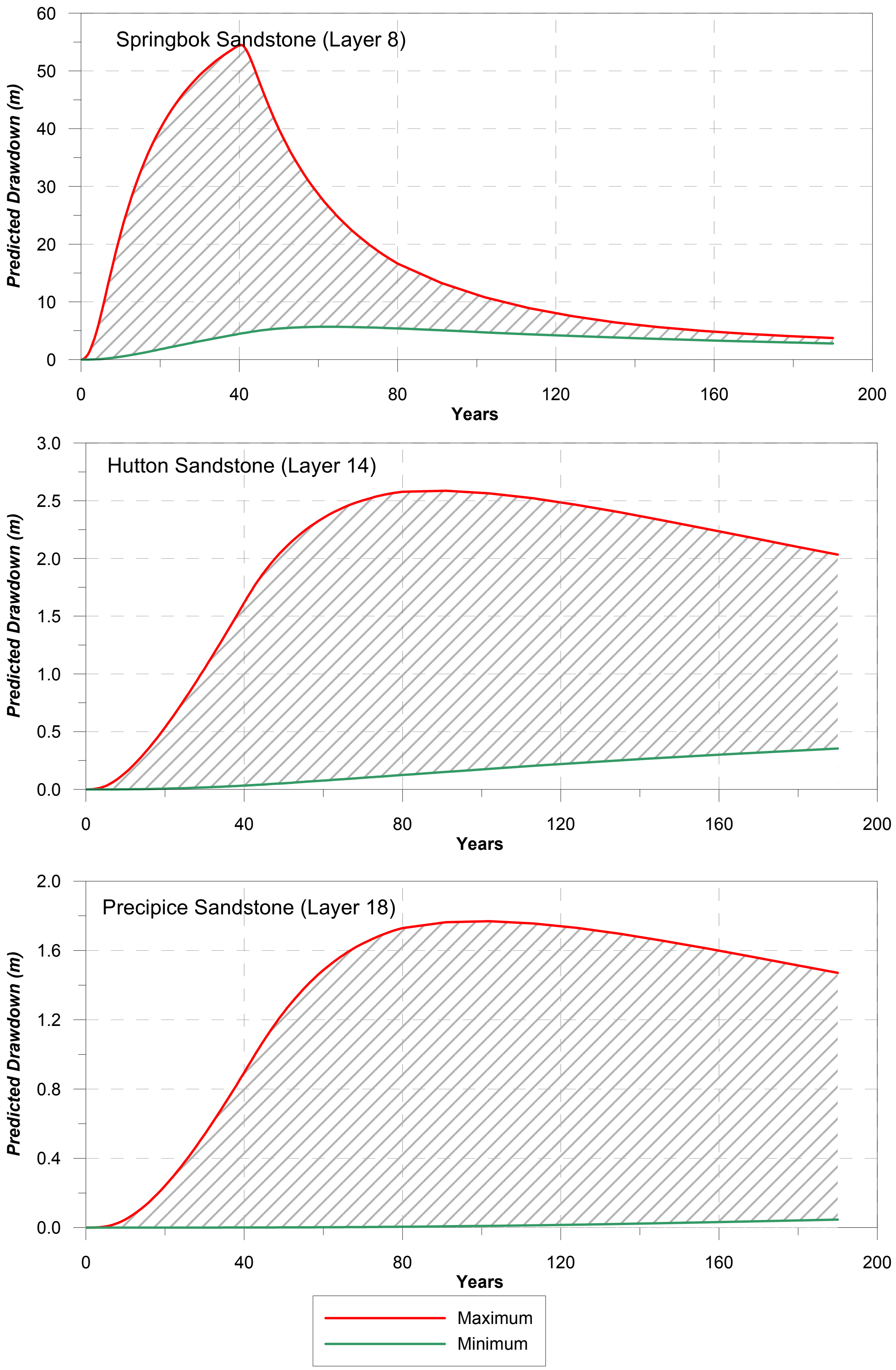
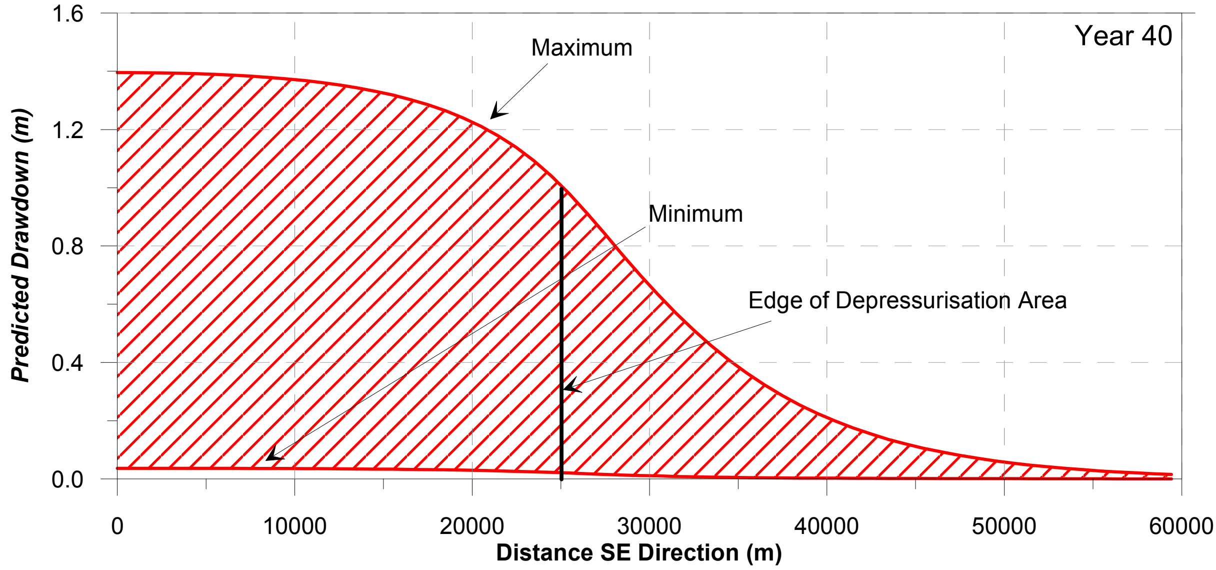
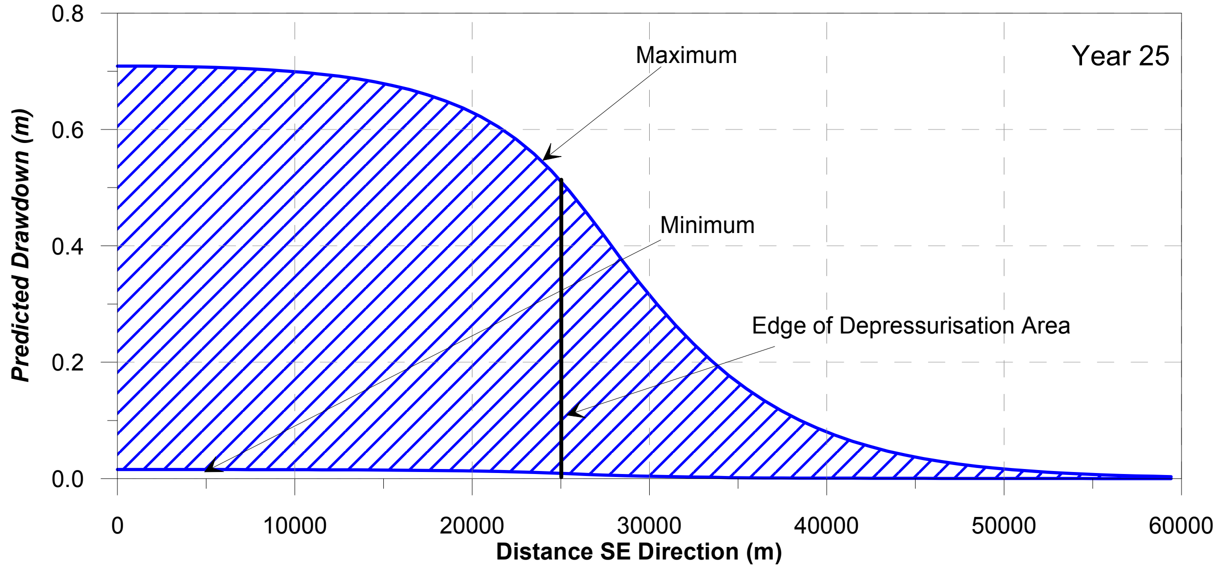
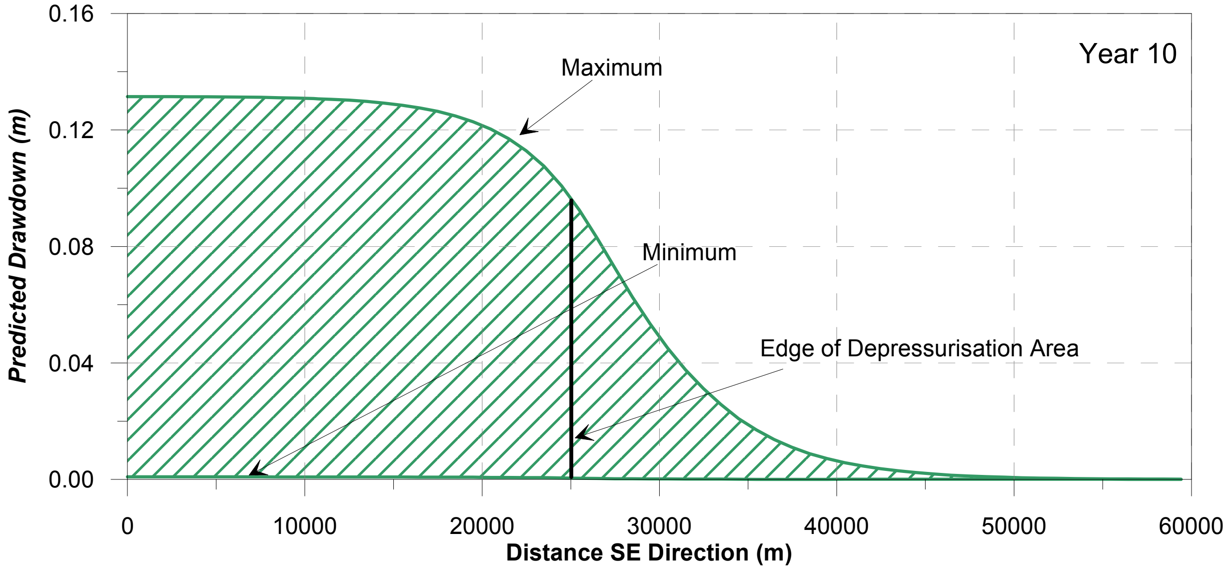


Golder Associates	CLIENT Queensland Gas Company		PROJECT Queensland Gas Company – LNG EIS WATER STUDIES	
	DRAWN AB	DATE April 2009	TITLE Modelled Time Vs Drawdown at 1.8km from Edge of CDA (Springbok, Hutton & Precipice Sandstone)	
	CHECKED SK	DATE April 2009		
	SCALE N/A		PROJECT No 087633050	FIGURE No D-7 · REV No U · A4

Note: 'Maximum' refers to results of model simulation considering maximum potential parameter dataset and 'Minimum' refers to results of model simulation considering minimum potential parameter dataset, as described in the main body of this report.







