ACIL ALLEN CONSULTING

REPORT TO
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CARMICHAEL - ABBOT POINT RAIL:

FINANCING ISSUES FOR NORTHERN AUSTRALIA INFRASTRUCTURE FACILITY

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ACIL ALLEN CONSULTING, CARMICHAEL-ABBOT POINT RAIL: FINANCING ISSUES FOR NORTHERN AUSTRALIA INFRASTRUCTURE FACILTY, JULY 2017

C O N T E N T S

INTRODUCTION 1

In October 2010, Adani Mining Pty Ltd (Adani), a wholly owned subsidiary of the Indian-based Adani Group, commenced the process of seeking environmental approvals and mining leases for the Carmichael thermal coal project in the northern part of the Galilee Basin in Queensland. At that time, prices of internationally-traded thermal coal were close to historically high levels.

The benchmark Newcastle thermal coal price peaked at US$160 per tonne f.o.b. in January 2011 (real 2017 US$). Over the next five years, the benchmark thermal coal price exhibited a marked downtrend. In January 2016, thermal coal prices were below US$50 per tonne.

In the second half of 2016, thermal coal prices rose sharply in response to government-mandated cuts to Chinese production in the context of a spike in summer demand and weather-related supply disruptions. The Newcastle benchmark price peaked around US$110 per tonne f.o.b. in the middle of the fourth quarter of 2016. After the Chinese Government eased production restrictions, the price began to slide again. It was around US$84 per tonne at the end of February 2017, just under US$75 per tonne on 31 May 2017, and recovered to around US$78.50 per tonne late in June 2017.

During the past seven years of coal price turmoil, Adani has doggedly sought environmental approvals, mining leases and finance to allow the Carmichael project to proceed. These requests have been opposed through persistent, strong public campaigns and litigation by groups concerned about local and global environmental impacts of extraction and combustion of thermal coal from the Carmichael operation, and expansion of coal handling facilities at the Abbot Point port.

In the meantime, spokespersons for the Queensland and Commonwealth Governments and local government authorities have expressed strong support for the Carmichael project on grounds it would provide regional jobs and government revenue. In the 12 months to the end of March 2017, Adani obtained government approval for the issue of mining leases, a rail line from the mining leases to Abbot Point, and development and operation of a new coal terminal at Abbot Point. These approvals were subject to multiple environmental conditions. In addition, in May 2017, the Queensland Government and Adani reached agreement on a deferred royalty arrangement, but the parties did not disclose details on grounds that they were “commercial-in-confidence”. Also, since December 2016, the former Commonwealth Minister for Resources and Northern Australia (Matthew Canavan) publicly supported provision of a Commonwealth loan on concessional terms to Adani to help finance the rail link, arguing it would facilitate development of the Galilee Basin.

The main Queensland and Commonwealth parliamentary opposition parties have expressed varying levels of support for the Carmichael project. The Queensland opposition, the Liberal National Party, urged the government to assist Adani through a concessionary royalty arrangement. However, the Commonwealth opposition Labor Party has opposed the provision of a concessional loan to help finance the rail link.

The task of securing finance for the Carmichael coal mining operation and supporting infrastructure has been very difficult. Adani has not yet been able to secure sufficient finance. In May 2017, Adani described a loan it had sought from the Commonwealth Government’s Northern Australia Infrastructure Facility as critical to the project. Adani’s target date for settlement of a financing package is the end of 2017.

The Australian Conservation Foundation (ACF) engaged ACIL Allen Consulting Pty Ltd (ACIL Allen) to assess the rationale for provision of a Commonwealth Government loan to Adani for the railway line to Abbot Point, and the risk to taxpayers of the loan not being repaid with interest. ACF and ACIL Allen agreed that ACIL Allen’s assessment would be independent.

Section 2 provides an outline of the proposed mining operation, and supporting infrastructure. It also briefly discusses financing issues. Section 3 provides information about the purpose and activities of the Northern Australia Infrastructure Facility, which is considering an application from Adani for a loan to help finance the proposed Galilee Basin-Abbot Point rail link. In section 4, issues associated with debt financing of the Carmichael Mine and supporting infrastructure are reviewed. Also, section 4 discusses the rationale for financing of the rail line by the Northern Australia Infrastructure Facility and issues that will have to be addressed by that entity in its assessment of Adani's loan application. Section 5 presents perspectives of credible entities on the price outlook for thermal coal. Concluding remarks are presented in Section 6.

CARMICHAEL COAL MINE AND ASSOCIATED INFRASTRUCTURE 2

2.1 Key Elements of Carmichael Project

The proposed Carmichael coal mining project is located approximately 160 km north-west of Clermont and around 180 km west of Moranbah in Queensland. Adani plans to produce 60 million tonnes of coal per year from the Carmichael project over a period of 60 years. It would involve six open-cut and five underground mining operations plus processing facilities and supporting infrastructure. If the proposed project and scale of operations are realised, the Carmichael project would be Australia's largest coal mining operation and the world's largest coal export project.

The proposed supporting infrastructure includes expansion of coal handling facilities at the existing Abbot Point Port (25 km north-west of Bowen). It also includes a new 388-km standard gauge railway line linking the mining leases to Abbot Point.

Adani acquired a 99-year lease of the existing coal terminal at Abbot Point from the Queensland Government-owned North Queensland Bulk Ports (NQBP) in 2011. Adani has been working with NQBP to plan the T0 terminal that will provide additional capacity to accommodate Carmichael coal.

The initial stage of the T0 terminal development will have a capacity of around 35 million tonnes of coal per year based on one coal in-loading and one out-loading stream. A second stage will add a second coal in-loading and out-loading stream, lifting capacity of the T0 terminal to 70 million tonnes per year. Adani will also fund dredging of 1.1 million tonnes of seabed material at Abbot Point. The material will be placed on vacant land adjacent to the existing coal terminal and may be used to support future expansion of the port. The activities at Abbot Point have been given government approval, subject to environmental conditions.

The rail link comprises the 78-km Carmichael rail project from the mining and processing operation to Mistake Creek, and the 310-km North Galilee Basin Rail (NGBR) project from Mistake Creek to Abbot Point. The NGBR facility will be accessible by other enterprises.

The rail link would have an initial capacity of 40 million tonnes per year and an ultimate designed capacity of 100 million tonnes per year. The cost of the Carmichael and NGBR rail projects is estimated to total of the order of $2.75 billion (based on the $2.2 billion reported cost of the NGBR), and the total cost of the mine, rail and port facilities and other associated infrastructure has been reported to be around $21.7 billion.

2.2 Financing the Project

The task of securing debt and equity finance for a $21.7 billion project is extremely demanding. It is understood that Adani has not yet secured sufficient funding. Adani has nominated the end of 2017 as the target date for finalising the funding package.

