4 September 2014

Mr John Pierce
Commissioner
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Submitted online: www.aemc.gov.au

Dear Mr Pierce

EPR0039 – First Interim Report – Optional Firm Access, Design and Testing

Origin Energy (Origin) appreciates the opportunity to provide comments to the Australian Energy Markets Commission (AEMC or Commission) First Interim Report on Optional Firm Access (OFA), Design and Testing. Origin understands the objective of the OFA model is to co-optimise generation and transmission investment to minimise the total system costs borne by consumers.

Origin does not consider, as a large generator, the OFA model will improve financial certainty for generators as intended or that economic benefits can accrue to consumers through changing the commercial arrangements between generators and network service providers as envisaged under the OFA model.

Current planning arrangements allow for the co-optimisation of generation and transmission investment through an assessment of commercially and technically feasible options under the Regulatory Investment Test for Transmission (RIT-T), combined with generator assessment of the impact of network congestion when making locational decisions.

AEMO analysis has indicated that benefits from access settlement under the OFA model are not clearly identifiable:

> *AEMO has reviewed recent events of non-cost reflective offers in order to test this hypothesis. In each of these events, generator behaviours were also affected by a number of market design and structural issues which are outside of the scope access settlement. It will be difficult to identify the incremental benefits that arise from access settlement alone.*[1]

AEMO's analysis also suggests there will be material wealth transfer between participants if implemented.[2]

The proposed OFA model, if implemented, would impose significant complexity to the National Electricity Market (NEM) making assessment of investment options more difficult and prone to error. The complexity is derived from linking access capacity in settlement and treatment of auxiliary loads and loss factors. Discrepancy between 5 minute dispatch and 30 minute trading intervals creates additional complexity for calculating marginal constraint values as flowgate prices from a dispatch interval into a trading interval.

---

[1] AEMO 2014, 'Optional Firm Access AEMO First Interim Report,' July 2014, Melbourne p. 3.
[2] Ibid. p. 8.

Origin Energy Limited ABN 30 000 051 696 • Level 45, Australia Square, 264-278 George Street, Sydney NSW 2000
GPO Box 5376, Sydney NSW 2001 • Telephone (02) 8345 5000 • Facsimile (02) 9252 9244 • www.originenergy.com.au

The OFA model could, however, be detrimental to the generation and transmission planning process. The complexity, cost and financial uncertainty for generators in assessing potential incremental benefits from a network augmentation in the future would make investment decisions difficult. These problems could be exacerbated by commercial arrangements creating significant inefficiencies through information and power asymmetries between generators and TNSPs with the efficiency of an investment undiscernible due to a reduction in transparency through the planning process and removal of AEMO as the national transmission planner.

The development of separate planning, operational and reliability standards could increase economic costs for consumers where investment in new capacity is above the reliability standard as determined through the Regulatory Investment Test for Transmission (RIT-T). Inefficiencies in funding new capacity could be created where different funding models for generators and consumers are used for a single asset or augmentation relating to network capacity, resulting in an effective cross-subsidy.

The governance arrangements, as outlined in the first interim report, could create inefficiencies where determinations impacting commercial and economic outcomes are removed from the participants who make planning decisions. Specifically, where a network investment is negotiated between a TNSP and a generator yet the cost of access is determined by the Australian Energy Regulator (AER).

Origin does not consider the proposed OFA model should be implemented until such time that a rigorous cost benefit analysis has been completed and the workability of the model has been demonstrated. The cost based on analysis should include the costs to AEMO and wealth transfer between participants in addition to the barriers to entry and cost of acquiring access imposed on incumbent and new entrant generators alike. A proposed change, as significant as the OFA model, should require a high hurdle to implement with clear market benefits with identifiable and quantitative costs and risks.

Should you have any questions or wish to discuss this information further, please contact Ashley Kemp on (02) 9503 5061 or ashley.kemp@originenergy.com.au.

Yours sincerely,

Keith Robertson
Manager – Wholesale and Retail Regulatory Policy
Energy Risk Management

1. Context for reform

The current oversupplied market with declining demand and no new generation planned over the next decade is provided as a rationale for implementing the OFA model at the time proposed. This observation ignores the practical scenarios facing the future of the NEM over the next decade and beyond relating to emerging network limitations and technological developments. It is far from clear that implementing the OFA model is calibrated to Australia's future requirements.

The current market is oversupplied caused by declining demand and government initiatives and subsidies through the Renewable Energy Target and solar PV schemes increasing generation capacity. With no new generation planned for the next decade the challenge for generators is to manage the temporary or permanent withdrawal or mothballing of generation capacity. The future of Australian manufacturing and residential demand is uncertain with forecast load growth load growth forecast to be underpinned by mining activity.