Golder Associates

CLIENT: Queensland Gas Company

PROJECT: Queensland Gas Company – LNG EIS WATER STUDIES

DRAWN: AB | DATE: April 2009

CHECKED: SK | DATE: April 2009

TITLE: **Modelled Drawdown Vs Distance from Centre of CDA (Gubberamunda Sandstone)**

SCALE: N/A

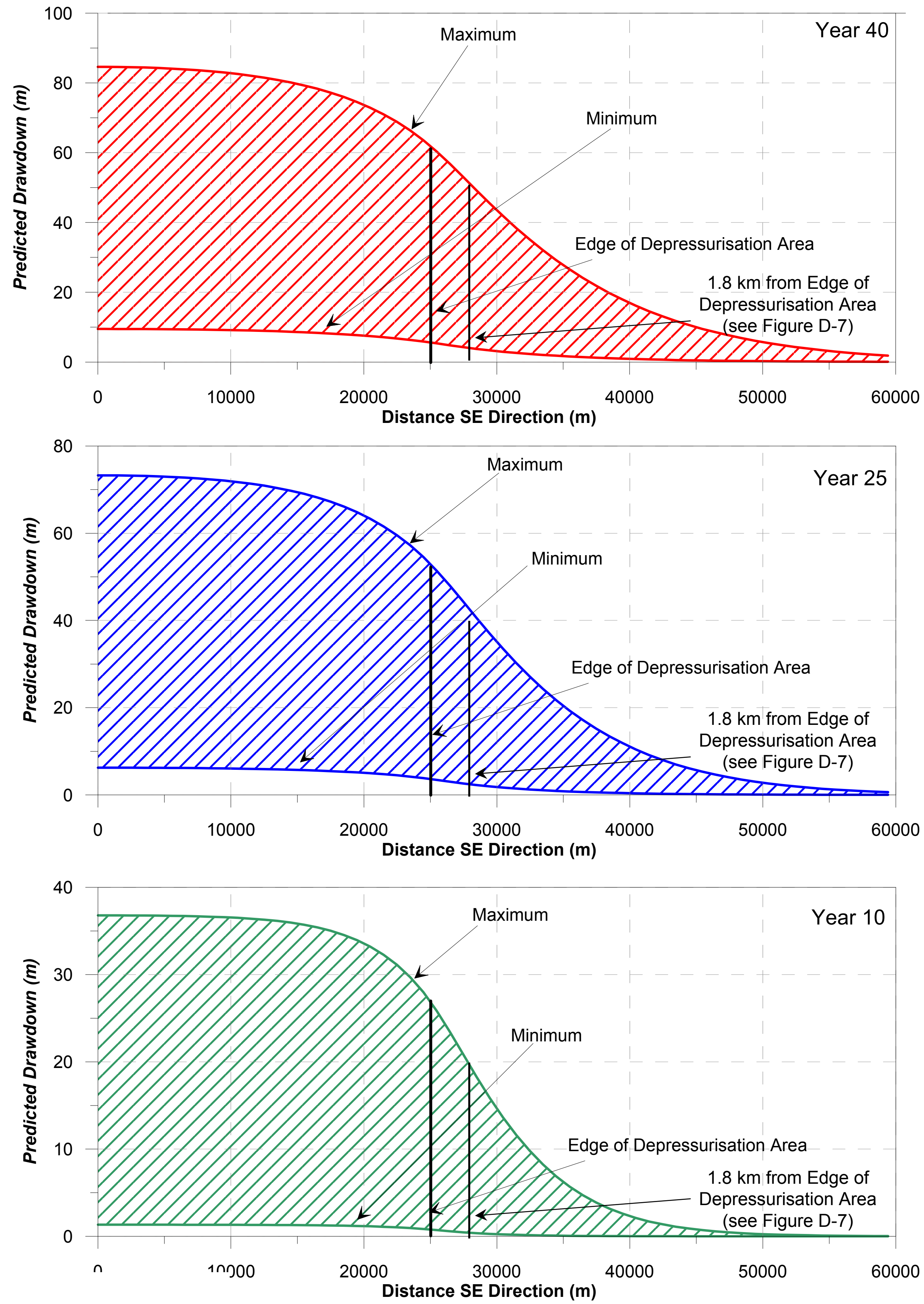
PROJECT No: 087633050

FIGURE No: **D-8**

REV No: U

A4

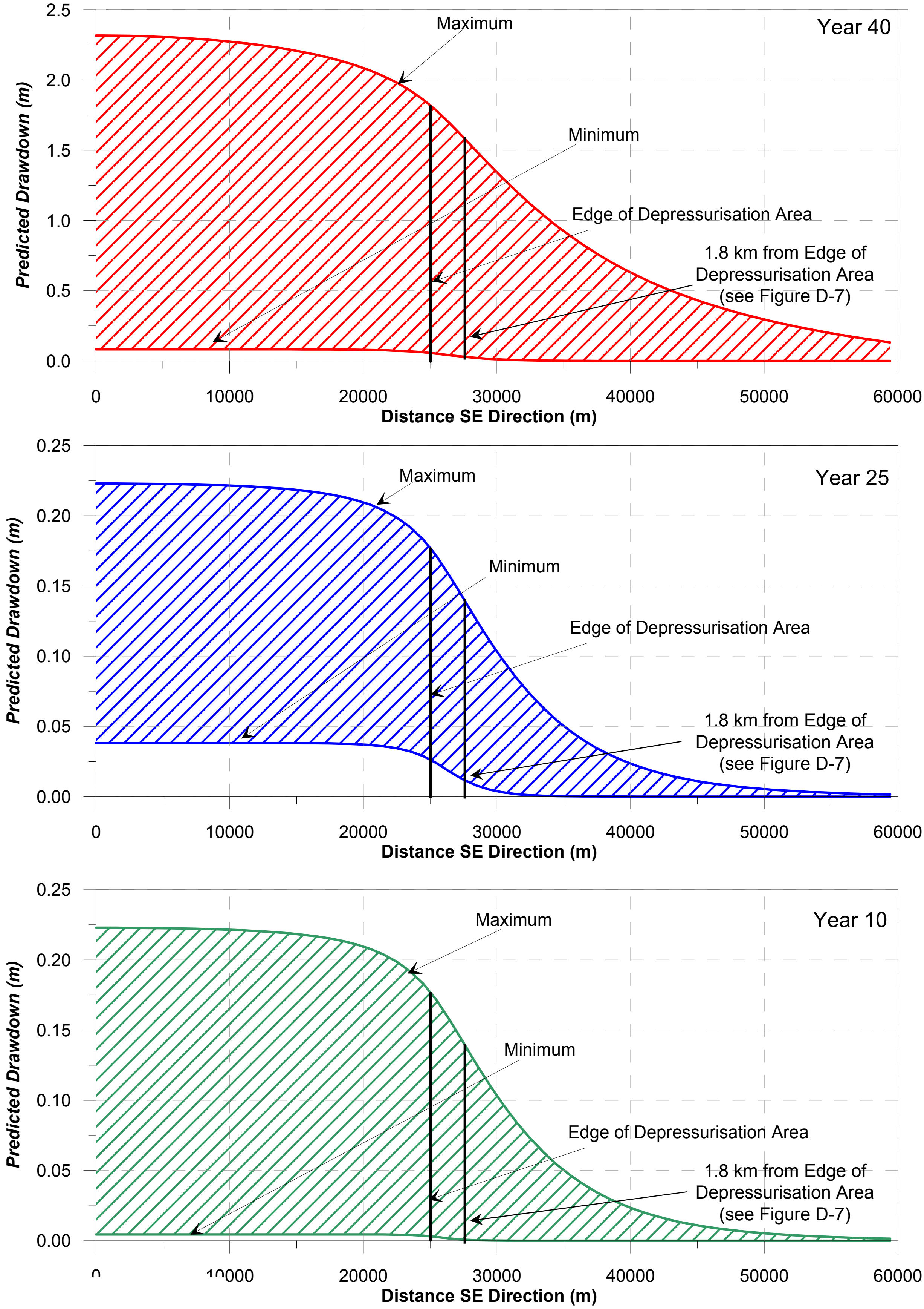
Note: 'Maximum' refers to results of model simulation considering maximum potential parameter dataset and 'Minimum' refers to results of model simulation considering minimum potential parameter dataset, as described in the main body of this report.



Golder Associates

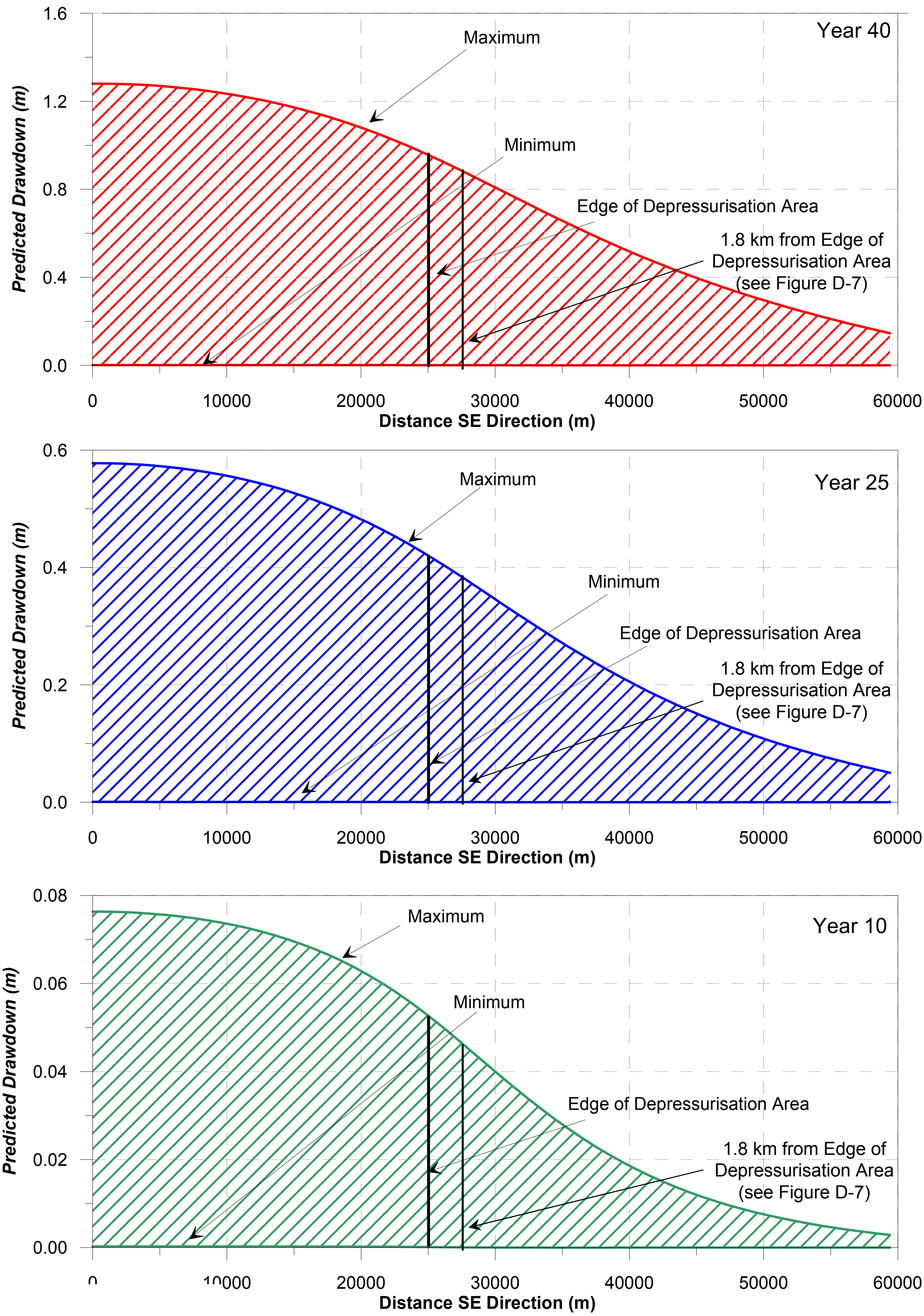
CLIENT: Queensland Gas Company		PROJECT: Queensland Gas Company – LNG EIS WATER STUDIES	
DRAWN: AB	DATE: April 2009	TITLE: **Modelled Drawdown Vs Distance from Centre of CDA (Springbok Sandstone)**	
CHECKED: SK	DATE: April 2009		
SCALE: N/A		PROJECT No: 087633050	FIGURE No: **D-9** REV No: **U** **A4**

Note: 'Maximum' refers to results of model simulation considering maximum potential parameter dataset and 'Minimum' refers to results of model simulation considering minimum potential parameter dataset, as described in the main body of this report.