Adani has sought a concessional loan of up to $1 billion from the Commonwealth Government's Northern Australia Infrastructure Facility (NAIF) to help finance the NGBR project. The former Commonwealth Minister for Resources and Northern Australia has publicly supported development of the Carmichael project and provision of a loan by the NAIF to help finance the NGBR (Ludlow. 2017).

It is understood that Aurizon has applied for finance from the NAIF for a competing rail project. Aurizon has proposed a narrow gauge rail link between the Galilee Basin and the existing Bowen Basin narrow gauge rail network. This would allow coal to be transported to ports at Abbott Point and Hay Point. The reported cost of the facilities proposed by Aurizon is $1.25 billion and the reported amount of the loan application is $350 million (Ludlow, Ker, 2017).

The NAIF is currently assessing the Galilee Basin rail applications, along with other requests for finance for infrastructure in northern Australia. Decisions are expected by the end of 2017.

The difficulty Adani has experienced in financing the project may relate to the amount of finance required and to the expected profitability of the project. Without detailed information on the proposed staging of the mine and infrastructure, how they will evolve over time, and the cost structure of the project as development and operations evolve, it is not possible to make judgements on the profitability and “bankability” of the project. However, one thing is clear. The substantial decline of thermal coal prices since 2011 has stripped in excess of $A40 per tonne from profit (after adjusting much larger US$ price declines for depreciation of the $A). This has raised doubts about the likelihood of any significant surplus of revenue over full costs (including a reasonable risk-adjusted rate of return on investment) in medium- and long-term timeframes.

NORTHERN AUSTRALIA INFRASTRUCTURE FACILITY: OBJECTIVES, INVESTMENT MANDATE, AND RISK BEARING 3

The NAIF was established as of 1 July 2016, pursuant to the *Northern Australia Infrastructure Facility Act 2016*. It has an independent board. The Export Finance and Insurance Corporation (Australia's export credit agency) will provide administrative and credit assessment services. The NAIF has $5 billion available for allocation over 5 years.

3.1 Objectives

The stated objectives of the NAIF include:

– provision of financial support for establishment of economic infrastructure that enables longer-term expansion of industry and population in northern Australia and provides future economic benefits
– acting as a catalyst for private sector investment in northern Australia
– operating in partnership with commercial lenders, rather than in competition with them.

3.2 Investment Mandate Direction

The board's decisions regarding provision of financing support must be made in accordance with an investment mandate direction issued by the Minister for Resources and Northern Australia. Key elements of the direction issued under sub-section 9(1) of the *Northern Australia Infrastructure Facility Act 2016*.are as follows.

– Loans will be the default financing mechanism, but alternative mechanisms (excluding equity) may be deployed with the agreement of the Minister.
– A financing mechanism may be provided only if the board is satisfied the project to be financed by NAIF would not otherwise have received sufficient financing from other sources.
– The board must be satisfied there is an expectation that either the Commonwealth will be repaid sufficient to cover NAIF's administration cost and the Commonwealth's cost of borrowing or the investment can be refinanced.
– A necessary condition of provision of a financing mechanism is that it encourages private sector participation in financing of the project.
– A diversified portfolio of investments is preferred.
– In determining any concessionary aspects of a financing mechanism, the board must have regard to the extent of the "public benefit" provided by the project and the extent and mix of concessions necessary for the proposed project to proceed. Concessions must be limited to the minimum necessary for a project to proceed.
– Concessions may include:
  - longer loan tenor than offered by commercial financiers, but not longer than the maximum length of Commonwealth borrowings (currently 30 years)
  - lower interest rates than offered by commercial financiers, but not lower than the Commonwealth borrowing rate
  - deferred or other tailored loan repayment schedules
  - lower fee structures than offered by commercial financiers
  - permitting loans from the Commonwealth to rank lower than those provided by commercial financiers.
– Finance may be provided on a limited-recourse basis (loan security confined to project assets). Decisions on whether more security will be required by NAIF are to be determined on a case-by-case basis.
– Seven eligibility criteria must be met:

  - provision of increases in capacity of physical economic infrastructure
  - provision of “public benefit”, preferably through capacity to serve multiple users, and benefits beyond those able to be captured by the proponent
  - “significant benefits” flow to northern Australia
  - financial assistance is necessary to enable a project to proceed or proceed earlier
  - the NAIF financing mechanism provides no more than 50 per cent of total debt in respect of the proposed project
  - the proponent demonstrates to the NAIF board the ability of the project to repay the debt in full and on time or to support refinancing
  - provision of a strategy for Indigenous procurement and employment in the region.
- Preference will be given to projects meeting one or both of two non-mandatory criteria:
  - minimum financing of $50 million from NAIF
  - an infrastructure need has been demonstrated by a Commonwealth, state or territory assessment process.
- The NAIF is required by the investment mandate to develop a Risk Appetite Statement (RAS), in consultation with the Minister and relevant jurisdictions in northern Australia, to guide its investment decisions. The RAS may have regard to a preference for a diversified portfolio, and may have a high risk tolerance in relation to factors unique to investing in economic infrastructure in northern Australia. The RAS has not been made publicly available.

3.3 Observations Regarding the NAIF Investment Mandate

To be eligible for concessionary finance from NAIF, a project must produce “public benefit” and “significant benefits to Northern Australia”. Preference will be given to projects that produce benefits beyond those that can be captured by the proponent. In determining concessions, the board of NAIF must have regard to “the extent of the project’s public benefit”.

The investment mandate direction does not provide guidance on what is meant by the term “public benefit”, how “public benefit” should be estimated, and what amount of benefit should be regarded as significant. Also, the direction does not indicate whether “public benefit” refers to gross benefit (ignoring costs) or to nett benefit (after deducting costs, including external costs such as environmental damage). Moreover, the investment mandate is silent on consideration of risk and uncertainty (types of cost) associated with projects and who will be required to bear the burden. The accepted economic approach is to focus on nett benefits, including consideration of risk and uncertainty and crowding-out effects.

It appears that benefits accruing to northern Australia have to be “significant”, but those accruing nationally do not. “Significant benefits to northern Australia” could be achieved without national “public benefit” by transfers to the proponents of northern projects at the expense of southern residents and by ignoring costs (including crowding-out effects and environmental impacts) associated with projects. The lack of clear guidance to NAIF on benefits and consideration of costs could mean that projects without nett benefits from a national perspective are subsidised by taxpayers.

The investment mandate direction does not require consideration of the distribution of benefits and costs associated with a project. Indeed, the point made above regarding the distinction between “public benefit” and “significant benefits to northern Australia” means the guidelines facilitate neglect of the important matter of distribution. The accepted economic approach is to document how benefits and costs are distributed.

