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FROM THE OFFICE OF THE
CHIEF EXECUTIVE OFFICER

Ms Peggy Danaee,
Secretary, Standing Committee on the Environment and Energy
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Dear Ms Danaee,

Re: Inquiry into Modernising the Grid - Response to Questions on notice

David Swift and I enjoyed our opportunity to meet with the Committee on Friday 26 May and are happy to support the Committee's important work on this matter.

At the hearing, we were asked to provide additional information on six occasions. Those areas and our response are provided below.

- *How does locational congestion pricing work in the United States and Europe?*

Locational pricing was adopted by many of the United States and European wholesale markets to price out the value of the last increment of electric power used to meet demand at a location on the transmission system. The wholesale electricity price at each time (e.g. 30 minutes or 5 minutes) and each location (e.g. a node in a network) is set to mirror the physical flow of power and thus the cost of supplying an incremental change in demand at that location. Generators and dispatchable load receive a price that reflects the value of their supply at their location. This produces efficient signals and minimises the cost of managing network limitations while signalling where new generator and demand-side investment can offset congestion, reducing the need for uneconomic transmission investment.

When the network has no physical constraints, the price is the same everywhere. Network congestion can reduce the ability of low cost suppliers to serve the market while requiring more expensive supply in other locations to serve demand there. Locational congestion pricing reflects the difference in price between locations as a result of network congestion.

A distinctive feature of the US model is that congestion is seen as a property of the entire network, and congestion prices are defined between any two nodes in the network, effectively measuring the impact of all congested transmission paths between those nodes. This approach is required due to the vast number of nodes – PJM for example, determines prices at over 9000 load nodes and over 2000 generator nodes.

The standard approach in the US is that a day-ahead market is run to determine a feasible and economically efficient network schedule across time given bids and offers at different nodes of the network. Differences in prices between nodes at a given time

measure the cost of congestion between locations. US markets typically recover the cost of losses through separate charges so all price differences are due to congestion.

Congestion revenues collected by the market are used by default to off-set network investment costs, though do not typically fully fund them. The standard approach is to auction Financial Transmission Rights (FTRs) between two nodes. An FTR returns the congestion rent on a fixed quantity to the holder. They are auctioned with the aim of keeping the quantity sold within the capability of the network. The revenue from parties purchasing FTRs goes to offset transmission use of system charges. The FTR provides a hedge against price variations (or "basis risk") between locations, allowing energy contracts to be referenced to a common location.

Equity concerns for smaller customers (usually residential customers) are often addressed by settling them at a load weighed average price – this means they all pay the same price but enough revenue is generated to settle the energy market and FTRs.

It must be stressed that the energy market represents only one component of the US market. In most markets it is complimented with a capacity pricing model to incentivise new investment as well as other services necessary to secure the grid.

- *What is the process for generator retirement (i.e. notice period, reliability/security analysis, at-cost supply contract if required) in the United States?*

The specific process for managing generator retirement varies by market in the US though the generic approach is similar.

The minimum notification period varies by market, for example New York ISO has a 365 day notification period, the Midcontinent Independent System Operator (MISO) requires 26 weeks notification, while PJM and California require 90 days notification – though PJM requires a longer 2 year notification for facilities providing black start capability.

Information required from generators includes information on the anticipated closure date, whether it is permanent or not (e.g. if mothballed), and in some cases include the requirement to provide information on the expected cost of keeping the unit operational beyond that date.

During the notification period the market operator works with transmission network operators to determine the impact of the closure. While the primary focus is generally on impact on power system reliability, broader assessments can also be made, e.g. whether the closure would require additional market power mitigation measures to be imposed in the market.

Where reliability issue are found there is normally a process conducted as to what options would address the issue, such as new transmission investment or contracting replacement services, like black start, from remaining resources. The possibility of keeping the generator open under a contractual arrangement is also considered.