CLIENT Queensland Gas Company		PROJECT Queensland Gas Company – LNG EIS WATER STUDIES	
DRAWN AB	DATE April 2009	TITLE **Modelled Drawdown Vs Distance from Centre of CDA (Hutton Sandstone)**	
CHECKED SK	DATE April 2009		
SCALE N/A		PROJECT No 087633050	FIGURE No **D-10** REV No **U** **A4**

Note: 'Maximum' refers to results of model simulation considering maximum potential parameter dataset and 'Minimum' refers to results of model simulation considering minimum potential parameter dataset, as described in the main body of this report.



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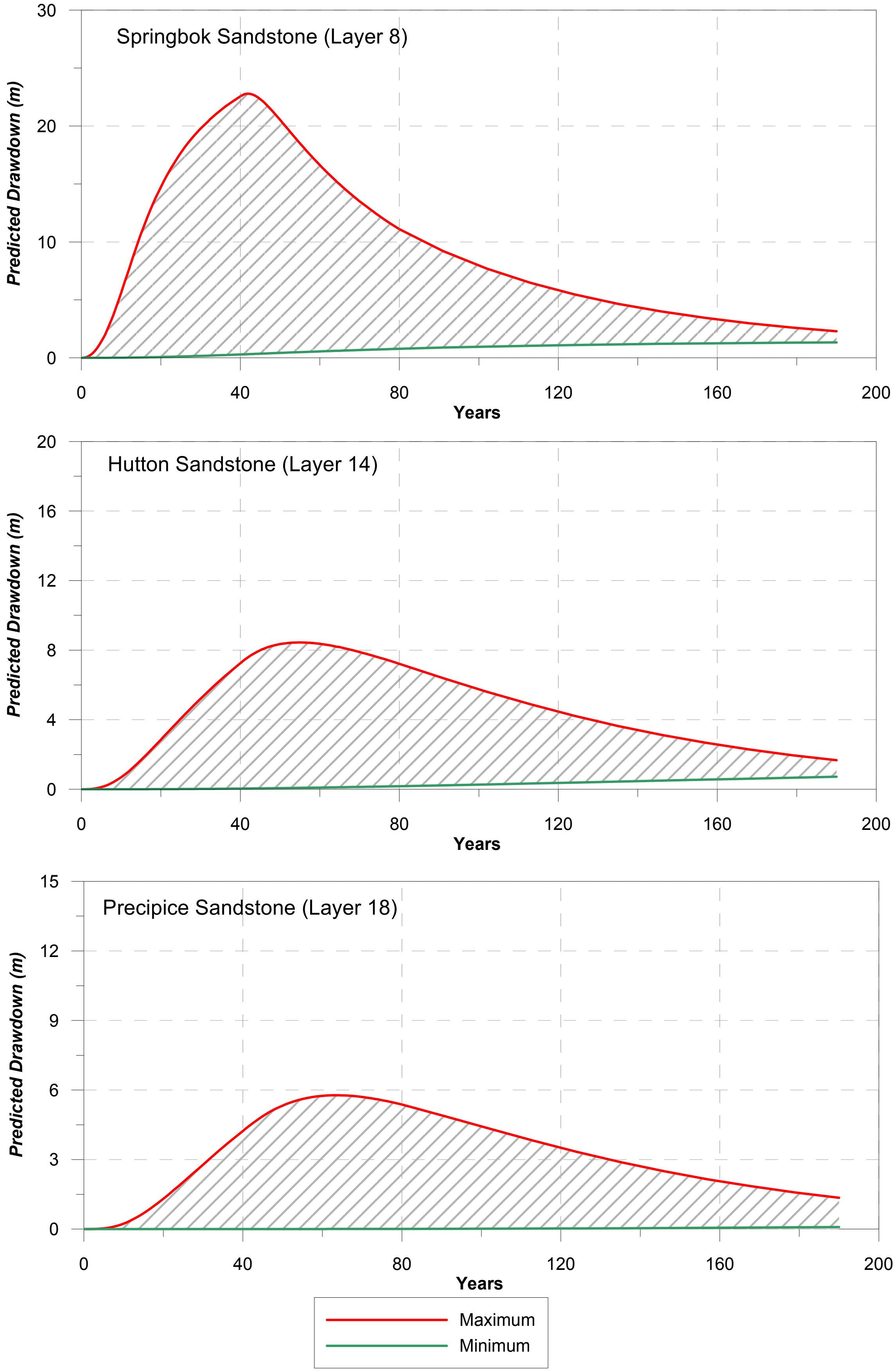
DRAWN AB	DATE April 2009	TITLE Modelled Drawdown Vs Distance from Centre of CDA (Precipice Sandstone)	
CHECKED SK	DATE April 2009		
SCALE N/A		PROJECT No 087633050	FIGURE No D-11 REV No U A4

Golder Associates

Note: 'Maximum' refers to results of model simulation considering maximum potential parameter dataset and 'Minimum' refers to results of model simulation considering minimum potential parameter dataset, as described in the main body of this report.



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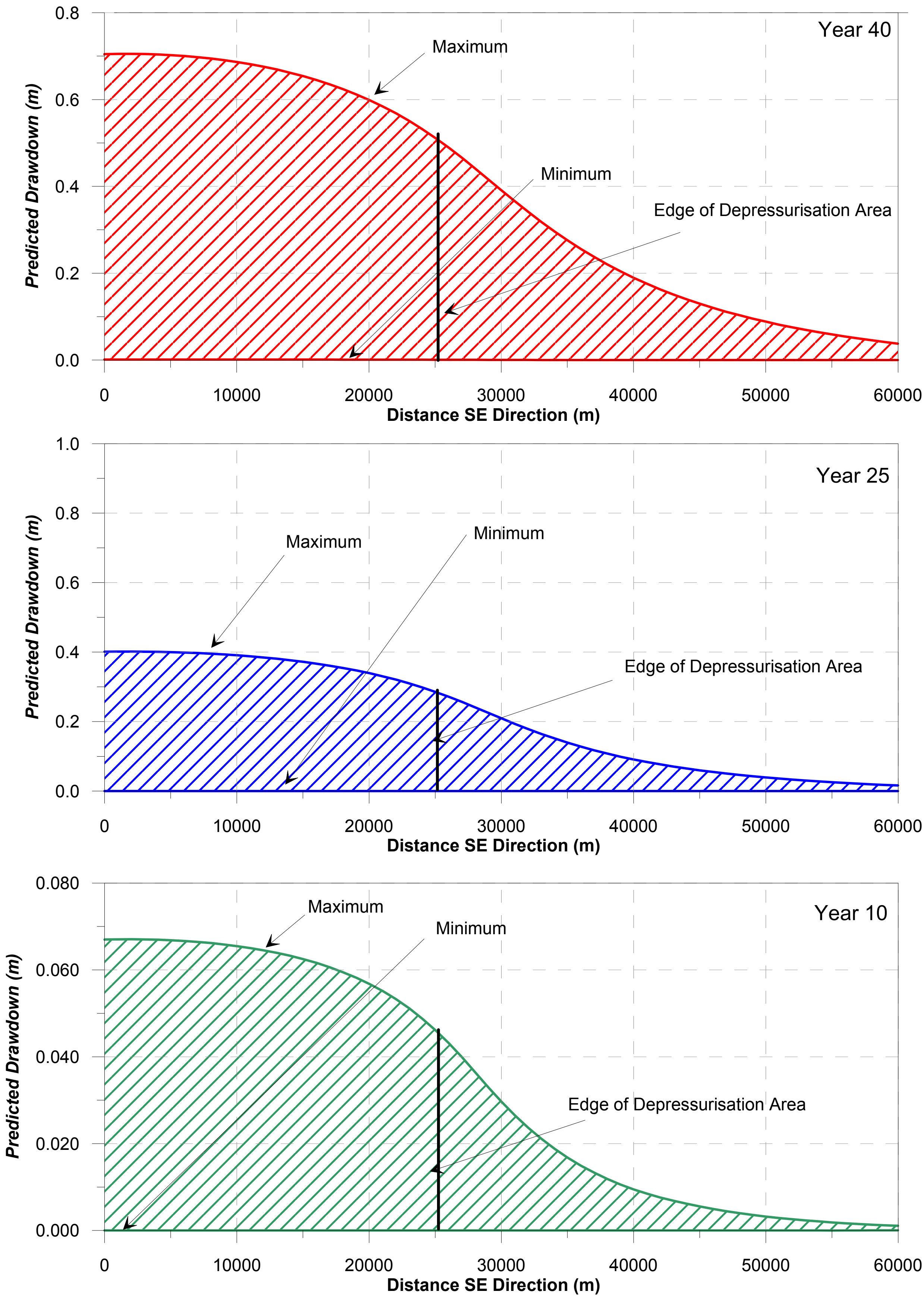
	DRAWN AB	DATE April 2009	TITLE Modelled Time Vs Drawdown at 1.8km from Edge of SEDA (Springbok, Hutton & Precipice Sandstone)				
	CHECKED SK	DATE April 2009					
	SCALE N/A		PROJECT No 087633050	FIGURE No D-12	REV No U	A4	

Note: 'Maximum' refers to results of model simulation considering maximum potential parameter dataset and 'Minimum' refers to results of model simulation considering minimum potential parameter dataset, as described in the main body of this report.