Demand growth attributable to mining is largely focused in Queensland[3] from coal seam gas and other mining activity around the Bowen, Galilee and Surat basins. The emerging network limitation from demand growth in Queensland is the stability constraints limiting the ability of Queensland to import generation from New South Wales. The recent joint RIT-T by TransGrid and PowerLink indicate that market benefits may make an upgrade economic from early 2020 – around the time OFA may be implemented.

It is not clear OFA can address this issue as under transitional arrangements interconnectors are not allocated any access and incumbent Queensland generator are grandfathered access for potentially a decade. Queensland generators could not be expected to fund an upgrade of the QNI interconnector, as this would increase competition, while NSW generators may be indifferent to an upgrade given the potentially significant costs and financial uncertainty for generators funding an upgrade. This uncertainty extends to generators and any augmentation having different asset life cycles. What is clear, however, is Queensland consumers will benefit from an upgrade of QNI at some point in the future that will require a significant investment.

Separately, it is not clear that the OFA would be calibrated to potential future technological and other trends across the NEM. An increase in non-scheduled, distributed generation could arise, driven by an increase in private networks, as network costs incentivise residential and business consumers to disconnect from the main electricity grid. The OFA is unable to equitably allocate risks between generators and other participants given private networks would still require supply from the main network as back-up for a failure of distributed generation.

What is clear is the OFA is not optional and will impose basis risk on all generators that have not undertaken the significant cost of acquiring access. The volume risk from being dispatched below bid offers is not a material risk but the basis risk from funding an acquired level of capacity is not only inherently inefficient but imposes a real risk on all non-firm generators.

Origin does not envisage a plausible scenario in the medium term where OFA would deliver a net benefit.

[3] We note ElectraNet has noted a number of connection enquires related to mining on the Eyre Peninsula and expansion of the Olympic Dam mine in South Australia.

2. *Identifying a problem?*

The objective of the OFA model as outlined in the Transmission Framework Review (TFR) Final Report is to co-optimise investment planning between generation and transmission to minimise the expected total system cost borne by consumers.[4] The objective implies current planning arrangements in the NEM are sub-optimal leading to inflated costs for consumers. The materiality of this hypothesis needs to be quantified given the potential costs and risks the OFA model could impose on participants and consumers.

The AEMC contend that dispatch risk from network congestion may affect the ability of generators to sell forward contracts or increase the price at which they were willing to offer contracts.[5] Rebidding around periods of congestion more generally has been identified as a problem leading to inefficiencies from strategic bidding creating volatile market outcomes, reducing the value of Settlement Residue Auctions (SRAs) and inter-regional trade from instances of negative inter-regional settlement residues.

The AEMC noted, however, the findings of a report by ROAM consulting, commissioned as part of the TFR, that the impact of rebidding around congestion was not material at $3-$15 million per year[6] – a small percentage of total NEM turnover of $6-$12 billion. The AEMC has also previously noted in separate market reviews and determinations that the cost of rebidding around congestion is not material.

> *Analytical work by the AER and the AEMC suggested that productive inefficiencies from dis-orderly bidding have been relatively minor to date. In addition, empirical research from [AEMO] showed that congestion has tended to be transitory and influenced significantly by network outages….*[7]

Separately the AEMC has identified that the cumulative cost of negative inter-regional settlement residues (IRSRs) in the NEM from July 2010 to January 2013 has not been material at $26 million.[8] The cost of inefficiencies from rebidding around congestion and the impact of dispatch risk on generator contracting is, therefore, unlikely to be significant.

Origin considers the AEMC is correct to identify other risks including generator outages and expectations around contract prices and future spot prices as key drivers of contracting behaviour.[9] Generator contracting is a dynamic process utilising underlying generation assets in the spot market, over-the-counter derivatives in the contract market and exchange traded products and in combination in a dynamic trading environment enabling participants to actively manage exposure to the spot market. It is these drivers and not the transitory impact of dispatch risk from congestion that would influence contracting behaviour.

---

[4] AEMC 2013, 'Transmission Frameworks Review, Final Report, 11 April 2013, Sydney. p. 96.
[5] AEMC 2014, 'Optional Firm Access, Design and Testing, First Interim Report, 24 July 2014, Sydney p. 21-22.
[6] Ibid. p. 21.
[7] AEMC 2009, 'Ramp Rates, Market Ancillary Service Offers, and Dispatch Inflexibility, Rule Determination, 15 January 2009, Sydney. p. 14.
[8] AEMC 2013, 'Management of negative inter-regional settlements residues, Issues Paper, 18 April 2013, Sydney. p. 7.
[9] AEMC 2014, 'Optional Firm Access, Design and Testing, First Interim Report, 24 July 2014. p. 21.