It is not clear from the direction how NAIF should translate the perceived extent of public benefits into financing concessions for projects. NAIF has not revealed publicly how it intends to do this.

Projects financed by NAIF will be those perceived by commercial financiers in general to involve particularly high risk of failure to repay the loan and interest in full. Indeed, before providing a financing mechanism, the board of NAIF must be satisfied that a project would not otherwise have received sufficient financing from commercial sources. However, the board is also required to be satisfied “there is an expectation that the Commonwealth will be repaid, or that the investment can be refinanced; and that any return will cover at least the Facility’s (NAIF’s) administrative costs, and the

Commonwealth's cost of borrowing." This is a very vague expression because of the way the term "expectation" is used. It is not clear who should hold this "expectation" and what degree of certainty of repayment the board of NAIF should hold for it to judge that an "expectation" of repayment exists.

To support a project, it seems that the board of NAIF will have to make one of two judgements. First, it may judge that all commercial financiers that won't support the project on any terms have overstated the credit risk associated with the project. Second, the board may judge that the "public benefits" from the project will be sufficient to justify imposition of credit risk on taxpayers, but it will still have to perceive that there is an "expectation" of repayment, whatever that means. Either way, Australian taxpayers will have to bear the risk associated with a judgement call by the NAIF board to help finance a project that could not be financed commercially.

NAIF's Risk Management Framework[1] sets out a broad approach to management of risk across NAIF, but does not explain NAIF's process for assessing credit risk associated with provision of financing mechanisms to individual projects. However, the document expressed the board's position on acceptance of risk on behalf of taxpayers (NAIF, 2017):

"NAIF has a high financing risk tolerance to complement and encourage ("crowd in") private sector participation in financing a project, which may include a high risk tolerance for concessions in relation to tenor, pricing, repayment terms, cash flow priority, and willingness to partner with commercial and other financiers. NAIF also has a high risk tolerance for risk factors that are unique to investing in Northern Australia, including but not limited to distance, remoteness and climate. The Risk Appetite Statement accepts that during the initial years of NAIF's operation, the portfolio of NAIF's investments may have high concentration risk. The board is to have regard to a preference for a diversified portfolio including industry and geographic spread across the Northern Australia States and Territory. Over time, the Board may approve a strategy for the management of risk concentrations, including the imposition of limits."

[1] The Risk Management Statement referred to a Risk Appetite Statement (RAS) required by the investment mandate direction, but pointed out that the RAS had not been made public.

CARMICHAEL-ABBOT POINT RAIL LINK: FINANCING ASSESSMENT ISSUES

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4.1 Rationale for NAIF Financing of NGBR Project

The former Minister for Resources and Northern Australia has articulated a rationale for concessionary NAIF financial support up to $1 billion for the NGBR project. He argued that government investment in large scale infrastructure could open up risky frontier areas, like the Galilee Basin, providing jobs and government revenue (Canavan, 2016; Ludlow, 2017). He claimed that this model had been applied to open up the Bowen Basin and every other Australian coalfield in the past. (Ludlow, 2017).

The only specific circumstances of government financial support for export coal activity outlined by the former Minister related to the Hunter Valley. He explained (Canavan, 2016):

"On the first day of spring in 1961, Robert Menzies (then Prime Minister) announced that the Commonwealth Government would provide the NSW Government £2.65 million ($73 million in today's dollars) to upgrade coal loading facilities in Newcastle. The investments would support the then fledgling coal trade with Japan.

The investment turned out to be a decision of great foresight and it was made against some scepticism. At the time, the CSIRO warned that Australia did not have enough coal to support an export trade.

Lucky for us that advice was ignored. Newcastle is now the biggest coal port in the world………

The Hunter Valley rail network remains in government hands, with the Australian Government leasing the network from the NSW Government 12 years ago. The Australian Government invested a further $150 million in the network. That network provides services to large multinational companies, for a fee, and the entire trade helps underpin our second biggest export, coal.

From here in North Queensland, and given the success of these previous investments, it's perplexing that some find the notion of investing once again in coal infrastructure as 'welfare'. ……….

The proposed Adani Carmichael coal mine in the Galilee Basin is a game changer for North Queensland because it is not just about this mine. It will be the first time that a new coal basin is opened in Australia for more than 40 years. If a rail line is built from the Galilee to Abbot Point it has the potential to spur another three mining ventures at least. The level of wealth that could be unlocked is comparable to that of the Hunter Valley or the Bowen Basin. That is why it must be a priority for a national government that is serious about developing our nation. There are risks for any first mover so while Adani may yet decide to take all those risks on itself, it may not. Given the wider benefits to the Australian economy, it makes sense for the Government to look at its request for a loan to help build the railway."

In reality, the approach to infrastructure financing when coal mining for export took off in the Bowen Basin was different to the one that the former Minister suggested had applied there and that he had been advocating for the proposed Carmichael Mine in the Galilee Basin. The Queensland Government required mining companies to lodge "security deposits" sufficient to cover the actual capital cost of economic infrastructure (including locomotives and other rolling stock in the case of railways). The money was used to provide the infrastructure which became the property of government. Security deposits were repaid with interest from receipts from contracted charges and usage. The magnitudes of periodic repayments were dependent on usage. No payments had to be made in respect of a period if a specific usage threshold for that period was not exceeded. If thresholds were not exceeded for several years, security deposits and interest were forfeited to the government.[2]

[2] For example, see the original agreement dated 28 January 1969 attached to the *Central Queensland Coal Associates Agreement Act 1968*.

The Queensland infrastructure financing model associated with opening up the Bowen Basin required mining companies to fully bear risks of providing economic infrastructure for export coal mines. The NAIF concessionary finance model advocated by the former Minister to help open up the Galilee Basin would shift in excess of 40 per cent of the risk to Australian taxpayers and beneficiaries of other government activities, without any direct compensation for risk bearing. Apparently, compensation is presumed to ensue in the form of "public benefit" from helping to finance the project.

Sensibly, the former Minister stated (Canavan, 2016):

"Any loan has to stack up for the Commonwealth and that is why the Government has appointed an independent, skills-based board to the NAIF. The NAIF was supported by the Parliament and we should let the independent board do its job."

To do its job, the NAIF board will need to assess nett economic benefits of the NGBR project, as well as "bankability" having regard to risk.

It is not clear how the NAIF will assess nett economic benefits of the project. It would be appropriate to commission a social benefit-cost analysis by a highly proficient practitioner. Such a study would test the former Minister's rationale for concessionary financing support for the NGBR project.