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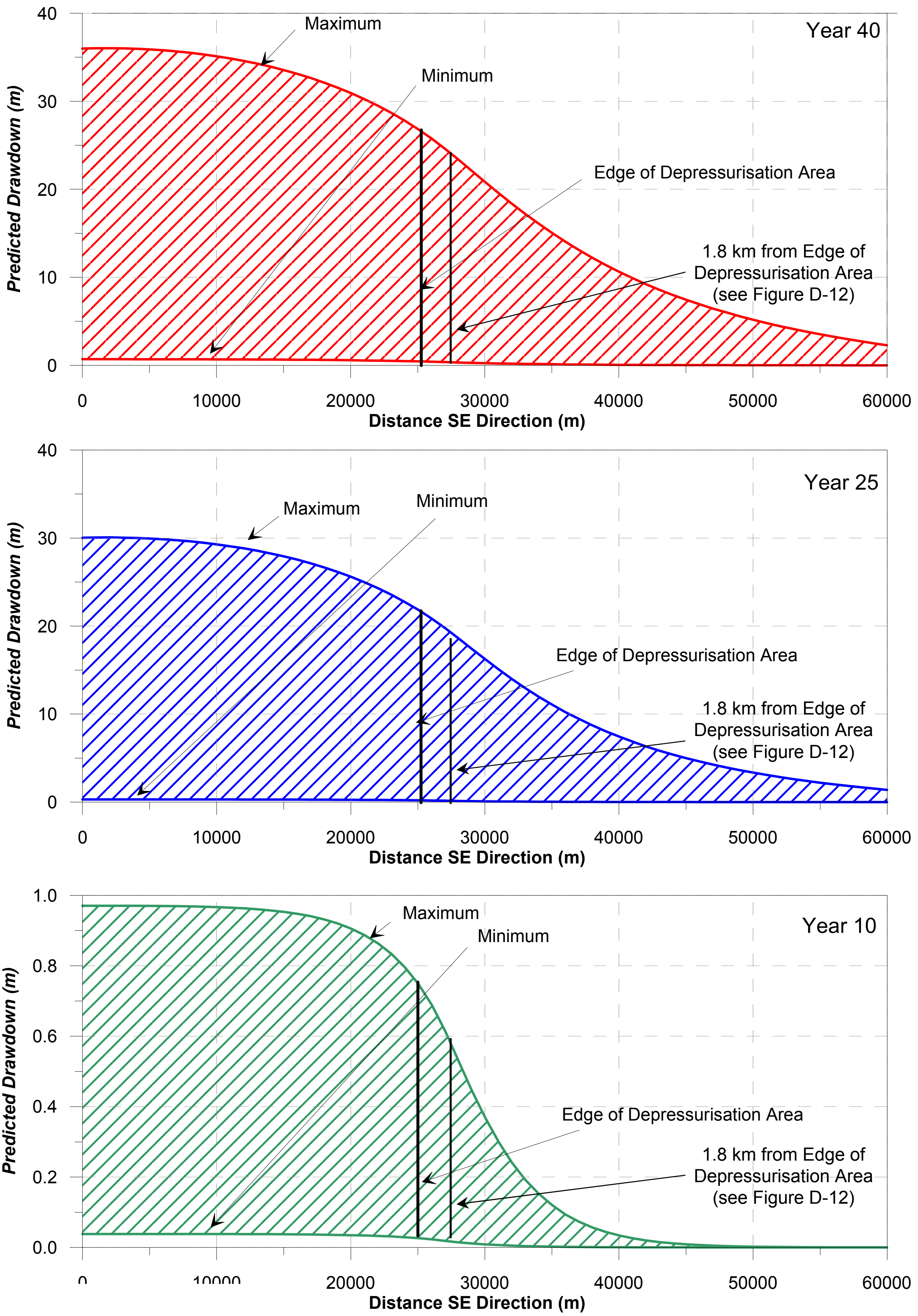
	DRAWN AB	DATE April 2009	TITLE Modelled Drawdown Vs Distance from Centre of SEDA (Gubberamunda Sandstone)
	CHECKED SK	DATE April 2009	
	SCALE N/A		PROJECT No 087633050 · FIGURE No D-13 · REV No U · A4

Note: 'Maximum' refers to results of model simulation considering maximum potential parameter dataset and 'Minimum' refers to results of model simulation considering minimum potential parameter dataset, as described in the main body of this report.



Golder Associates

CLIENT Queensland Gas Company

PROJECT Queensland Gas Company – LNG EIS WATER STUDIES

DRAWN AB | DATE April 2009

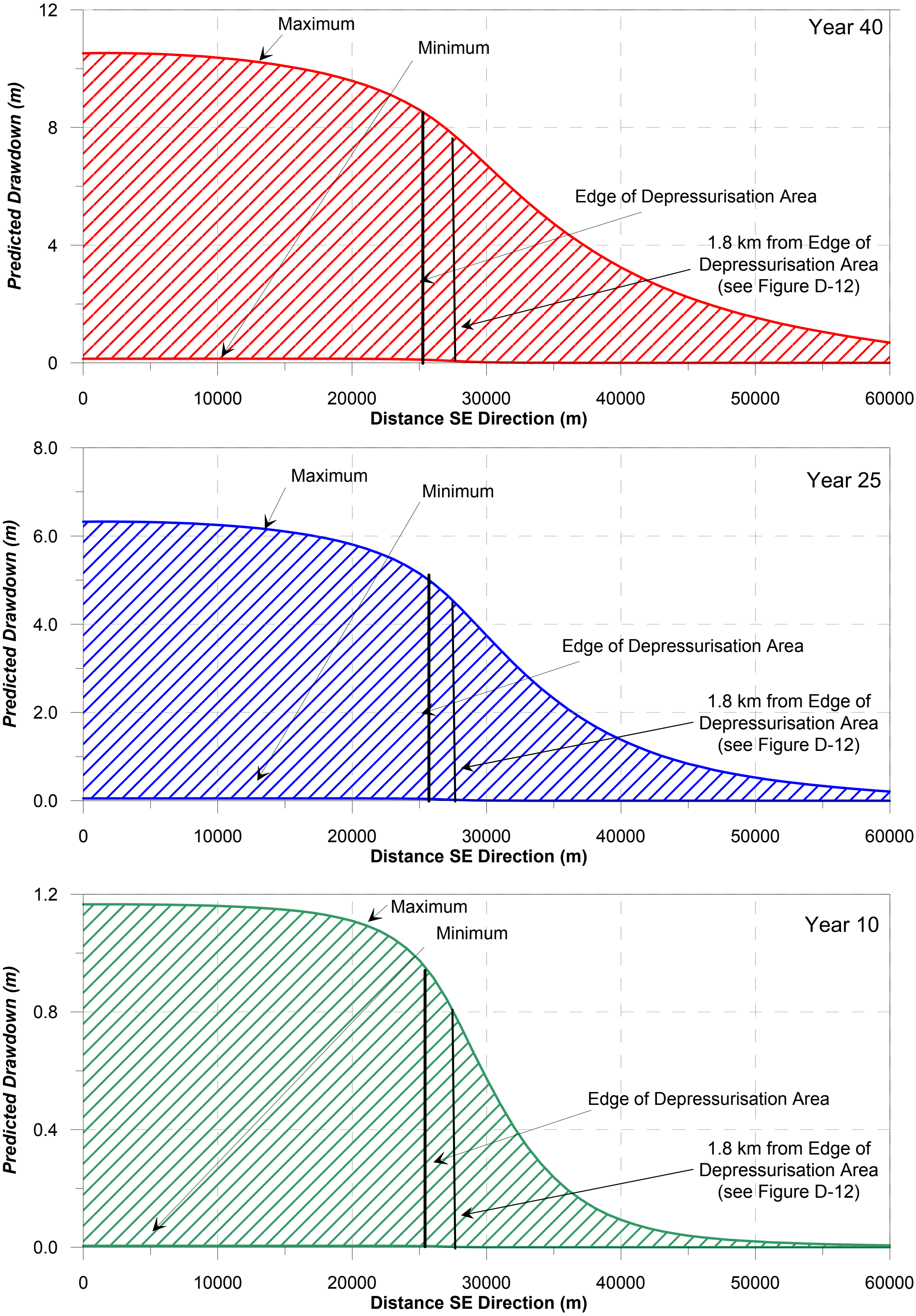
CHECKED SK | DATE April 2009

SCALE N/A

TITLE **Modelled Drawdown Vs Distance from Centre of SEDA (Springbok Sandstone)**

PROJECT No 087633050 | FIGURE No **D-14** | REV No **U** | **A4**

Note: 'Maximum' refers to results of model simulation considering maximum potential parameter dataset and 'Minimum' refers to results of model simulation considering minimum potential parameter dataset, as described in the main body of this report.



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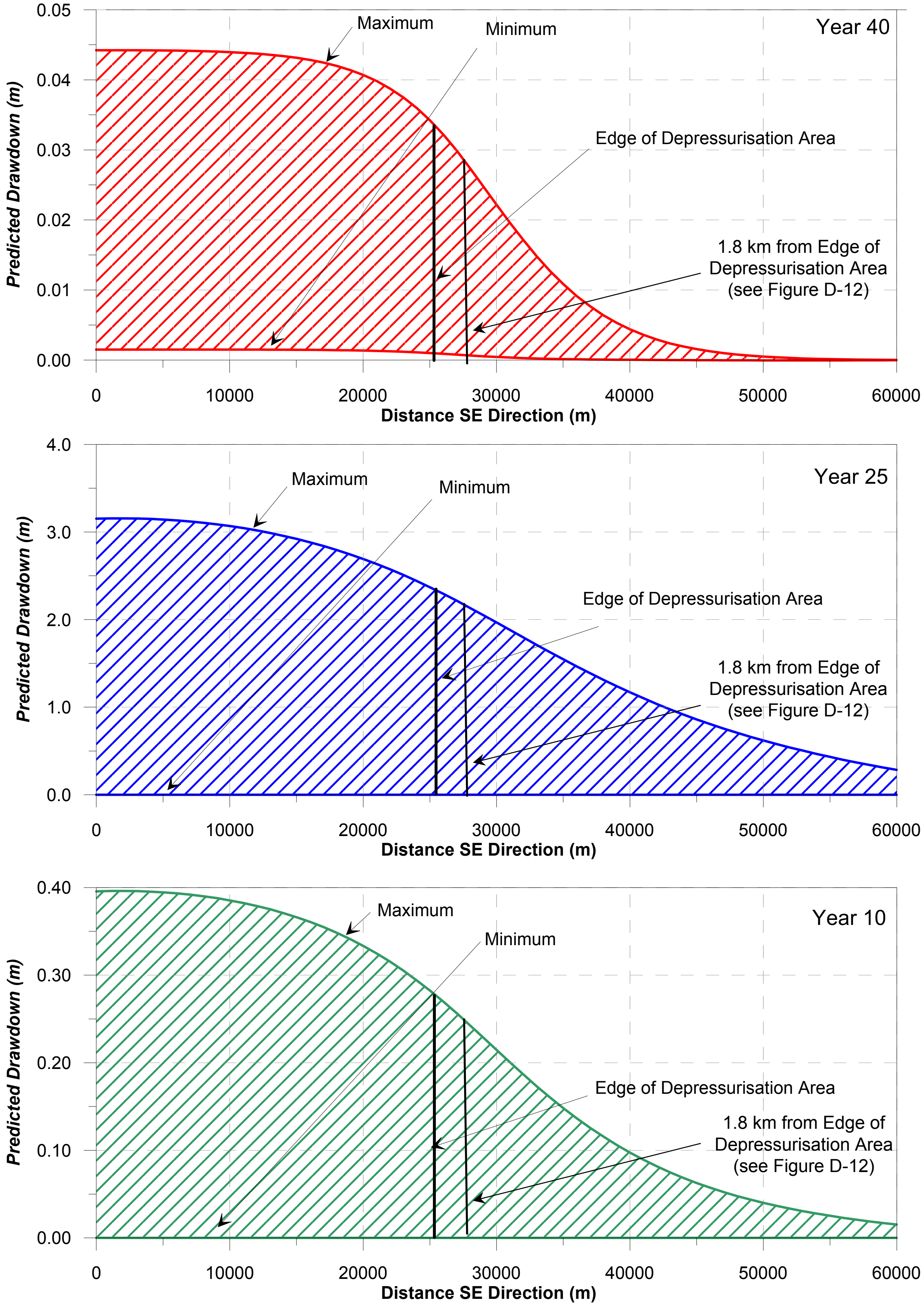
	DRAWN AB	DATE April 2009	TITLE Modelled Drawdown Vs Distance from Centre of SEDA (Hutton Sandstone)
	CHECKED SK	DATE April 2009	
	SCALE N/A		PROJECT No 087633050 / FIGURE No D-15 / REV No U / A4

Note: 'Maximum' refers to results of model simulation considering maximum potential parameter dataset and 'Minimum' refers to results of model simulation considering minimum potential parameter dataset, as described in the main body of this report.