Based on past assessments of the cost of rebidding around congestion and the introduction of incentive based regulation to minimise the market impact of network outages, the AEMC has not demonstrated sufficiently that there is a requirement to implement a significant market change. Before further progressing with the OFA, the AEMC should conduct a rigorous cost benefit analysis to assess the cost of implementing the model given the costs from inefficiencies under existing market arrangements have been repeatedly found to be immaterial.

Incentive regulation to mitigate the market impact of congestion

The introduction of the Service Target Performance Incentive Scheme (STPIS) in 2012 by the AER has the potential to decrease the cost of congestion through incentivising TNSPs to schedule network outages at times to minimise market impacts. The AEMC has dismissed market benefits from SPTIS claiming it has only been in place for a limited period of time and there is limited evidence of its success.[10]

Origin has been supportive of the development of the STPIS and the introduction of the market impact component to complement the availability and capacity component of the scheme. While it has been in place for a limited period of time, based on anecdotal evidence, we consider the scheme has been successful in changing TNSP behaviours and limiting the market impact of network outages and congestion more generally. This has been supported by recent publications from the AER[11] and AEMO[12] where the cost impact from congestion from 2010 has been limited and transitory.

3. *Commercial arrangements*

Origin does not consider the OFA model will enhance commercial arrangements in transmission planning. While the OFA seeks to decentralise transmission planning to provide a more commercial framework, to allow generators to signal new network augmentation to provide an agreed level of firm access and connection requirements, these objectives are unlikely to be met. The information and power asymmetry between generators and TNSPs from a commercial generator negotiating with a natural monopoly is likely to introduce significant risks and uncertainties into the transmission planning process leading to market inefficiencies.

The TFR identified the connections process outlined under Clause 5.3 of the National Electricity Rules (NER) created significant inefficiencies for connecting generators through the information and power asymmetries between monopoly TNSPs and connecting generators. The complexities in negotiating a deep network augmentation are likely to amplify the difficulties identified in the connections process leading to generators incurring significant risk in the cost and timing of the network augmentation.

These complexities and difficulties are inherent where a commercial generator is required to negotiate with a natural monopoly. A monopoly TNSPs has earnings based on a regulated rate of return, has an obligation to maintain the transmission network in a safe, secure and reliable condition, balancing generator transfer capability with technical standards outlined in schedule 5.1 and 5.2 of Chapter 5 of the NER. A generator's earnings and obligations, in contrast is derived from revenue from the market to maximise returns for shareholders that can only be realised once the generator is connected to the network.

---

[10] Ibid. p. 32.
[11] AER 2013, 'Request for Rule Change – Requirement for ramp rates and dispatch inflexibility profiles to reflect technical capabilities,' 21 August 2013. pp. 22-25.
[12] AEMO 2014, 'Optional Firm Access, AEMO First interim Report,' 24 July 2014. p. 13.

This can only lead to significant financial uncertainty for generators for transaction costs including extensive technical modelling and environmental and other studies, cost overruns, delayed commissioning of the augmentation and for the asset stranding risk or under-utilisation where market conditions change from the signing of an augmentation agreement and commissioning of the asset.

Investment in new network capacity would be unlikely to be efficient as TNSPs would have a natural incentive for network investment to improve the operation of the network as a whole and increase the size of the regulated asset base. Improved locational signals are more likely to be a theoretical observation as generators make a practical trade off of locating close to a fuel source and transmission network.

Access pricing under the OFA model is not a commercial arrangement determined through negotiation between the generator and TNSP. Developing a prototype pricing model, based on either a Long Run Marginal Cost (LRMC) or Long Run Incremental Cost (LRIC), imposes significant risk and financial uncertainty on the generator and TNSP for either over or underestimating the asset and financing costs for an augmentation. Estimating a standardised approach to costing an augmentation is rendered more difficult by the varying topology between and across different regions. Based on the range of variables impacting the cost of an augmentation, any standardised approach is likely to fail with the cost and risk initially borne by the generator and TNSP but ultimately the consumer.

3.1 Commercial planning framework

The current investment planning arrangements facilitate efficient investment in new network capacity. The RIT-T co-optimises transmission and generation planning by identifying the most technically and commercially feasible option to address an identified need. This extends to an equal consideration of network and non-network options including generation and demand response, providing incentives for TNSPs to make trade-offs between network operation and investment.