If is identified that it is necessary to keep the generator operating until the situation allows it to close then the market operator will seek to develop a contract with it. The contract is generally constructed to compensate the generator at its going forward costs until an alternative can be developed. The contract is typically filed with and has to be approved by the Federal Energy Regulatory Commission (FERC), the rough equivalent of the AEMC and AER.



It should also be noted that long term planning by market operators includes some allowance for expected closure dates of generators. While these are estimates they complement the information provided by these near term processes.

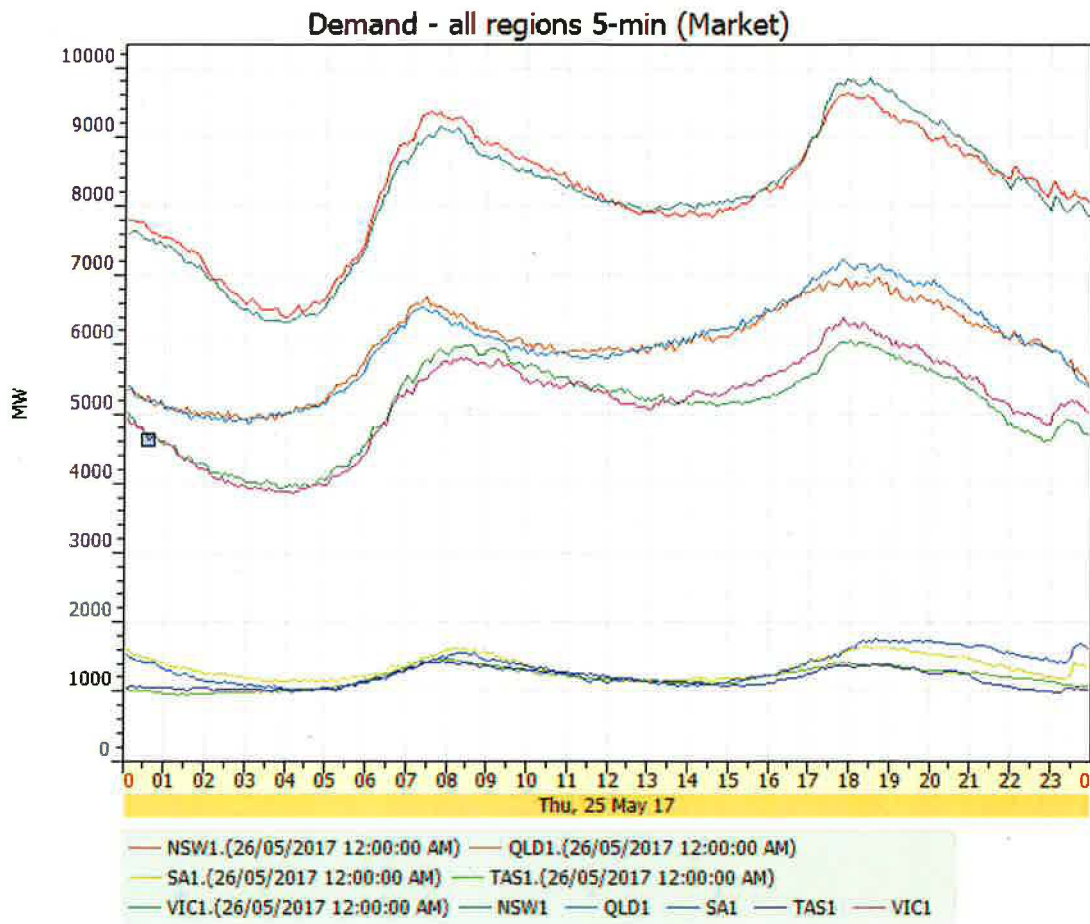
It is important to note that a generator may also be obligated remain in service in US markets for other reasons. For example a generator may have multiple year commitments under a capacity market which may preclude it from retiring under these process until those obligations are complete.

- *What was the cause of the reduction in demand (of approximately 1000 MW) that occurred at 7:30 am on 26/5?*

We have reviewed the demand profile for all regions of the NEM demands on 26/5/17 and have found nothing unusual.