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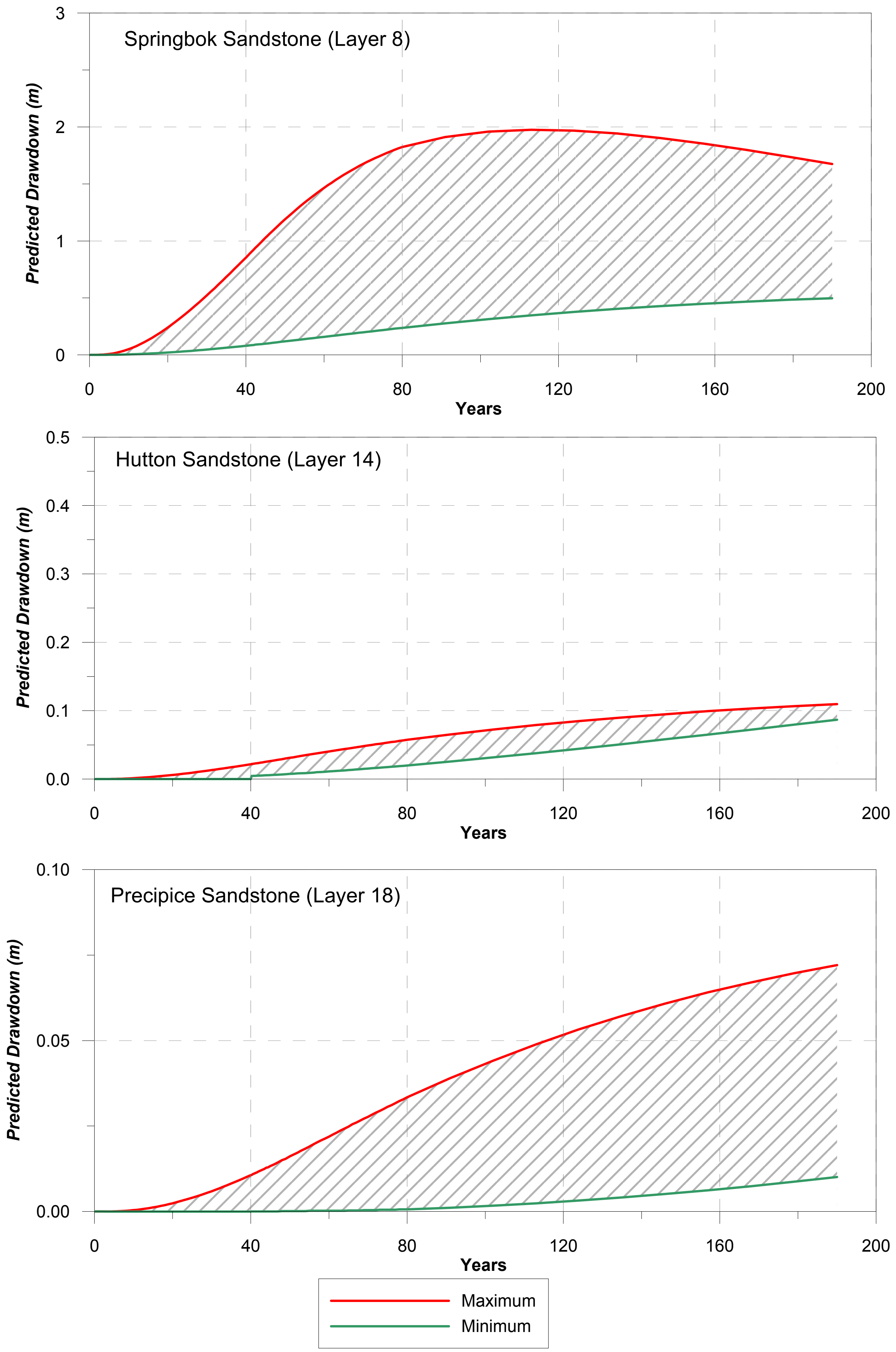
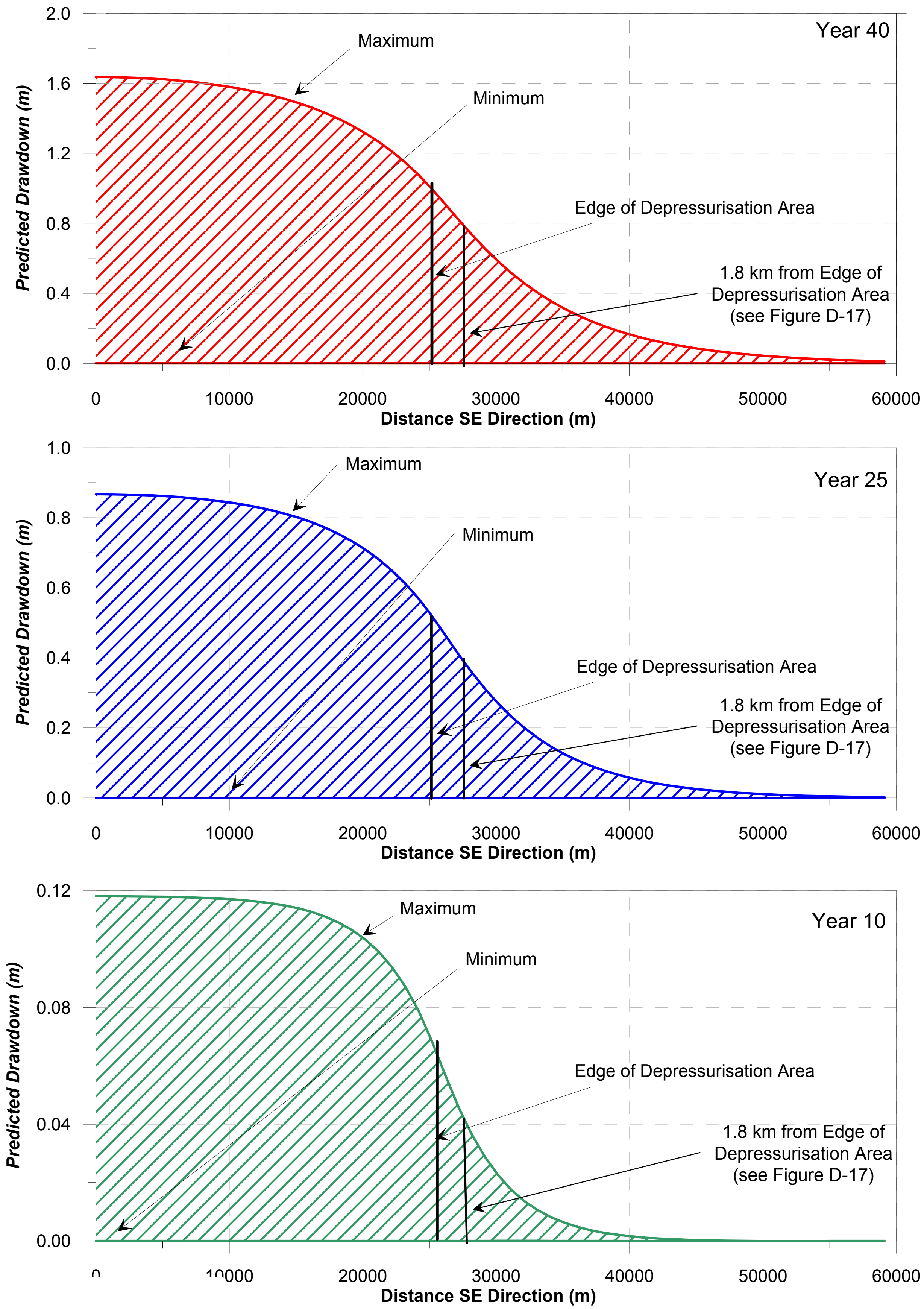
CLIENT Queensland Gas Company		PROJECT Queensland Gas Company – LNG EIS WATER STUDIES			
DRAWN AB	DATE April 2009	TITLE **Modelled Drawdown Vs Distance from Centre of SEDA (Precipice Sandstone)**			
CHECKED SK	DATE April 2009				
SCALE N/A		PROJECT No 087633050	FIGURE No **D-16**	REV No **U**	**A4**

Note: 'Maximum' refers to results of model simulation considering maximum potential parameter dataset and 'Minimum' refers to results of model simulation considering minimum potential parameter dataset, as described in the main body of this report.



Golder Associates	CLIENT Queensland Gas Company		PROJECT Queensland Gas Company – LNG EIS WATER STUDIES
	DRAWN AB	DATE April 2009	TITLE Modelled Time Vs Drawdown at 1.8km from Edge of NWDA (Springbok, Hutton & Precipice Sandstone)
	CHECKED SK	DATE April 2009	
	SCALE N/A		PROJECT No 087633050 — FIGURE No D-17 — REV No U — A4

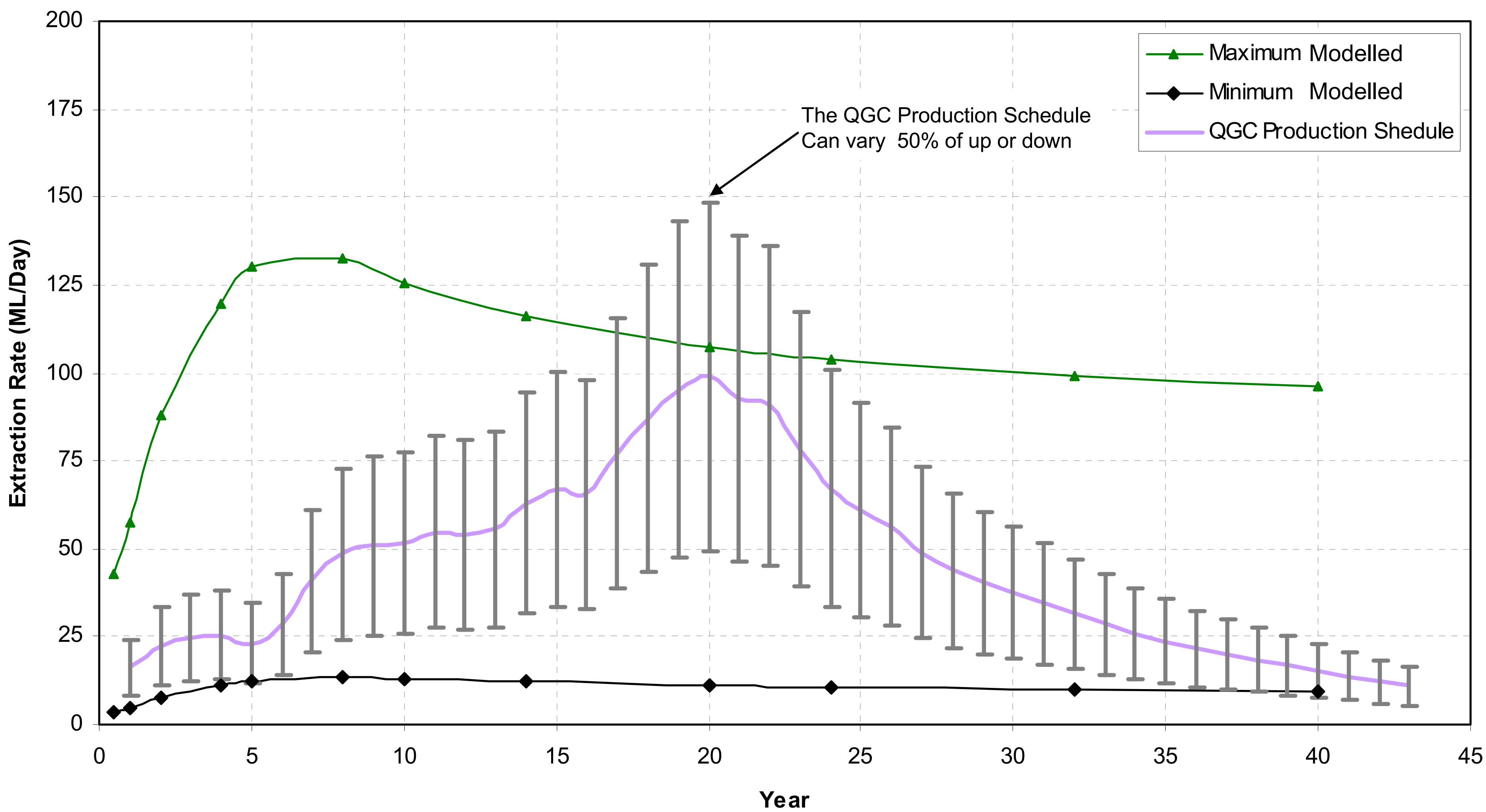
Note: ‘Maximum’ refers to results of model simulation considering maximum potential parameter dataset and ‘Minimum’ refers to results of model simulation considering minimum potential parameter dataset, as described in the main body of this report.