This analysis should take into account the opportunity cost of capital allocated to the NGBR project and risk associated with it, along with other costs (including adverse environmental impacts) to society, as well as social benefits. Those other costs should include crowding-out effects arising from the effect of very large shipments from Galilee Basin on thermal coal prices, and from the effect of revenue and foreign-sourced capital investment on the Australian dollar exchange rate. Coal price effects would adversely affect thermal coal activity in the Hunter Valley, Bowen Basin and Surat Basin. Exchange rate appreciation would adversely affect export and import-competing industries.

A SCBA would take into account benefits beyond those that Adani could capture, as required by NAIF's investment mandate direction. The former Minister's rationale for provision of a concessionary government loan to Adani presumes that such benefits are large.

To produce benefits beyond those able to be captured by the proponent, particularly benefits to other users (as required by the investment mandate), access to infrastructure would have to be priced on a basis that would provide cheaper services than could be achieved by building separate infrastructure or by negotiating access to alternative infrastructure. Potential Galilee Basin producers other than Adani might pay to access the NGBR link, build another rail link to a port, or enter into an arrangement with Aurizon to link with and access Aurizon's existing narrow gauge network that would allow coal to be shipped to terminals in ports at Abbot Point or Hay Point. Benefits would accrue to other users of the NGBR link to the extent that the price for access charged by Adani is less than the cheapest of the alternatives. These benefits would simply reflect the price difference, unless that difference triggered development of additional new mines. Nett benefits from additional mines in the Galilee Basin would be diminished by crowding effects mentioned above.

To trigger decisions to proceed with projects that would not otherwise be developed (leading to benefits in excess of differences in freight costs), it seems that the access price charged by Adani would have to be substantially (not just marginally) below the price implied by alternative arrangements. This seems unlikely. If the NGBR link is regulated, Adani would be able to charge a price up to full economic cost recovery. If NGBR is not regulated, Adani would seek to charge a higher price that would allow for the effect of coal production by other users of the NGBR link on coal prices attainable for Carmichael coal.

Presumably, a credit assessment undertaken by the Export Finance and Insurance Corporation for NAIF will be considered in the light of the NAIF's explanation of its high risk tolerance in its Risk Management Framework. Presumably, further explanation of the basis for the NAIF's high risk tolerance is provided in the Risk Management Statement (RAS) required by the investment mandate direction. However, it was not possible to review the RAS as it has not been made public.

The NAIF's high risk tolerance appears to derive from a presumption that projects financed by NAIF are expected to generate nett economic benefits that are large enough to compensate for high risk. The NAIF's high risk tolerance in respect of any project should be based on receipt of positive results an economically sound social benefit-cost analysis of that project, not on a presumption of sufficiently large nett benefits.

4.2 Credit or "Bankability" Assessment

Typically, credit or "bankability" assessments systematically identify sources of risk and uncertainty (referred to as risk hereafter), assess the extent of that risk, and specify mechanisms available to mitigate, transfer (shift) or compensate for identified risk. Then, decisions have to be made by potential lenders regarding the acceptability or otherwise of risk, what conditions could be specified and imposed to reduce risk, and the acceptability of residual risk.

In the case of a mining operation, and also a railway line and other infrastructure built for the sole purpose of supporting a mining operation, sources of risk include:

- geological risk – the quantity and quality of resources may differ from estimates
- mining risk – mining conditions and extraction costs may not be as anticipated
- processing risk – coal processing yield and/or costs may differ from expected outcomes
- design and construction risk – plant, equipment, and infrastructure costs, timing of commissioning, and performance may depart from anticipated outcomes
- natural disaster risk – costs of damage, delays, and other disruption from natural disasters such as cyclones, storms and floods
- commodity market risk – prices may differ from expectations because of unanticipated changes in market conditions, such as demand growth, supply growth, and preferred product specifications[3]
- exchange rate risk – prices of exported outputs and imported (or import competing) inputs may change because of exchange rate movements
- policy risk – regulatory and fiscal frameworks may change in the jurisdiction in which the mine and infrastructure are based or in jurisdictions that use the mine's products.

Geological, mining, processing, market, exchange rate, and policy risk affect marketable reserves (profitably recoverable and saleable material) and mine longevity, as well as periodical profits. Natural disaster risk affects periodical profits.

Subject experts are usually engaged to analyse and advise on the nature and extent of each type of risk, and how to mitigate that risk, if potential financiers do not have appropriate in-house expertise. Such analysis and advice by external or internal experts provides additional information regarding the likelihood of an adverse outcome. NAIF should adopt that convention.

Pre-conditions of lending that might be imposed by a prudent potential financier to reduce the likelihood or effects of adverse outcomes include:

- additional drilling in advance of provision of loan funds to raise the status of (degree of confidence in) resource and reserve estimates
- refinements to designs of mining, processing, and infrastructure facilities
- insurance contracts covering various adverse events
- long-term product sales contracts that specify quantities and prices (but thermal coal prices in international contracts are usually re-set annually, not fixed on a long-term basis in nominal or real terms) or other commodity price hedging arrangements
- exchange rate hedging
- an assessment demonstrating that the viability of the project is not dependent on establishment of other mines that would share the cost of major infrastructure facilities
- as security, the lender having full recourse to substantial assets with no or little encumbrance, other than assets of the project to be financed (NAIF may lend on a limited-recourse basis with charges over assets confined to project assets – known as project finance)
- assessment of likely compliance with specified debt servicing cover and security cover ratios.

It is not known which if any of the approaches outlined above might be adopted or eschewed by NAIF in assessing Adan's loan application and in conditioning an approval. Two key requirements of the

[3] Technological advances may affect demand growth by lowering the cost of substitutes and supply growth by lowering costs of coal extraction.

investment mandate direction provided to NAIF by the Minister at that time could pull the board of NAIF in opposite directions. The board could move away from normal banking due diligence practice to meet the requirements that it may provide a financing mechanism only if satisfied a project would not otherwise have received sufficient financing from other sources, and only if the public benefit test is passed. On the other hand, the board may want to adopt normal prudent credit assessment and loan structuring practices to comply with the requirement that it must be satisfied there is an expectation that either the Commonwealth will be sufficiently repaid to cover NAIF's administration cost and the Commonwealth's cost of borrowing or the investment can be refinanced. The NAIF may have great difficulty satisfying all requirements in the case of the NGBR project that would support the Carmichael Mine.

Market risk is a highly problematic issue to be addressed by NAIF in its consideration of Adani's loan application. It is critically important to the "bankability" of the Carmichael project and the rail component of it.

Even if a long-term contract that fixes real or nominal prices for Carmichael thermal coal could be agreed, contract prices are likely to be strongly influenced by prevailing views regarding the price outlook for thermal coal. Views of credible organisations and economic analysts regarding short-, medium-, and long-term outlooks for thermal coal prices are discussed in the next section.