The RIT-T process manages the risks inherent in transmission planning through facilitating a transparent consultation process from identifying the need for an augmentation to the range of credible options that could address the identified need at the lowest net cost to consumers. At each successive stage of the consultation process the project specifications are refined to an increasing level of detail to ensure the investment is efficient.

The AER is required to approve projects to allow funding, minimising the risk a project is approved without adequate consultation. Where there has been inadequate consultation stakeholders are able to lodge a complaint with the AER. The AER is able to assess the veracity of the complaint to reject a vexatious complaint or take action against the TNSP where the TNSP has not adhered to the consultation framework to balance competing risks and interests.

The negotiation process around developing a network augmentation could increase the centralisation of the negotiation framework between a generator and the jurisdictional TNSP. This could substantially reduce the level of transparency in identifying the need for the augmentation and assessing the option that is the most commercially and technically feasible as well as concentrate the risk of a project with the proponent generator.

3.2 Locational signals

The OFA is purported to increase locational signals for generators, informing choices as to connect in an area of the network where there may be excess capacity or the costs from connecting in an area that exhibits congestion. This is supposed to be evident through a current lack of location signals under existing arrangements for transmission losses and congestion and interregional price variation.[13]

Origin considers the concept of location signals as an economic concept is not easily applied to the practical operation of the NEM. Locational signals may only be effective in allocating risks between TNSPs and generators for network investment insofar as the generator has a material range of options where to locate. A connecting generator does not have a material choice where the key determinant in where a generator locates is the location of the fuel source. Instances where a generator could have a choice and trade-off between investing in network transmission or transporting a fuel source are limited.

A practical problem associated with locational signals and a lack of generator choice is network congestion is caused by load inasmuch as it is caused by generation. The connection or disconnection of a significant load could significantly impact the level of congestion on different parts of the network as generation flow patterns change to either supply the load or change to supply an alternate load centre where a load disconnects.

There are a number of current processes and publications where information on network performance and planning are available from TNSPs and AEMO, as the National Transmission Planner, including:

- The Nation Transmission Development Plan;
- Annual Planning Reports
- National Electricity Forecasting Report
- Electricity Statement of Opportunities

Transmission loss factors are also published by 1 April each year indicating the losses associated with each generator providing an insight into line loading level in different parts of the network.

3.3 Incentives for TNSPs

Origin does not consider the OFA will incentivise efficient trade-offs between operational and network expenditure or improve financial certainty for generators. The design of the incentive scheme based on a target factor or nested collars and caps could lead to inefficient operational decisions where penalty limits have been reached for TNSPs and generators face uncertainty as the incentive scheme is not intended to compensate a generator for losses incurred but provide a benefit to the market.

The incentive scheme under the OFA is unlikely to increase efficient operational decisions or improve financial certainty for generators. The incentive scheme, as currently designed, disproportionately allocates the risk for a TNSP failing to maintain an agreed level of access to a generator as the scheme is designed to improve efficient market outcomes and not compensate the firm generator when an agreed level of access is not maintained but to penalise the TNSP.

[13] AEMC 2014. p. 35.

The incentive scheme increases the financial risk for generators through the introduction of target factors or t-factors. While the generator may procure a firm level of access, this is discounted or scaled back to limit operational obligations on TNSPs, leaving a generator liable to pay the TNSP when service is available above the t-factor while leaving the generator financially short when the TNSP fails to maintain the access level defined by the t-factor and is exposed to losses in the spot market.

The introduction of nested collars and caps is problematic when caps or collars have been reached within a relevant interval. In effect, the incentive scheme will ceases within a trading interval, day, month or year when the TNSP is no longer liable for failing to maintain an agree level of access. This aspect of the scheme requires further work.

3.4 Inter-regional trade

Inter-regional trade is expected to increase under the OFA as the current non-firm nature of SRAs becomes firm(er) with financial certainty. This expectation is based on the assumption that congestion and bidding resulting in counter economic flows creating negative IRSRs has materially devalued SRAs. This does not reflect the observable reality that the currently low value of SRAs is due to limited regional price separation between regions; the result of an over supplied market.

The AEMC has acknowledged that the commercial arrangements for firm inter-regional access rights under the current proposed model would be problematic:

> *We recognise that one potential negative is that if we were to allocate transitional access today, based on our proposed method, there would be no initial allocation to interconnectors. That is, any firm interconnector rights would need to be underpinned by new interconnector capacity.*[14]

In other words, there are no commercial arrangements for firm interconnectors rights without, what would amount to, significant investment in new network capacity.