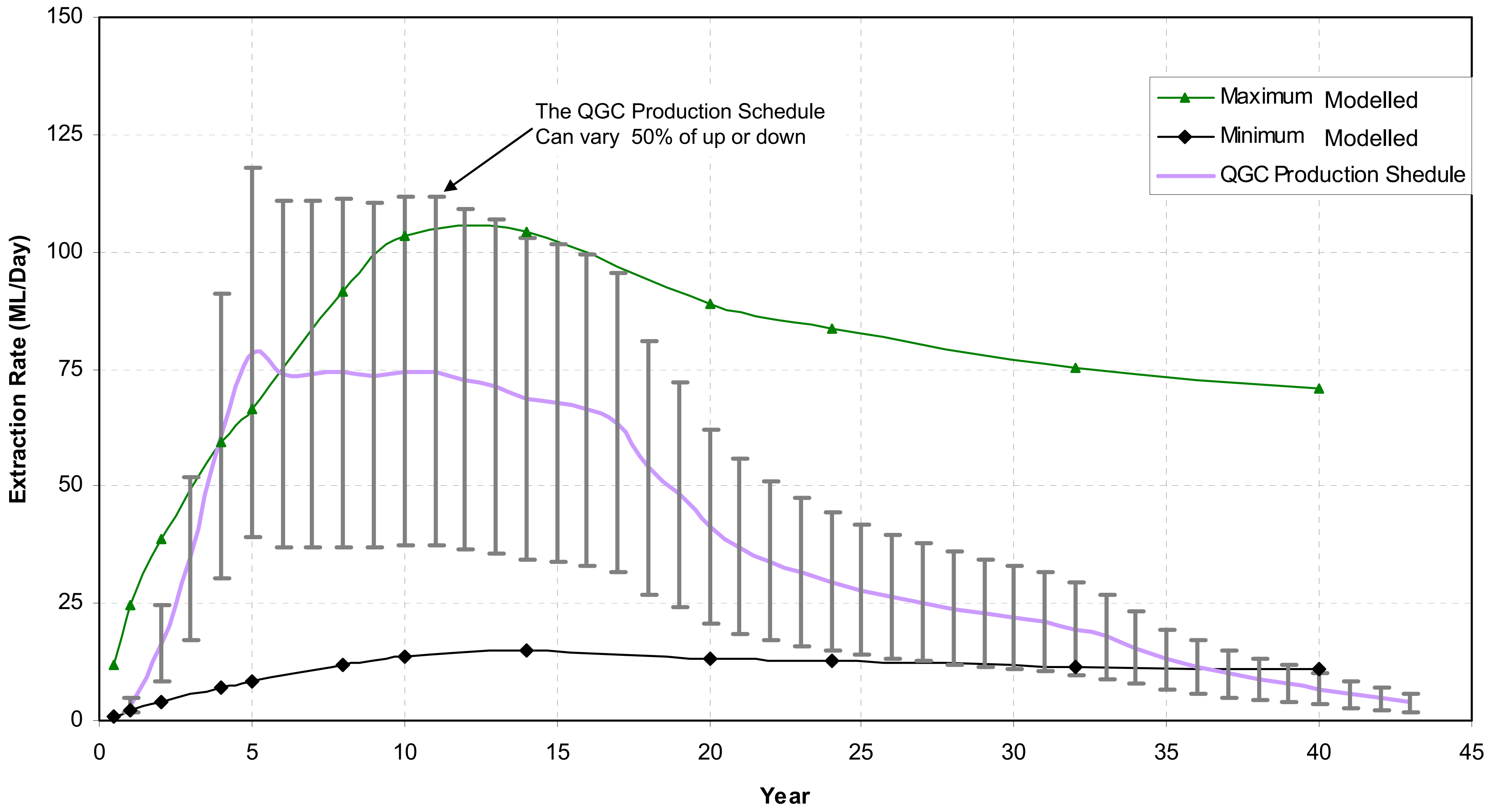
Golder Associates

CLIENT: Queensland Gas Company		PROJECT: Queensland Gas Company – LNG EIS WATER STUDIES	
DRAWN: AB	DATE: April 2009	TITLE: **Modelled Drawdown Vs Distance from Centre of NWDA (Springbok Sandstone)**	
CHECKED: SK	DATE: April 2009		
SCALE: N/A		PROJECT No: 087633050	FIGURE No: **D-18** REV No: U **A4**

Note: 'Maximum' refers to results of model simulation considering maximum potential parameter dataset and 'Minimum' refers to results of model simulation considering minimum potential parameter dataset, as described in the main body of this report.



Golder Associates	CLIENT Queensland Gas Company		PROJECT Queensland Gas Company – LNG EIS WATER STUDIES
	DRAWN AB	DATE April 2009	TITLE **Modelled Total Groundwater Extraction Rate (ML/day) - CDA**
	CHECKED SK	DATE April 2009	
	SCALE Not to scale		PROJECT No 087633050 · FIGURE No **D-19** · REV No **U** · **A4**



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	DRAWN AB	DATE April 2009	TITLE **Modelled Total Groundwater Extraction Rate (ML/day) - SEDA**		
	CHECKED SK	DATE April 2009			
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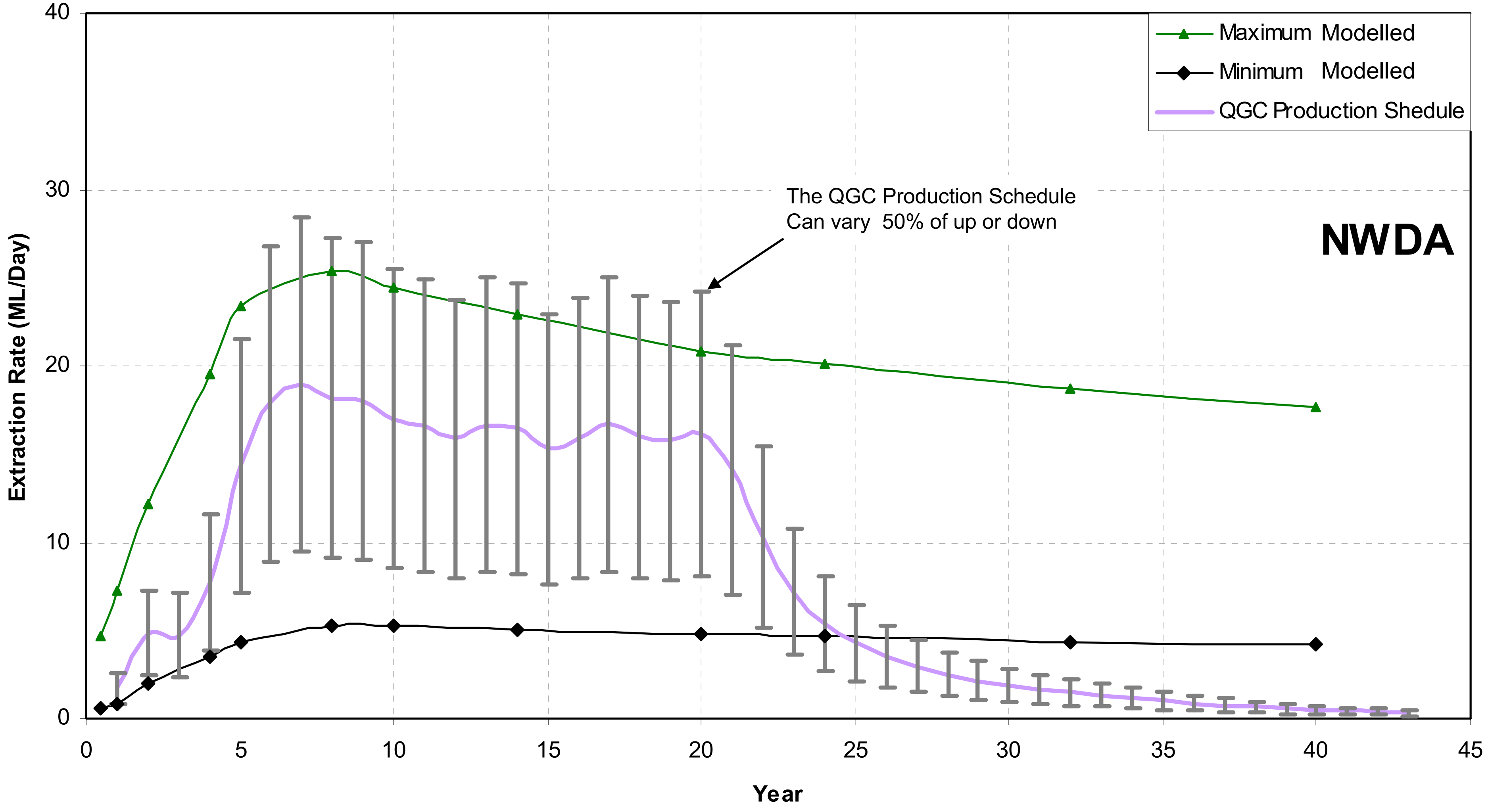

Golder Associates	CLIENT Queensland Gas Company		PROJECT Queensland Gas Company – LNG EIS WATER STUDIES	
	DRAWN AB	DATE April 2009	TITLE **Modelled Total Groundwater Extraction Rate (ML/day) - NWDA**	
	CHECKED SK	DATE April 2009		
	SCALE Not to scale		PROJECT No 087633050	FIGURE No D-21 · REV No U · A4

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Golder Associates

Department of **Employment, Economic Development and Innovation**

Code of Practice for coal seam gas well head emissions detection and reporting

Version 2 - June 2011

Queensland Government

Development of this Code
This document has been developed at the request of the Department of Employment, Economic Development and Innovation Petroleum and Gas Inspectorate to provide a consistent industry approach to wellhead leak testing, reporting and remediation.

The Code was developed by an industry working group from October 2010 through to March 2011 and has been overseen and endorsed by the Inspectorate. The Code has been called up in the Petroleum and Gas (Production and Safety) Regulation 2004 as a preferred standard.

The Code will be reviewed by an industry working group within 24 months.

Version 2 makes changes to include notification requirements to landholders. – Published 23June 2011 and effective 1 July 2011.

Contents

Introduction

Coal Seam Gas (CSG) is an important energy source for Queensland and supplies around 80% of reticulated gas for Queensland's domestic, commercial, manufacturing and industrial needs. It is piped throughout most of Queensland's major cities and is essential to the State's economy. CSG or natural gas (as it is commonly known) is commonly considered as the safest form of reticulated energy used for domestic purposes. Natural gas is also reticulated throughout almost every major city in the world and is relied upon to drive economic growth.

CSG is a natural gas (consisting almost entirely of methane) that is currently being extracted from coal seams in the Bowen and Surat Basins in Queensland. Natural gas, either produced from traditional natural gas wells or CSG wells can be liquefied and transported by ship to provide an important income for the state and provide considerable employment for both regional and metropolitan based workers.