THERMAL COAL PRICE OUTLOOK: VIEWS OF CREDIBLE ENTITIES 5

At present, there is considerable pessimism regarding the long-term outlook for prices of thermal coal in international markets. This is reflected in forecasts by credible Australian and international agencies.

5.1 Historical Background on Coal Market

The nineteenth century could be described as the century of coal. This commodity underpinned industrialisation in Europe and the United States. During that century coal gained a 90 per cent share of the global market for primary energy. In the twentieth century, coal's market share was eroded by other primary energy sources, particularly oil, but also gas, uranium and renewables. In 1964, oil became the dominant primary energy source and has retained that position. By 2000, coal's market share had fallen to a low of 23 per cent. From 2000, coal's share of the primary energy market made a comeback, reaching 30 per cent in 2015 (Hecking, 2016).

Over the 25 years to 2014, global coal use grew at an average rate of 2.5 per cent per year. Between 2000 and 2010, global coal demand grew at an average rate of 4.7 per cent, compared to average rates of growth of demand for oil and gas of 1.2 per cent and 2.8 per cent respectively (IEA, 2016).

The rapid growth of demand for coal in the first decade of the 2000s was attributable largely to economic growth in China, India and other rapidly developing Asian economies, particularly China. and resulting derived demand for coal (IEA, 2016; Hecking, 2016). Chinese coal demand tripled and Indian demand doubled between 2000 and 2013. The attraction of coal was that it was relatively cheap and abundant, and available domestically in many major user countries with only 17 per cent of coal production being traded internationally. China, the world's largest importer of coal imports less than 10 per cent of its annual coal demand, and India, which is the third largest importer of coal, imports less than 30 per cent of its coal demand each year (Hecking, 2016).

During the first decade of the twenty-first century, supply grew at a slower rate than rapidly growing demand, as a result of various types of lags in the supply response sequence. Consequently, thermal coal prices soared to ration scarce supply.

In January 2011, the Newcastle benchmark (6,300 kcal/kg GAR[4]) thermal coal coal spot price peaked around US$160 per tonne f.o.b. Newcastle (real 2017 US$). The average real price in January 2011 was about US$155 per tonne. At the end of June 2011, Newcastle benchmark thermal coal spot and contract prices still exceeded US$130 per tonne f.o.b. Newcastle (real 2017 US$). Thermal coal prices trended down for the next four and half years. In January 2016, prices were below US$50 per tonne.

The spot price for benchmark Australian prime hard coking (metallurgical) coal also peaked in January 2011 around US$365 per tonne f.o.b. The contract price for benchmark coking coal peaked around US$395 per tonne (real 2017 US$). Like thermal coal prices, metallurgical coal prices followed a marked downward trend until early 2016, when the benchmark spot price dropped to around US$100 per tonne.

In 2011, thermal and metallurgical coal markets transitioned from excess demand to excess supply. This occurred as demand growth slowed and supply surged. Much of the supply increase occurred several years after prices moved to relatively high levels, because of various lags in the supply response process. The emergence of substantial excess supply triggered a persistent price downtrend to transition the market to balance.

[4] GAR = gross as received. The specific energy value has not been adjusted for the latent heat of water vapour, which lowers effective calorific value in the boiler.

Global coal use stopped growing in 2014 and turned down in 2015. The change in the trend in demand for thermal coal had various causes. First, economic growth was slowing in China and India. Second, the Chinese Government was working to transition the economy from high dependence on exports of industrial goods and investment activity to greater shares of services and consumption. Third, the Chinese Government sought to reduce air pollution. Fourth, growth in high income countries faltered, and climate change policies reduced coal's share in energy use. Fifth, in the United States, discovery and development of large shale gas reserves led to low gas prices that induced an increase in use of gas at the expense of coal in electricity generation at the expense of coal (IEA, 2016; Office of Chief Economist, DIIS, 2016, 2017a,b).

The substantial fall in thermal and metallurgical coal prices that occurred between mid-2011 and early 2016, caused considerable pain in the coal mining sector globally. Early in 2016, companies producing nearly half of United States' coal output were under bankruptcy protection, and 80 per cent of coal mining enterprises in China were incurring losses (IEA, 2016).

In the second half of 2016, the spot thermal coal benchmark price recovered strongly from around US$50 per tonne to reach a short-lived peak of around US$110 per tonne in the middle if the fourth quarter of 2016. The spot price declined late in 2016 and early in 2017. It was around US$84 per tonne at the end of February 2017, just under US$75 per tonne on 31 May 2017. It recovered to around US$78.50 per tonne late in June 2017. Reflecting the sharp spike in thermal coal spot prices in the second half of 2016, and spot prices in the first quarter of 2017 that were much higher than in the corresponding quarter of 2016, the Office of the Chief Economist, Department of Industry Innovation and Science (2017b) reported an average export contract price for the year form from 1 April 2017 to 31 March 2018 (Japanese Fiscal Year 2017-2018) of US$84 per tonne f.o.b. Newcastle, compared to US$63 (real 2017 terms) for the preceding year.[5]

The benchmark hard coking coal spot price also soared in the second half of 2016. It peaked around US$311 per tonne in mid-November. In early December 2016, the Japanese contract price for the March quarter of 2017 was settled at US$285 per tonne. Spot prices declined substantially in the first quarter of 2017, but the trend was halted and prices rallied strongly because of disruption to Queensland shipments caused by the destructive effects of Cyclone Debbie. Following the restoration of normal shipments, spot prices trended down.

The coal price revival in the second half of 2016 was attributed mainly to cuts in production capacity in China that commenced in April 2016, with a lesser contribution from a spike in summer demand and some supply disruptions elsewhere. The drop in prices from mid-November was attributed to the Chinese Government's easing of the capacity-cut policy, resolution of export supply disruptions, and seasonal change (Reserve Bank of Australia, 2017a; Office of Chief Economist, DIIS, 2016, 2017a,b; IEA, 2016).

As a result of the sharp spot price increase in the second half of 2016 and despite the subsequent price decline, the Office (2016) estimated an increase of 3.7 per cent in Australian thermal coal exports in the year to 30 June 2017. The Reserve Bank of Australia (2017a) observed that while changes in spot prices since mid-2016 had improved the profitability of Australian coal exporters, its research indicated that prices would need to remain elevated for some time to induce any noticeable increase in Australian production. In July 2017, the Office (2017b) downgraded its forecast of an increase in production to just 0.5 per cent.