Below is a chart of the operational demand in each region on that day, overlaid on the previous day's demand. The graph shows the five minute demand for each case and each demand trace follows a pattern now common across the NEM. At 07.30 AM, the operational demand (or net demand on the grid) peaked in New South Wales, Queensland and Tasmania. The operational demand then gradually declined through the morning and early afternoon as growth in customer demand was offset by rooftop solar generation. Later in the afternoon there was a second peak at around 6:00 PM as embedded generation declined while demand remained high into the evening. Victoria and South Australia show a similar shape but with slightly different timings.

If the question related to a different day or time, we would be happy to investigate that.

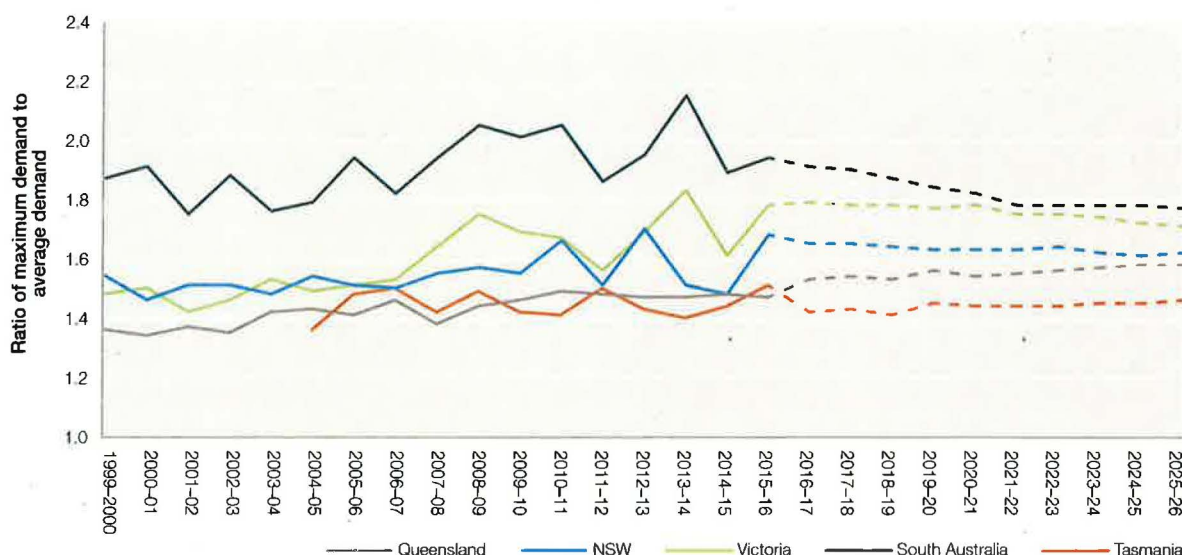


- *What is the capacity factor in the Australian electricity system?*

The AER "State of the Energy Market" from May 2017 provides the following graph of the ratio of the maximum grid demand to average grid demand. This is mathematically the inverse of the capacity factor and one way to visualise the 'peakiness' of the demand. The ratio varies significantly year to year as the maximum demand in any year is very sensitive to the weather and the day of the week and week of the year on which the most severe weather occurred. The ratio varies by region based on the customer mix and nature of demand. Typically, where there is a higher proportion of industrial load, and hence 24 hour usage, the capacity factor is higher. A high proportion of air-conditioner load generally leads to a lower capacity factor. The capacity factor has reduced slowly over the past 20 years, continuing a long term trend.

Figure 1.5

Ratio of maximum grid demand to average grid demand



The lowest (worst) capacity factor in the NEM is then in South Australia where a ratio of around 2.0 converts to a capacity factor of 50%. At the other end of the scale, a ratio of around 1.5 in Queensland and Tasmania converts to a capacity factor of 67%.