CSG wells and their associated facilities are rated as low risk for emissions due to rigorous design standards, robust safety obligations and strong governance programs. While CSG operators have their own operating procedures with regard to well head emission classification and detection, this Code of Practice provides a consistent best practice minimum standard for identifying, classifying, rectifying and reporting well head gas emissions.

CSG is extracted from an increasing number of unmanned gas wells connected to a network of underground gathering pipelines. Gas is then filtered, compressed and dehydrated before being piped to market via cross country transmission pipelines. As CSG wells are generally located on grazing or cultivated land, land owners and occupiers have raised concerns about how the CSG industry identifies and manages potential gas leakage at CSG well site facilities.

The *Petroleum and Gas (Production and Safety) Act 2004* (P&G Act) requires CSG operators to apply a rigorous, risk based approach to the safety of operations and possess a comprehensive asset integrity regime to minimise risks associated with the development and operations of CSG infrastructure. Compliance with this legislation will result in an extremely low level of risk from gas emissions at CSG well sites.

The reporting resulting from this Code of Practice will ensure that the Petroleum and Gas Inspectorate (P&G Inspectorate) within the Department of Employment, Economic Development and Innovation (DEEDI), as the gas safety regulator, is appropriately informed and the performance of the CSG industry's performance on gas emission management is appropriately measured.

Objective

The objective of this Code of Practice is to set a standard:

1. methodology to detect gas leaks,
2. procedure to classify and action reportable leaks, and
3. notification procedure to the P&G Inspectorate for reportable emissions.

Purpose of the Code

This Code of Practice standardises the detection, remediation and reporting of gas emissions from CSG well site facilities, and places particular emphasis on community safety.

The Code is designed to be considered and used in conjunction with the CSG Operators internal risk assessment processes and operating procedures under their safety management systems. It adopts a standard process for monitoring, identifying and managing gas leaks from CSG well site facilities in Queensland. The Code ensures that emissions associated with gas leaks are identified, responded to and classified in a consistent manner, and that wells are monitored effectively by the CSG Operators.

The Code will help to ensure that:

1. risk to the public and CSG workers is managed to a level that is as low as reasonably practicable;
2. regulatory and applicable Australian Standard requirements, as well as the Operator's internal requirements are understood and implemented; and
3. the life of CSG well site facilities is managed effectively through timely leak repair and periodic survey.

Scope

This Code of Practice applies to all CSG operators in Queensland.

Responsibilities

The CSG operator as defined in Appendix II and consistent with section 670 (6) and section 673 of the P&G Act, shall be accountable to ensure compliance with this Code of Practice.

Relevant industry standards

There is currently no standard specifically for the identification and management of leaks in petroleum 'upstream' or CSG facilities.

However, AS/NZS: 4645.1:2008 'Gas distribution Network - Network Management' standard describes operational and leakage management obligations for natural gas distribution networks in CBD and metropolitan areas of all Australian and New Zealand cities. This urban environment provides greater risks and consequences for leaks than the rural gas field environment, and sets a high benchmark for the management of leaks for the CSG industry.

Therefore, this standard has been adopted as the basis for this Code of Practice, as it represents the most relevant and stringent standard to apply to identifying, classifying and managing gas leaks in rural gas fields. This Code of Practice has been drafted to meet or exceed the requirements of the *AS/NZS: 4645.1:2008*'Gas distribution Network - Network Management' standard.

This Code of Practice similarly adopts a conservative approach to the classification of reportable leaks. Under this Code, a threshold gas content of 10% Lower Flammable Limit (LFL) lower limit has been set for reportable leaks. The term LFL is explained in the following section on CSG safety.

This sets a more rigorous standard than the personal lower limit level of 20%-25% LFL commonly used by gas and emergency workers responding to or potentially exposed to gas leaks. This does not mean that the risk of gas emissions is greater in gas fields; rather it means that a more stringent monitoring regime has been put in place in order to meet community expectations and ensure community confidence in the leak monitoring and gas field safety regime.

A standard leak measuring methodology has been adopted for the industry under this Code of Practice. This methodology requires gas/air content to be measured at 150mm from source, with all leaks above 10% LFL being reportable. This exceeds the current standard level of 20% LFL at 200mm distance used by some major operators in gas processing plants which have significant gas infrastructure often in confined spaces.

General CSG safety

CSG is a safe energy source that is a by-product of the natural conversion of plant material to coal. CSG consists mostly of methane which, like other forms of natural gas, can be used as a fuel in heaters, stoves and hot water systems in homes and businesses. Methane is non-toxic and is only flammable when the gas concentration is between 5% and 15% per cent of the total gas/air mixture. CSG is lighter than air, meaning it will rise naturally and quickly dilute and dissipate into the air in an outdoor environment. In addition to its application in domestic and business environments, natural gas is safely used in many other areas including transport fuels and as feedstock or fuel for industrial plants.

CSG well site facilities are constructed to Australian or International Standards where applicable. These facilities are pressure tested prior to commissioning to verify the integrity of the facilities and the CSG operators conduct routine monitoring to ensure ongoing safe operation of the facilities.

For CSG to reach a flammable state, it must first form a concentration level of between 5% and 15% of gas in air. A typical potential gas leak at a well head site is likely to emanate from a gas flange or screwed joint. This type of leak is generally insufficient to support combustion.

The lower explosive limit (LEL) or lower flammable limit (LFL) of a combustible gas describes the smallest amount of gas that supports a self-propagating flame when mixed with air (or oxygen) and ignited. In gas-detection systems, the amount of gas present is specified as a percentage (%) LFL.

Zero percent (0%) LFL denotes an atmosphere that is free from a combustible gas. One hundred percent (100%) LFL denotes an atmosphere in which the gas concentration has reached its lower flammable limit. The relationship between percentage LFL and percent by volume differs from gas to gas (for example liquid petroleum gas (LPG) has a different LFL to CSG).

This Code of Practice describes the actions that CSG operators must undertake for leaks that have measured gas concentrations as low as 10% LFL, which is an order of magnitude less than a flammable concentration. A 10% LFL is a very conservative standard and leaks of lower concentration of methane in an open air rural gas field environment are not regarded as a significant risk.

Appendix 1 provides a comparison of the properties of CSG compared with LPG.

Definitions

Definitions for terms used in this Code of Practice are outlined in **Appendix 2**.

Code of Practice operational requirements

At a minimum, CSG Operators must comply with the following requirements to ensure that risks from gas leaks at CSG well site facilities are reduced to as low as reasonably practicable.

Risk assessment

CSG operators must carry out a risk assessment to identify the risks posed by leaks from CSG well site facilities and implement appropriate actions to reduce those risks to as low as reasonably practicable as required under the P&G Act.

As part of their safety management plan as required under the P&G Act, each CSG operator must develop a risk-based management plan ("Leak Management Plan") for leaks from CSG wells and CSG well site facilities to ensure that emissions are:

1. Identified;
2. Classified'
3. Controlled (e.g. isolated, rectified, monitored) as determined by considering the risk and determining the appropriate controls, and
4. Reported,

and there are systems in place and initiated to ensure the control actions are completed.

This Code does not remove the obligation for adequate risk assessment and management to be undertaken.

Inspection frequency and procedure

CSG operators must undertake routine visits to operational CSG well site facilities on a regular basis in accordance with their operating and maintenance plans.

CSG Operators must at a minimum:

1. Ensure that CSG well site facility production operators carry and monitor personal calibrated gas detectors during every routine operational visit to CSG well site facilities.
2. Ensure that CSG well site facility production operators are properly trained and competency-assured to identify gas leaks detected by their personal gas monitors, and to take appropriate actions in line with this Code of Practice, during routine operational visits to CSG well site facilities.
3. Ensure that CSG well site facility production operators use calibrated gas monitors to investigate and classify any audible leaks at CSG well site facilities, and that the appropriate actions to manage those leaks are taken in line with this Code of Practice.
4. Ensure formal integrity audits are conducted on 20% of the total number of CSG well site facilities per annum.
5. Ensure a formal integrity audit is conducted on every operating CSG well site facility at least once every five years.
6. Undertake formal integrity audits on individual CSG well site facilities at an increased frequency as determined by the risk assessment and in consideration of previous audit/inspection findings for those specific facilities.

Standard leak classification

The following standard gas leak classification definition has been adopted and requires reportable leaks to be notified to the P&G Inspectorate.

"**A Well Head Reportable Leak**" is defined as:

1. An emission due to an unplanned release from a CSG well site facility that, at a measurement distance of 150mm immediately above (and downwind) and surrounding the leak source in an open air environment above ground position; gives a sustained LFL reading greater than 10% of LFL for a 15 second duration.

2. The following incidents/circumstances also fall under the definition and require CSG operators to notify the P&G Inspectorate:
   a. an unplanned hydrocarbon gas release reported by the emergency services, a public authority or member of the general public;
   b. an unplanned hydrocarbon gas release resulting in an incident involving fire or injury;
   c. an unplanned hydrocarbon gas release which receives media attention, and
   d. an unplanned release with the potential for significant escalation close enough to a building or other confined space and large enough that gas is likely to enter any building or confined space.

An unplanned gas release that falls outside of the above parameters will be classified as an "**Internally Reportable Well Head Leak**" and will be subject to reporting procedures and rectification treatment in accordance with an individual company's leak management plan and other safety management plan risk-based assessments and requirements in other safety management plans.

Standard leak detection methodology

A suitably trained and competent field technician will survey for gas leaks by placing the probe of the gas detector immediately adjacent to but not touching (approximately 10-20mm away) all potential sources of leakage at the well facility.

Should an indication of gas be found, the field technician will:

1. Record the % LFL or % methane sustained for 15 seconds.
2. After complying with the detector's manufacturer's instrument instructions for retest (eg a purge in clean atmosphere), the field technician shall retest a distance of 150mm from the leak source in all directions and determine the highest leak zone (potentially immediately above and in a downwind situation from the source).
3. The highest confirmed % LFL of gas sustained for 15 seconds with the gas probe held at 150mm from the potential source must be recorded.
4. The source of leak must be clearly identified and recorded.

A reportable well head leak is defined in the *Standard leak classification* section above.

This standard exceeds currently accepted industry standards of detection in higher risk environments such as large scale semi enclosed gas processing and refining plants.

Tester and instrument certification

All gas leak surveys will be conducted by trained personnel using industry-accepted gas detection instruments calibrated by certified testers (ie NATA approved) in accordance with the manufacturers requirements. Gas detectors must be maintained and tested in accordance with manufacturer's instructions, and be capable of testing to a low reading of 1% LFL and have sensitivity of +/-0.5% LFL.

Remediation and notification

Reportable leaks

In the event that a CSG operator detects a **"Well Head Reportable Leak"** at a CSG well site, the CSG operator must:

1. Comply with the CSG operators safety management system requirements for risk assessment and emergency response;

2. Immediately establish an exclusion zone around the leak and impose appropriate restrictions on access to the exclusion zone, along with any other necessary immediate controls;

3. Immediately notify any leaks at or over the LFL (i.e. 100% LFL or greater at 150mm from the leak source) to the P&G Inspectorate via their 24/7 emergency numbers (see Appendix 3).
    a. This notification must include the date of identification, nature and level of leak, wellhead name, number and location as well as initial steps taken to minimise the risk.
    b. Leaks over LFL must be repaired or made safe as soon as practicable immediately after detection.

4. Immediately:
    a. Notify the land owner or occupier of the property on which any uncontrolled leaks from CSG well site facilities and related infrastructure (of 100% LFL or greater at 150mm from the leak source) are identified.
    b. If the reportable leak zone (gas concentrations greater than 10%LFL) from an uncontrolled leak is or is likely to impact on adjoining properties then the landowner(s) or occupier(s) of those properties must also be notified.