5.2 Short-Term Thermal Coal Market Outlook

In early March 2017, the Chinese National Development and Reform Commission advised that China intended to cut coal mining capacity by 150 million tonnes per year in 2017. However, the proviso was that "the coal price remains in a reasonable range". It did not define a "reasonable range". It could be assumed that current spot prices would be at the top of the range, because it is obvious that the Chinese Government considered the price spike that occurred in late 2016 was undesirable. Also, it is reasonable to assume that prices that prevailed in early 2016 before China commenced its capacity reduction programme would be well below the bottom of the range, as such prices signalled

[5] The average contract prices reported by the Office of the Chief Economist, DIIS (2017b) applied to 6700 kcal/kg thermal coal on a gross air dried basis.

the existence of excess supply of coal and meant that many Chinese coal mines incurred losses. The Reserve Bank of Australia (2017a) observed that it is not clear whether or not the Chinese Government would continue to force policies that have contributed to lower Chinese production of coal, particularly given the elevation of coal prices caused by those policies.

The IMF's Research Department Commodities Unit (2017a, p. 2) argued that the revival of thermal coal prices in the second half of 2016 would not persist. It expected thermal coal prices "to decline sharply within a year". Subsequent forecasts by the IMF's Research Department Commodities Unit (2017d) indicated Newcastle benchmark thermal coal prices in nominal terms would decline from an average of US$87.91 in the first quarter of 2017 to US$77.42 per tonne in the fourth quarter of 2017 and then to US$69.89 per tonne in the fourth quarter of 2018.

The World Bank Group (2017a,b) expected thermal coal prices would fall in nominal and real terms in 2017-2019. It forecast an average price of US$70 per tonne f.o.b. Newcastle in 2017, and nominal prices of US$60 per tonne in 2018, and US$55 per tonne in 2019.

The Office of the Chief Economist, DIIS (the Office) (2017b) reported that thermal coal export contract prices increased to an average of US$84 per tonne, in the period 1 April 2017 to 31 March 2018, in response to the large spike in spot prices that occurred in the second half of 2016. The contract price was expected to fall to US$70 per tonne (real 2017 terms) in the 2018-19 Japanese fiscal year and to US$67 (real 2017 terms) in 2019-20. Spot prices were expected to average US$77 per tonne in calendar year 2017, compared to an average of US$67 and a peak of US$110 in 2016 (2017 real terms). Further decline in the spot price was expected in 2018 and 2019, with prices forecast to average US$69 per tonne f.o.b. Newcastle and US$66, respectively, in real 2017 terms. The Office based these forecast price declines on an expectation that import demand from China would decline as it moved to a more diversified energy mix, Indian import growth would be constrained because of slowing growth in coal-fired power generation and a government policy of reducing reliance on imported thermal coal (Indian imports have been declining since 2015), and South Korean plans to curb coal-fired electricity generation to reduce air pollution.

The Office (2017b) forecast that global import demand for thermal coal would decline by 2.4 per cent to one billion tonnes in 2017, followed by a further decline of 2.1 per cent to 990 million tonnes in 2018, and a smaller decline of 0.4 per cent to 986 million tonnes in 2019. It explained that these declines were expected to be driven by lower import demand from China, India and South Korea.

5.3 Medium-Term Thermal Coal Market Outlook

The Office of the Chief Economist, DIIS (2017a,b) forecast that the benchmark Newcastle thermal coal spot price would fall from an average of US$77 per tonne f.o.b. in 2017 to an average of US$62 per tonne in 2020, and US$59 per tonne in 2022 in real 2017 terms. Contract prices were expected to be US$84, US$62, and US$60 per tonne, f.o.b., in 2017, 2020, and 2022, respectively, in real 2017 terms.

IMF's Research Department Commodities Unit (2017d) forecast that Newcastle benchmark thermal coal prices would fall during 2017, dropping from an actual average of US$87.91 in the first quarter to a forecast average of US$77.42 per tonne in the fourth quarter and US$82 per tonne over the year. Further declines in nominal prices (and therefore, real prices) were forecast out to 2022. The IMF's Commodities Unit forecast an average nominal price of US$72.39 in 2018, US$69.19 in 2019, US$67.90 in 2020, US$67.82 in 2021 and US$67.80 in 2022. In real 2017 terms, the indicated average price would be about US$63.90 in 2020, and US$61.30 per tonne in 2022.[6]

The World Bank Group (2017a, b) anticipated that the Newcastle benchmark thermal coal price would fall in real and nominal terms from 2017 to 2019, and rise slowly in nominal terms thereafter, while falling in real terms. It expected an average price of US$70 per tonne f.o.b. Newcastle in 2017, a nominal average price of US$55.40 in 2020, and a nominal average price of US$56.30 in 2022. This

[6] In this sub-section, nominal price forecasts have been deflated to real 2017 terms at a rate of 2 per cent per year. This is approximately equivalent to the World Bank's (2017a) use of an estimated manufacturers unit value (MUV) index based on US$ prices of manufactured goods exported from 15 countries: China, Japan, India, South Korea, Thailand, Germany, France, United Kingdom, Italy, Spain, United States, Canada, Mexico, Brazil and South Africa.

suggests an average price in 2020 of about US$52 per tonne, and in 2022 of around US$51 per tonne in real 2017 terms.

Bullen, Kouparatsas, and Krolikowski (2014) of The Australian Treasury forecast that Newcastle benchmark export thermal coal prices would decline from 2014 to 2017 to a low of around US$60 per tonne, before recovering to around US$67.50 per tonne in 2021 (2017 terms). The forecasts were generated by Treasury's global thermal coal model.

Bullen, Kouparatsas, and Krolikowski (2014) did not anticipate the Chinese capacity cuts that commenced in April 2016, their effect on spot prices in the second half of 2016, and the possibility of a flow-on to contract prices from April 2017. However, their price forecast of around US$60 per tonne in 2017 was close to the actual contract price of US$62 per tonne.

The International Energy Agency (IEA) (2016) argued that capacity cuts were likely to continue over the next five years in the context of excess supply, and demand growth is expected to be much lower than in the 25 years to 2014 and may be negative. Capacity cuts could be market-driven, politically administered (as in China), and result from depletion of deposits. According to the IEA, China intended to cut up to 1,000 million tonnes per annum of coal mining capacity during the period to 2020.

The IEA expected that the combination of capacity reductions (in various ways) and some growth of global demand would eliminate the excess supply disequilibrium by the early 2020s. Any growth of global demand for coal, following declining demand in 2014 and 2105, was anticipated to arise from economic growth and derived coal demand in India and south-east Asia that would more than offset declining coal demand in China, the European Union and the United States.