3.5 Economic bids

The OFA is intended to increase efficient dispatch by incentivising generators to bid at cost and in merit order. This view is based on the erroneous assumption that an efficient bid should be at cost. This simplistic assumption ignores the multiple faceted aspects to many businesses operating in the NEM with diverse generation portfolios.

This assumption ignores arbitrage opportunities or the ‘spark spread’ between generation and different fuel sources across gas and coal. It also does not reflect strategies to manage long term supply contract and how businesses may value a supply source at any given time given take-or-pay contracts or the short term availability of a fuel source on a spot basis.

The assumption also ignores a whole portfolio view of a business with retail and generation across multiple regions where the availability of generation in one region could impact the bidding behaviour within the same or different region to achieve business objectives.

[14] Ibid. p. 26.

4. Economic impacts

Origin does not consider net economic benefits are achievable under OFA due to problems associated with the commercial arrangements under the model. Based on the objective of OFA, the economic benefit is defined by the extent total system costs could be lowered for consumers. A key contributor to lowering costs for consumers is lowering network costs and wholesale energy costs through improvements in contracting and bidding.

Economic benefits through lower transmission costs based on the objectives of OFA could be expected to be realised through the planning process, the location and size of network augmentations and lower costs through effective incentive based regulation. Economic benefit from improved generator dispatch is achieved through improved contracting, inter-regional trade and economic bidding based on the objectives of OFA.

The AEMC identified an economic benefit of a lower risk-adjusted cost of capital resulting in lower financial costs for investors in the NEM.[15] Objectives consider that the OFA model will reduce the risk profile for investing in participants that operate in the NEM. The OFA replaces volume risk for basis risk and exposes non-firm generators to making payments to firm generators. This is not an optimal outcome for the market as a whole when the current cost of congestion is low.

4.1 Commercial planning framework

The purpose of the RIT-T is to identify a credible option that maximises the present value of net economic benefit of all participants and consumers in the NEM.[16] The RIT-T process allows for the consideration of a range of market benefits, including competition benefits. The AEMC has not demonstrated that the current RIT-T process has approved uneconomic network or other solutions to an identified need. The application of the RIT-T, in a number or instances, has increased flexibility in the planning process where the timing of an investment could be delayed pending a number of event triggers.[17]

The OFA introduces uncertainty into the planning process that could increase costs for consumers and introduce other inefficiencies. The firm access planning standard and operational standard could increase costs for consumers through development above the reliability standard. The cost recovery mechanism would simply shift from Transmission Use of System (TUoS) changes to higher wholesale electricity prices as generators seek to recover costs.

The outcome of shifting the cost recovery mechanism from TUoS changes to the generator could create volatile longer term market outcomes. Under the current oversupplied market, the cost incurred by a generator would be unlikely to be recovered due to low spot market prices. While this would decrease the value of the generator in the short term, over the longer term, as the supply and demand balance tightens, the generator would need to recover costs through the wholesale spot market, leading to more volatile spot market outcomes.

The introduction of reliability access introduces potentially significant inefficiencies by incorporating two funding models into a single asset. Reliability access introduces a cross subsidy between generators and consumers as the generator incurs a fixed long term

[15] Ibid. p. 21.
[16] NER Clause 5.6.5B (b).
[17] For example, development of the Eyre Peninsula in SA, upgrades around the Bowen Basin in Qld and the QNI upgrade.

contract while the consumers would have a variable cost through TUoS. This could create a significant cross-subsidy from generators to consumers as load increases over time.

The AEMC has not demonstrated why generators should subsidise reliability access when, if assessed adequately under the RIT-T process, the standard should reflect a level of reliability people are willing to pay for or a frequency and duration of supply interruption that people are willing to accept, if the Value of Customer Reliability values are determined accurately.

4.2 Locational signals

As indicated above in section 2.2, Origin considers the economic concept of locational signals is largely theoretical and of limited applicability to the NEM. A generator's location decision is largely determined by the location of fuel source with the location on a transmission network a secondary consideration. Generators currently factor constraints into their location decisions.

4.3 Incentives for TNSPs

Origin does not consider economic benefits will be realised through the introduction of the OFA incentive scheme. A primary reason for this is it could be unlikely for further reductions in costs where caps or collars reached and TNSP no longer incentivised. To the extent that generators are required to pay TNSPs a bonus payment for access above the t-factor, the generator may seek to recover these costs through higher pool prices.

Origin recognises the behavioural shift by TNSPs under the existing STPIS resulting in less volatile wholesale prices associated with network outages. The capacity component under STPIS is also likely to lead to lower wholesale prices where congestion can be relieved through incremental investments. The success and level of interest in the scheme is demonstrated by a number of TNSPs wanting to participate in the scheme earlier before commencement of a new regulatory control period.