Note: Step 2 and step 3b – in terms of immediately safely making the site safe take priority over steps 3a and 4 and complying with steps 3a and 4 must not compromise, impair or delay the operator's actions to immediately make the site safe and establish exclusion zones.

5. Notify the Petroleum and Gas Inspectorate in writing within 24 hours of the detection of any leak within the reportable leak range (10% LFL and above). This notification is to be made via the gasafe email (gassafe@dme.qld.gov.au) and must include the date of identification, nature and level of leak, wellhead name, number and location.
    a. Ensure that the gas leak is isolated, repaired (if possible), contained or otherwise made safe within 48 hours of detection of the leak.
    b. In the event of this deadline being unachievable, the CSG operator must notify the P&G Inspectorate of the reason for the delay and provide a target date for completion of the work.

6. Remediation work must be conducted as follows:
    a. Only commence work after a suitable risk assessment has been undertaken and relevant safety procedures are followed including consideration of all the required Personal Protective Equipment (PPE) and emergency response materials.

b. For leaks identified on well equipment - higher order controls, such as containment by repair, must be implemented wherever possible.
c. For leaks identified on well casings or adjacent to the well casing (where a work over rig is necessary to affect repair) - determine whether the leak requires immediate repair, or whether the risk can be adequately managed via other control measures until a work over of the well is scheduled for normal operational reasons. The risk assessment to determine the above must consider the location of the well, likely access to the well from landholders or the general public, and landholder/community concerns in relation to the leak.

7. Provide a written close-out report to the P&G Inspectorate within 96 hours of detection of the leak, specifying the date of identification, nature and level of leak, location and name of the well, the rectification actions taken or proposed and the current status of the leak (e.g. isolated, repaired, etc).

8. If remediation is delayed for any reason then a final close out report must be provided when all work is completed.

The P&G Inspectorate may upon review of the report and risk assessment require further information or action in accordance with its enforcement policy and regulatory role.

Extensions

If a risk assessment determines that the risks of immediately repairing a leak exceed the risk posed by the leak, this can be considered as grounds for extension of the 48 hour remediation period, provided that other measures to mitigate the risk are undertaken (e.g. ensuring no ignition sources or personnel are permitted in the exclusion zone). The P&G Inspectorate must be notified (before the expiry of the 48 hour remediation period) of the proposed delay.

Internally reportable leaks

In the event that a CSG operator detects an **"Internally Reportable Well Head Leak"** (see definitions) at any CSG well site facility, the CSG operator must promptly respond in accordance with the actions specified in the relevant CSG operator's 'Leak Management Plan' and other safety management plan requirements.

On an annual basis (via the annual safety report), a summary of all well head reportable leaks and internally reportable leaks must be provided to the P&G Inspectorate.

Protection of CSG well site facilities

Appropriate signage, barriers and/or security fencing to isolate CSG well site facilities must be in place for all well site facilities as determined by the CSG operators risk assessment and management. The risk assessment must be consistent with AS/NZS:60079 Explosive atmospheres Part 10.1:2009 and will consider:

1. Risks posed by third parties and the general public based on proximity of the CSG well site facilities the ownership of land, and the accessibility of the CSG well site facilities to the general public; and
2. The magnitude of the risk posed by the CSG well site facilities, which may be dependent on the type of well completion the equipment/facilities installed at these sites and the pressure, flow rate and composition of the gas contained by the facilities.

CSG operators must ensure that all required fencing and signage is in place after the well is drilled and also after surface equipment is installed.

The perimeter of all barrier fencing must be placed no closer than the appropriate classified hazardous area zone.

Review of this Code of Practice

This Code of Practice will be subject to review and revision every 24 months or in the event of significant change to operations or regulatory requirements.

Appendix 1 — Gas comparison table

The table below compares the specific gravity, energy content and the PPM (parts per million) values corresponding to 100%, 10%, 5% and 1% LFL readings for CSG (methane) and LPG respectively.

The table provides a comparison of the different measurement units (LFL and PPM) and demonstrates that compared to LPG, which is a gas in common domestic use, CSG/methane represents a much lower risk although both gases when managed appropriately are safe to use.

For example, the gravity for CSG/methane is much less than one, indicating that methane will rise and disperse into the atmosphere when released and will not form pools at ground level as in the case of LPG.

The heating value of LPG is much higher than CSG/methane, meaning LPG emits more energy per cubic metre of gas when it is burnt.

The PPM values indicate that LPG has a greater risk of flammability even at substantially lower levels of gas concentration in air.

This table is for informative purposes only.

Gas Comparison Table

Gas	**Specific Gravity** [note 1, 3]	**Heating Value (mJ/m^3)** [note 2,3]	**PPM at LFL**	**PPM at 10% LFL**	**PPM at 5% LFL**	**PPM at 1% LFL**
Methane (CSG)	0.554	38.7	53,000	5,300	2,650	530
LPG (typical)	1.609	95.5	21,000	2,100	1,050	210

Notes: [1] Specific gravity is the density of the gas relative to air. Values greater than one indicate that the gas is denser than air and can accumulate at ground level to form pools. Values given are at normal atmospheric temperature and pressure — 20°C and 1 atmosphere respectively.
[2] Approximate gross heating value.
[3] Values in columns 2 and 3 are an average calculated from maximum and minimum Australian pipeline quality natural gas specifications.

Appendix 2 — Definitions

Well Head Reportable Leak is defined as:

1. An emission due to an unplanned release from a CSG well site facility that, at a measurement distance of 150mm immediately above (and downwind) and surrounding the leak source in an open air environment above ground position; gives a sustained LFL reading greater than 10% of LFL for a 15 second duration.

2. The following incidents/circumstances also fall under the definition and require CSG operators to notify the P&G Inspectorate:

   a) an unplanned hydrocarbon gas release reported by the emergency services, a public authority or member of the general public;
   b) an unplanned hydrocarbon gas release resulting in an incident involving fire or injury;
   c) an unplanned hydrocarbon gas release which has media attention, and
   d) an unplanned hydrocarbon gas release with the potential for significant escalation close enough to a building or other confined space and large enough that gas is likely to enter any building or confined space.

Internally Reportable Well Head Leak is defined as:

Any leak of gas from a CSG well site facility that falls outside of the above definition of wellhead reportable leak. These leaks will be subject to reporting procedures and rectification treatment specified by each CSG operator's procedures and risk based assessments.

CSG Operator is defined as:

The company that is responsible for the safe operation and management of CSG authorised activities on Authorities to Prospects (ATP's), Petroleum Lease Applications (PLA's) or Petroleum Leases (PL's) under section 670(6) of the P&G Act. The operator is defined under section 673 of the P&G Act.

CSG Well is defined as:

A well that is constructed to allow gas from coal seams to migrate into the well, and which may contain pressurised hydrocarbon gas (eg methane).

CSG Well Site Facility is defined as:

The above ground equipment located in the immediate proximity of a CSG well and connected to that CSG well, which contains or may contain pressurised hydrocarbon gas. It includes the well head, pumping equipment, the production separator and interconnecting pipe work and fittings.

Leak Management Plan is a plan that is part of the CSG operator's safety management plan for leaks from CSG wells and CSG well site facilities to ensure that emissions are:

1. Identified;
2. Classified;
3. Controlled (eg isolated, rectified, monitored) as determined by considering the risk and determining the appropriate controls; and

4. Reported

and there are systems in place and initiated to ensure the control actions are completed.

Routine Operational Visit is defined as:

A routine check or visit by production operators to complete an operational check or complete planned or unplanned maintenance. These visits can include normal operational functions for example checking filters, drains etc.

CSG well site facility production operators must carry and monitor personal calibrated gas detectors during every routine operational visit to CSG well site facilities.

Formal Integrity Audit is defined as:

A formal inspection of the integrity of a CSG well site facility. This inspection is required by the CSG operator's asset integrity process and details the condition of the CSG well site facility compared with it's original design and operability specification. This audit should be completed by a competent person and would make observations on the integrity and quality of existing CSG well site facility. This audit will include (as a minimum), a comprehensive leak survey of all components of the CSG well site facility.

Appendix 3 — Petroleum and Gas Inspectorate contact details

Email: gassafe@dme.qld.gov.au

24/7 Emergency numbers for immediate reporting requirements:

Southern region: 0419 888 575
Central region: 0418 888 575
Northern region: 0409 896 861

General contact details:

Southern region:	3238 3782
Central region:	4938 4683
Northern region:	4760 7402
Head office :	3237 1626

Reference: QCQGC-BX00-GPA-LTR-000001

A BG Group business

9 September 2011

Committee Secretary
Senate Standing Committee on Rural Affairs Transport
PO Box 6100
Parliament House
Canberra ACT 2600
Australia

Dear Sir/Madam

As requested, please find attached QGC's response to the committee's questions of 29 August 2011.

The committee wrote:

The various bans on using BTEX chemicals in fracking don't extend to banning the BTEX contained in the mechanical lubricants needed for the operation of the CSG wells. Following the reports in the media with regard to the presence of BTEX chemicals in bores at Arrow energy sites in Queensland, it would assist the committee if you could provide answers to the following questions:

- *Are you able to advise what quantities of lubricants/operation-related BTEX is being used per well, and what is currently done to ensure these chemicals are isolated from the soil/ groundwater?*

QGC response:

In constructing coal seam gas wells lubricants (hydrocarbon-based greases) are used when screwing together threaded joints of casing pipe. The lubricant is a necessary component in the construction of wells as it prevents thread galling and also seals the roots of threads. Typically less than 20 litres of lubricant is used in a 750m well which would comprise about 50 lengths of threaded casing pipe. The design of the screwed connection results in very little of this lubricant being smeared on the external diameter of the casing pipe when joints are screwed together. Once the casing pipe has been screwed together cement is then pumped and placed in the space between the outside of the casing pipe and the inside of the hole that has been drilled. It is this cement that provides a seal between the soil and groundwater and the outside of the casing pipe so preventing any exposure pathway existing between any residual lubricant and adjacent soil or groundwater.

- *Particularly, is the amount involved comparable/ miniscule compared to the quantities that would be used in fracking?*

QGC response:

QGC does not use petroleum compounds containing BTEX in hydraulic fracturing. This is fully in line with the Queensland Government's restriction on these compounds for hydraulic fracturing in coal seam gas wells announced in August 2010.

- *What quantity of concentration in groundwater would you need from a leakage of these chemicals for it to be a health or environmental risk.*

QGC response:

Like farmers who use chemicals on crops, QGC uses chemicals with extreme care.

Operating procedures, well construction and water handling processes are designed to ensure that our operations pose no significant risk to the environment or people.

In line with the well construction methodology defined in response to the first question there does not exist an exposure pathway for any excess lubricant to contact the soil and groundwater once the casing pipe is separated from the soil and groundwater through the pumping and placement of cement in the space between the outside of the casing pipe and the inside of the hole that has been drilled.

- *What mechanisms (and additional redundancies) are currently taken to protect against contamination risks?*

QGC response:

QGC constructs wells in accordance with what is termed "Good Oilfield Practice". Good Oilfield Practice combines Government regulations, international best oilfield practice, and company policies, processes and procedures, all of which are monitored and regulated by Government. Fundamental to well construction is the protection of soil and groundwater and this is achieved through internationally standardised drilling, casing, and cementing practices that ensure that all well fluids that travel through the inside of the casing pipe from the reservoir to surface are separated from soil and groundwater by casing pipe that has cement pumped around it.

- *Do you have any data on the naturally-occurring levels of these chemicals in your area of operation?*

QGC response:

Since the Queensland Government's restrictions on BTEX were announced and monitoring was required, QGC has detected no BTEX in its producing wells or ponds.

Yours sincerely

Rob Millhouse
General Manager, Government Affairs
QGC Pty Limited