- *How does the affordability measure for electricity work in New York?*

New York has moved away from a retail competition model to one where regulated utilities are incentivised to reward customers for managing their consumption, though competition can still occur in provision of low emission energy. New York has a goal of 50% of the state's electricity needs to be supplied by renewable energy by 2030.

Lower consumption decreases the base across which network costs must be recovered, and combined with costs of transiting to a lower emission system, this created concern about the increasing proportion of household budget attributable to energy.

The New York Public Service Commission announced the Energy Affordability Policy in May 2016 with the aim of limiting energy costs (gas and electricity) to 6% of household income for low-income customers in the state of New York. The 6% target represents the high end of average energy costs for middle income New Yorkers. The goal is achieved in part by improving overall efficiency especially through the use of distributed energy resources to increase productivity. The cost to low income customers is further reduced through monthly discounts provided by the regulated utilities to their customers.

A total of \$US130 million of pre-existing subsidies for low income customers were brought into the Energy Affordability Policy with the new policy having a total annual budget \$US 248 million. This allowed the number of customers provided discounts to be increased from 1.1 million to approximately 1.65 million households. The subsidies are associated with existing classifications of customers and vary with these classifications. The State's objective is to eventually cap all 2.3 million of New York's low-income households "at no more than 2 percent of utility revenues, a level found to be sufficient

to meet the 6 percent energy burden goal for most utilities while balancing rate impacts on other classes of customers.”

The government is also establishing a range of schemes to improve opportunities for low-income people to reduce energy usage through energy efficiency measures including housing improvements and by supporting customers’ access to investment in renewable energy.

In addition to the specific low income discount, the New York government also supports industry in New York by providing them access to low cost State owned hydro power at preferential prices and allowing them to take advantage of State supported energy efficiency funding. Further, all utilities and the wholesale market operator in NY will help customers reduce their monthly bill by compensating them for participating in the demand response programs. The State measures industrial energy prices against national averages with the soft objective of being in lowest decile of these costs.

- *What are the inertia requirements in South Australia and how do these requirements translate to a maximum share of wind generation?*

AEMO is currently determining the minimum inertia requirements for the NEM as a whole and for each region. We expect to have a Rules obligation to do so in the coming months but at this stage we do not have specific requirements. We do, however, limit the rate of change of frequency in South Australia to 1Hz per second following a credible contingency and to 3 Hz per second following the non-credible loss of the Heywood interconnector. This is implemented through constraint equations which limit the transfers on the interconnector depending upon the level of inertia online in South Australia at the time. To maintain a minimum level of system strength in South Australia at all times, we currently also require two synchronous units to be online in SA at all times. This effectively ensures a minimum level of inertia – for example, one Torrens Island B unit plus one Torrens Island A unit would provide around 1,700 MWsecs of inertia.

AEMO is continuing detailed modelling of the performance of the grid and the behavior of generating plant on the grid. Rule changes currently in progress will provide a clearer framework for the determination of minimum inertia levels which will depend upon a range of factors including:

- The frequency operating standards applicable;
- The size and nature of the contingent risks the system is protected from; and
- The availability and speed of frequency control ancillary services.

All of these aspects are currently under review. There is a secondary impact on the requirement depending upon the generation mix operating at the time.

We should note that the national requirement for inertia with all lines in service is easily met and unlikely to become an issue in the near future.

In our evidence, we referred to the unusually high level of interest in new, mostly renewable, generation currently considering connecting to the grid. There have been many formal and informal requests for information on connection requirements and a number of these have resulted in formal connection inquiries and applications. AEMO is currently managing 180 active connection projects across the NEM (as at 16 June 2017). Anecdotally we understand



there are substantially more projects being developed in the NEM for which AEMO does not have visibility. The number of active connection projects being managed today is substantially more than AEMO has dealt with over the past 2 years.

AEMO would be happy to provide further information to the Committee on these or other matters.

Yours sincerely

Audrey Zibelman
Chief Executive Officer