The IEA considered that the forecast change in market circumstances would lead to a recovery of prices by the early 2020s. Early 2020s contract prices for thermal coal in the range of US$70 to 75 per tonne f.o.b. Newcastle in 2017 real terms were expected, in the absence of tougher new climate change mitigation initiatives (like those assumed in the IEA's 450 scenario, rather than those already foreshadowed and included in the IEA's New Policies scenario – both outlined in the next sub-section). The IEA argued that price recovery would be stronger to the extent that demand growth, rather than capacity cuts eliminated excess supply.

The IEA commented that price recovery would restore the profitability of some mines previously incurring losses. Cost cutting since 2012, along with lower input prices in the context of lower demand for inputs, had also contributed to improved profitability.

However, the IEA had doubts that the capacity cut target of 1,000 million tonnes per annum in China would be achieved. Also, it argued that whether the Chinese capacity cuts and capacity reductions elsewhere would be sufficient to move the market from excess supply to balance by the early 2020s was an open question. In respect of this issue, the IEA noted that there was still a substantial amount of new thermal coal mining capacity in the investment pipeline.

The IEA's doubts appeared to be shared by other reputable institutions. The IEA's view on prices in the medium term, without adjustments for reservations it expressed about the realisation of capacity cuts, is more optimistic than the views of the World Bank Group (2017a,b), the IMF (2017d), and Bullen, Kouparatsas, and Krolikowski (2014) of the Australian Treasury.

5.4 Long-Term Thermal Coal Market Outlook

5.4.1 Views of Credible Agencies

Forecasts generated by Bullen, Kouparatsas, and Krolikowski (2014) of The Australian Treasury using The Treasury's global thermal coal model indicated that thermal coal prices would settle in a range of US$A85 to $A87.50 per tonne f.o.b. (real 2017 prices) from 2021 to 2030. The exchange rates attaching to these Australian dollar prices were not specified. Applying an exchange rate indicative of that applying in the first quarter of 2017, the forecast US$ price range for Newcastle benchmark coal from 2022 out to 2030 would be in the declining range US$65 per tonne to US$63.50 per tonne.

The World Bank Group (2017b) anticipated that the Newcastle benchmark thermal coal price would fall in nominal terms out to 2019 and in real terms from 2017 to 2030. It forecast an average nominal price of US$55 per tonne f.o.b. Newcastle in 2019, a nominal average price of US$56.30 in 2022, and US$60 in 2030. In real 2017 terms, the indicated average price would be about US$51 per tonne in 2022 and US$46 per tonne in 2030.

The IMF's Research Department Commodities Unit (2017d) provided forecasts of Newcastle benchmark thermal coal prices only out to 2022. It predicted an average nominal price of US$67.80 in 2022. In real 2017 terms, the indicated average price would be about US$61.30 per tonne in 2022.

The IEA's (2016) analysis of the long-term outlook for thermal coal involved three scenarios, each of which started with a medium-term (circa 5 years) outlook of elimination of excess supply by the early 2020s, as outlined in the previous sub-section. The three long-term scenarios produced divergent outlooks that reflected differences between assumptions made to create each scenario.

The IEA's three scenarios were:

– *New Policies*, a "central" scenario that incorporates all government policies currently in place, and targets and intentions already announced, even if they had not yet been fully implemented

– *Current Policies*, a "high" scenario that is based on the assumption that existing policy measures are maintained without additions and deletions

– *450*, a "low" scenario that reflects implementation of policy measures considered to be consistent with a 50 per cent chance of limiting the global increase in temperature to 2 degrees Celsius.

The process of elimination of excess capacity by the early 2020s that was discussed by the IEA differed between the IEA's three scenarios. The extent of capacity cuts is largest in the 450 scenario, and least in the Current Policies scenario. Demand growth is largest in the Current Policies Scenario and least (significant demand decline) in the 450 scenario. Reflecting these differences, price recovery in the medium term is weakest in the 450 scenario.

The thermal coal use and price trajectories associated with the IEA's three scenarios diverge from 2020. The gap continues to widen out to the end of the forecast period, 2040.

Under the Current Policies scenario, (thermal and metallurgical) coal use globally was expected to grow at a rate of 1.2 per cent per year to 2040 (compared to 2.4 per cent per year over the 25 years to 2014), exceeding 6.7 billion tonnes per year in 2030 and 7.7 billion tonnes per year in 2040. This growth was expected to be concentrated in developing Asian countries. Thermal coal real 2017 prices were expected to approach US$78 per tonne by 2022, US$90 per tonne by 2030, and US$100 per tonne by 2040.

Under the New Policies scenario, coal use globally was expected to grow at a rate of 0.2 per cent per year to 2040, reaching about 5.8 billion tonnes per year in 2030 and 6 billion tonnes in 2040. Again, this growth was expected to be concentrated in developing Asian countries. Thermal coal real prices were forecast to be around US$73 per tonne in 2022, US$80 per tonne in 2030, and US$85 by 2040.

Under the 450 scenario, global coal use was predicted to drop at a rate of 2.6 per cent per year, down to around 3.8 billion tonnes per year in 2030, and 2.9 billion tonnes per year in 2040. In this scenario, thermal coal real prices would plateau around US$65 per tonne in the early 2020s, and then decline to around US$60 per tonne in 2030, and less than US$55 per tonne by 2040 (real 2017 price terms).

The IEA (2016) provided significantly lower forecasts under all three scenarios in the *World Energy Outlook 2016* than in its *World Energy Outlook 2015*, a year earlier. Nevertheless, the IEA remains more optimistic about the long-term price outlook for thermal coal than other high profile official agencies that have published price outlooks.

The IEA's (2016) worst case, the 450 scenario, provided a significantly more optimistic thermal coal price outlook than the World Bank Group's forecast price trajectory, and a slightly less optimistic view than the 2014 Australian Treasury forecast. The IEA's central scenario, New Policies, is much more optimistic than the long-term price outlooks offered by the World Bank and the Australian Treasury.

IMF's Research Department Commodities Unit (2016) flagged the possibility of stranded thermal coal assets, including "stranded reserves", in the long term. It pointed out that this could occur in the absence of "proper carbon capture and storage" for electricity generation and steel-making activities. The time horizon of stranding of assets was said to be uncertain because it was dependent on the uncertain timing of the transition from fossil fuels to renewable sources of energy ("the energy transition"). It was noted that history indicated that "energy transitions" take considerable time to complete. Nevertheless, the IMF's Research Department Commodities Unit (2016, p. 50) also observed:

"History may not repeat itself in that regard, however, in that the technological forces unleashed by the anticipated public and private responses to climate change seem much more potent than the factors driving earlier transitions and may lead to a relatively swifter transition this time, notwithstanding the potential delay implied by the current low-for-long fossil fuel price environment. Considering the industry's carbon emissions intensity, coal-related assets are more exposed to the risk of becoming stranded than are oil and natural gas assets."