4.4 Inter-regional trade

By definition firm inter-regional trade will not create economic benefits and lower costs to consumers. As noted in section 2.4, under the transitional allocation methodology, interconnectors are allocated no access. Any firm interconnector rights would need to be underpinned by new interconnector capacity. Investment in new interconnector capacity is likely to impose significant cost[18] on the proponent that would need to be recovered through higher hedging costs or pool prices.

Network investment is inherently expensive due to the scale of investments required to enhance interconnector capacity between regions. Recent approved upgrades of the Heywood interconnector and reviews of the QNI upgrade suggest, while not perfect, a transparent consultation process to identify the most technically and commercially feasible option under the RIT-T process is likely to produce investment at the lowest cost for consumers and enhance inter-regional trade.

[18] An ElectraNet and AEMO study indicated a 500kV double circuit transmission line could cost $2.5 million per km while a 220kV to 330kV line could cost $1 million per km. High voltage transformers and associated switchgear could cost $20-$45 million.

4.5 Economic bids

The AEMC considered a positive impact under the introduction of the OFA model is lower wholesale price volatility from the removal of incentives for bidding behaviour associated with managing congestion. Origin considers the access settlement component of the OFA model that AEMO was tasked to analyse indicated access settlement is unlikely to remove options for strategic bidding.

In commenting on the potential impact of the OFA model, through access settlement to influence bidding behaviour and spot market outcomes:

> *AEMO has reviewed recent events of non-cost reflective offers to test this hypothesis. In each of these events, generator behaviours were also affected by a number of market design and structural issues which are outside of the scope of access settlement. It will be difficult to identify the incremental benefits that arise from access settlement alone.*[19]

Origin agrees with the AEMO assessment and any changes to bidding incentives could lead to other bidding behaviours.

5. Technical outcomes

There are a number of technical outcomes to consider with the proposed implementation of the OFA model: technical design outcomes under negotiation between TNSP and generators; technical issues with transitional access and staged implementation; and technical modelling of incremental benefits of design options in alleviating congestion and delivering financial certainty to generators.

As outlined in section 2, Origin considered the RIT-T process could produce better commercial outcomes through the transparent consultation process than through a non-transparent negotiation that would involve information and power asymmetries under the OFA model. This consideration extends to identifying and investing in an option that is the most technically feasible. It is difficult to identify how an optimal design outcome on a technical basis can be developed if a full range of options and variables are not openly considered.

The transitional access model developed by the AEMC has significant flaws and could potentially create a significant dead weight cost on generators located near interconnectors. This outcome would follow from the erroneous assumption under the transitional model that required a generator's sent out energy to be consumed at the RRN under conditions of a non-existent constraint. The transitional access arrangement could also create barriers to entry for a new generator entering the market.

The implementation of the OFA also involves significant risks. Issues that could significantly increase the complexity of the model is where, if it is implemented in only one or a limited number of regions, requiring constraints to be modified for variables that are located in an OFA or non-OFA region. A situation where some regions 'opt-out' of participating could make the model unworkable while implementing the model across the NEM would significantly increase the risk for the market where unintended consequences emerge.

A critical objective of OFA is to create financial certainty for generators. It could be difficult to model and predict the benefit to the generator for a given augmentation in

[19] AEMO 2014. p. 3.

relieving a defined level of network congestion or, put differently, modelling the level of firm access. The modelling could be expected to be expensive and occur early in the negotiation process where the augmentation enquiry is of an indicative or 'tyre kicking' nature. This modelling and ability to predict the actual or firm level of access could impose significant financial uncertainty on a generator and/or TNSP.

5.1 Commercial planning framework

Financial certainty for generators in the planning process may not be realised where modelling is unable to determine whether a given reduction in congestion could enable an assessment of financial savings from making a new network investment. The cost of undertaking modelling potential financial benefits could likely to significant and be imposed on the generator early in the augmentation process. These costs could also be imposed on a generator whether the generator progresses with an augmentation or only makes an enquiry.

5.2 Locational signals

Locational signals under the transitional arrangements are distorted by treatment of generators located away from the RRN and near interconnectors. The allocation of transitional access under the model is flawed. The model assumes a generation flow path from connection point to the RRN within a region when load located remotely from the RRN by be the actual physical delivery point.

5.3 Incentives for TNSPs

The cash flows and objectives of the OFA incentive scheme are not aligned with the objectives of the firm access standard or the beneficiary from enhanced network capacity. Under the STPIS the TNSP reward is funded through TUOS charges as a percentage of the TNSPs maximum allowable revenue. The justification for this could be that, as spot prices are lower and less volatile, then consumers receive a benefit in the form of lower prices.

Under the OFA incentive scheme, the firm access the generator acquires is discounted by the t-factor. The AEMC has not demonstrated why a generator that procures a defined level of access should have the level of access discounted by, as proposed, the AER. Moreover, it is not clear why the generator should pay the TNSP a reward payment when a level of access is provided when a major beneficiary of the increase is consumers in the form of lower prices?

5.4 Inter-regional trade

As outlined in section 2.4 and 3.4, under the proposed transitional access model there is no access allocated to interconnectors and therefore there is no inter-regional trade until transitional arrangement have been completed. That is, any firm interconnector rights would need to be underpinned by new interconnector capacity.

5.5 Economic bids

AEMO analysis indicates access settlement is unlikely to remove options for strategic bidding as outlined in section 3.5.

Appendix 1: Origin submission to the AEMO OFA First Interim Report.

4 September 2014

Mr Ben Skinner
Specialist Market Development
Australian Energy Market operator
GPO Box 2008
Melbourne Vic 3001

Submitted online: www.OFAConsultations@aemo.com.au

Dear Mr Skinner

Optional Firm Access – First Interim Report

Origin Energy (Origin) appreciates the opportunity to provide comments to the Australian Energy Market Operator (AEMO) Optional Firm Access (OFA) First Interim Report. Origin understands the terms of reference provided by the Standing Council on Energy and Resources (SCER) tasked AEMO to determine the functional design of the access settlement system consistent with the Australian Energy Market Commission (AEMC) OFA design parameters.

AEMO analysis has indicated that it is difficult to clearly identify benefits from access settlements:

> *AEMO has reviewed recent events of non-cost reflective offers in order to test this hypothesis. In each of these events, generator behaviours were also affected by a number of market design and structural issues which are outside of the scope access settlement. It will be difficult to identify the incremental benefits that arise from access settlement alone.*[20]

Origin considers AEMO has identified two fundamental issues inherent in the design of the OFA model that increase complexity and questions the practicality of the model:

- Linking access capacity in settlement and treatment of auxiliary loads and marginal loss factors; and
- Discrepancy between 5 minute dispatch and 30 minute trading intervals and calculating flowgate prices within a trading interval.

Origin considers AEMO has undertaken detailed technical analysis to gain a comprehensive understanding of access settlement. The analysis has revealed the difficulty in clearly identifying benefits under access settlements. AEMO's analysis highlights the complex, dynamic and interrelated facets in the National Electricity Market (NEM) in how spot market outcomes are determined with any benefits from changing bidding behaviours being unclear.

---

[20] AEMO 2014, 'Optional Firm Access AEMO First Interim Report,' July 2014, Melbourne p. 3.

Access settlement, if implemented, could impose significant changes to the operation of the NEM. The ability and practicality of access settlement to shift settlement from dispatch to capacity, to enable the OFA objectives to be achieved, should therefore, be rigorously assessed against the cost of implementation. The potential for unintended consequences through any stagged implementation should also be assessed in determining whether to implement access settlement.

Should you have any questions or wish to discuss this information further, please contact Ashley Kemp on (02) 9503 5061 or ashley.kemp@originenergy.com.au.

Yours sincerely,

Keith Robertson
Manager – Wholesale and Retail Regulatory Policy
Energy Risk Management

1. Limited identifiable benefits in access settlement

Origin supports the approach of AEMO in determining whether access settlement is practical to implement and how it is likely to influence dispatch. In assessing the design elements in access settlement AEMO has been required to assess the practicality of introducing access settlement and whether access settlement will lead to a perceived improvement in generator bidding behaviour.

Origin is supportive of the approach AEMO has taken to testing with a detailed technical platform notwithstanding the constraints from testing access settlements over a limited historical period. Such an approach is likely to be more rigorous and closer to power system operating conditions than stylised economic modelling. AEMO indicated however, that it is difficult to clearly identify benefits from access settlements from testing:

> *AEMO has reviewed recent events of non-cost reflective offers in order to test this hypothesis. In each of these events, generator behaviours were also affected by a number of market design and structural issues which are outside of the scope access settlement. It will be difficult to identify the incremental benefits that arise from access settlement alone.*[21]

AEMO has also identified a number of potential aspects under access settlement where it may not be able to achieve its stated objectives.[22]

2. Access settlement design

The Standing Council on Energy and Resources tasked AEMO to design and develop an implementation plan for the access settlement system consistent with the AEMC design parameters. AEMO has identified a number of impractical and complex design elements under access settlements that could lead to inefficiencies where access settlement be implemented. The practical difficulties in designing and implementing access settlement are derived from the approach of the AEMC through the Transmission Frameworks Review (TFR) to decouple access and dispatch and link capacity with access.