For stranding of coal assets to occur, prices would have to fall to a level that removes sufficient coal from the proved and probable reserves category to cause cessation of production, or reduction of production below the capacity of extraction (mining and processing) and transport facilities, or reduction of the life of a mine below the potential commercially productive life of extraction and transport assets. Removal of coal from reserves through price changes that persist should be regarded as elimination of reserves, not stranding of reserves.

5.4.2 Economic Perspectives on Long-Term Future of Coal and Coal Prices

The future of fossil fuels has been attracting increasing interest in the mainstream economics literature.[7] The relevant literature has provided useful insights regarding long-term thermal coal prices.

An important insight is that there are good reasons to be pessimistic about the long-term price of coal even if governments of major coal-consuming countries do not act to strengthen substantially policies to mitigate greenhouse gas and other undesirable emissions from use of coal. This insight casts doubt on the optimism of IEA's (2016) long-term coal price forecasts under the Current Policies and New Policies scenarios.

Energy economics specialists Covert, Greenstone and Knittel (2016) of University of Chicago and MIT explained that coal prices were likely to be constrained by reported coal reserves (commercially recoverable at current or expected prices) large enough to supply current quantity demanded at current prices for more than 100 years. While the reserves-to-production ratio had fallen substantially for more than a decade to 2008, it had subsequently stabilised and risen slightly. The reversal of a downtrend in the reserves-to-production ratio had occurred despite substantial reduction of prices from mid-2011 until early 2016.

Reserves to production ratios for oil and gas grew steadily during the 30 years to 2010. Reserves are currently sufficient to supply currently production for around 50 years of production of each of these commodities (Covert, Greenstone, Knittel, 2016).

While depletion tends to raise marginal costs of extraction in individual operations, this effect has been offset by rapid improvements to exploration and production technologies and techniques that have facilitated additions to reserves. This phenomenon has been apparent across the three fossil fuels: coal, oil and gas. The abundance of each helps constrain prices of other fossil fuels.

Technological progress has also been rapid for production of electricity from renewables. This is likely to continue. It will lead to substitution of renewables for fossil fuels, constraining prices of fossil fuels.

Summing up, fossil fuel abundance, technological progress, and substitutability can be expected to combine to constrain thermal coal prices in the long-term. Moreover, predictions of declining prices might induce early production to take advantage of higher prices in the short-term, causing prices to fall. So, these predictions may become a self-fulfilling prophesy (Helm, 2016).

Natural resource and infrastructure economics specialist Dieter Helm of Oxford University observed in an analysis of the future of fossil fuels (Helm, 2016, pp. 203-204):

"The end of fossil fuels is not about to arrive, and will not be caused by running out of any of them. The quantities are sufficient to fry the planet several times over, and technological progress in the extraction

[7] For example, see Helm (2016), Covert, Greenstone, and Knittel (2016), Helm (2016), Collier, Venables (2014).

of fossil fuels has recently been at least as fast as for renewables. We live in an age of fossil fuel abundance.

We also live in a world where fossil fuel prices have fallen, and where the common assumption that prices will bounce back, and that the cycle of fossil fuel prices will not only reassert itself but also continue on a rising trend, may be seriously misguided."

Low coal prices could also persist in the long-term if use of coal is impeded or the cost of its use is raised through government regulations designed to reduce emissions (including regulations relating to selection of technologies), or by other government action to apply taxes or prices to greenhouse gas emissions or otherwise tax coal use. This was recognised in the IEA's (2016) coal price forecasts. The consequences of fossil fuel abundance, substitutability, and technological advances were not.

CONCLUDING REMARKS 6

There are several reasons for questioning the appropriateness of a Commonwealth Government loan of the order of $1 billion through the NAIF for the proposed Carmichael-Abbot Point rail link.

a) The task of securing debt and equity finance for a $21.7 billion project comprising thermal coal mines and supporting infrastructure, including a new 388-km standard gauge rail link and a new coal export terminal, would be very demanding at any time. It would be particularly difficult in the context of the current widespread perception of a negative thermal coal market outlook.

b) It is understood that Adani has not yet secured sufficient funding for the project to proceed, and it considers that obtaining a loan from the NAIF as critically important. This may be related to the size of the financing requirement and the profitability of the project at current prices and at prices forecast by credible entities. It is not possible to express a considered view on profitability without access to detailed information about the project's cost structure over time.

c) The NAIF by design is a provider of concessionary financial support only to entities that would not be able to obtain sufficient allow projects to proceed. Both the failure to obtain sufficient financial support from commercial sources, and provision of concessional terms mean provision of a loan or other financial mechanism to Adani for the rail project must be regarded as a high risk financing arrangement for the financier. NAIF's Risk Management Framework has stated that the NAIF has a high financing risk tolerance, but they will be imposing the high risk on Australian taxpayers.

d) It is not clear how the NAIF could meet the direction from government that there be an expectation of full repayment of the loan with interest, while providing support only if commercial financiers do not provide sufficient finance for the project to proceed. It seems that the expectation could not be high if sufficient private sector finance is not forthcoming.

e) The economic rationale for the proposed NAIF loan is highly simplistic and has not been substantiated by detailed economic assessment. The claim that all other coal basins in Australia have been opened up by government investment in infrastructure is not correct. In the Bowen Basin, mining companies bore the full cost and risk of providing rail and port infrastructure. In addition, a proper economic assessment of government financial assistance for construction of the proposed Carmichael-Abbot Point rail line would have to take into account, among other things, the risk-adjusted opportunity cost of the capital, the likelihood and magnitude of genuine induced investment in the Galilee Basin and benefits arising therefrom, pricing of access by other users, and crowding-out effects in the thermal coal mining sector, and other sectors.

f) There are sound reasons to be pessimistic about thermal coal prices in short-, medium- and long-term time frames. This pessimism seems to be justified, even in the absence of intensification of action to reduce greenhouse gas emissions in major coal-using economies. In the context of much stronger global action to mitigate climate change, the thermal coal price outlook would be bleak indeed

g) In the context of widely-held pessimism regarding the outlook for thermal coal prices, any economic surpluses (revenues less full costs including a reasonable return to investment) from opening up the Galilee Basin would be small, at best. Consequently, nett economic benefits would be small, at best, casting doubt on a loan from NAIF for the rail link being justifiable on economic grounds.

h) Similarly, widely-held pessimism regarding the outlook for thermal coal prices means that potential commercial lenders to Adani for the Carmichael project would reasonably be doubting that loans would be fully repaid with interest. NAIF should be even more concerned about recovering taxpayers money with interest, particularly as NAIF would probably rank behind other lenders.

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