AEMO has identified two fundamental design issues with access settlement that determine the practicality and workability of the model:

- Linking access with capacity in settlement; and
- The discrepancy between 5 minute dispatch and 30 minute trading intervals.

Settlement based on capacity

As outlined in the Optional Firm Access Technical Report, access settlement is the process that de-links dispatch from access. As opposed to current arrangements where settlement is derived from dispatch outcomes, settlement outcomes will be derived from

[21] AEMO 2014. p. 3.
[22] Ibid. p. 17.

generator capacity entitlements under the firm access standard. The intent of access settlement is to shift from settlements derived from sent out energy to settlement derived from an acquired financial capacity.

AEMO has identified a potentially significant issue with the design of access settlement with the treatment of ancillary loads.[23] Under current arrangements, a generator receives a dispatch target incorporating total generation with auxiliary load deducted from sent-out generation. Under access settlement, as auxiliary loads are factored into dispatch, they could be settled at the local flow gate price. This could create an anomaly where the auxiliary load is settled based on the local flowgate price rather than the Regional Reference Node (RRP) potentially leading to negative settlement residues.

The practicality of grandfathering existing arrangements within access settlements can only be measured against the practicality of access settlements in total. Permanent carve-outs and exemptions for specific aspects within NEM power system operations are likely to lead to inefficiencies and question the workability of the model more generally.

Five minute dispatch and thirty minute trading intervals

The approach of the AEMC to the calculation of access settlements is to retain existing market parameters where trading intervals (TI) are 30 minute periods with settlement calculated on the basis of 5 minute dispatch intervals (DI). This adds additional complexity to the settlements process by incorporating the RRP in addition to the marginal constraint value or flowgate price for every dispatch interval where a constraint binds at a flowgate through a trading interval.

Access settlement requires the marginal value of the constraint to be incorporated into the settlements process, reflecting the flowgate price. This complicates the settlement process, as identified in the OFA Technical Report, when constraints do not bind across a whole TI and instead bind for a single DI or over several DIs but with a varying marginal constraint value. Origin understands the approach of AEMO to resolving the additional complexity is to treat each DI where a constraint binds is to treat the DI as though the constraint bound for the TI and divide the constraints marginal value or flowgate price by 6 – the number for DIs in a TI.

An additional complexity identified by AEMO with access settlements is incorporating the coefficient for separate generating units at a power station into settlements when they have different coefficients. Origin agrees with AEMO that different generating units at a power station have separate coefficients where the units are connected to different parts of the transmission network. Eraring, for example, has different coefficients for units 1-2 and 3-4 being connected to the 330kV and 500kV networks respectively.

AEMO has identified a solution to this issue by having less granular dispatch unit identifiers to the generating unit level to a coefficient at the level of the power station. While AEMO have identified a potentially practical solution to the identified problem, it does so in a less efficient manner to how units are currently identified.

Under existing arrangements, a binding constraint exposes generators to dispatch or volume risk associated with being constrained down. This is easily resolved through the settlements process where the marginal value of the constraint is not relevant and the

[23] It is unclear if the problem identified by AEMO relating to auxiliary load would extend to electrical loss incurred within a power station, for example, through station transformers.

sent-out generation, adjusted for marginal loss factors, is settled at the RRP. Analytical work on access settlement by AEMO suggests the settlements process would increase in complexity and be less efficient raising a question as to whether it would be consistent with the National Electricity Objective.

3. *Transitional arrangements*

The SCER terms of reference tasked AEMO to recommend an implementation plan for access settlements reflecting the AEMC's recommendation on the most efficient option for staging implementation. The design aspects of access settlement would render a staged implementation by jurisdiction or region impractical and complicate the settlements process.

Access settlement involves the calculation of a flowgate price in addition to the RRP in determining the price for a TI. In practical terms this involves tagging constraints to enable the marginal value of the constraint to be calculated in the settlements process. Numerous constraints, however, have elements that are located in regions outside the region experiencing an intra-regional constraint.

Origin recognises AEMO is able to tag or tag select elements in a constraint equation. Requiring AEMO, however, to pick through constraints for elements that should be included or excluded in the settlements process increases the complexity and the practically of any stagged implementation of access settlement.

4. *Is access settlement equitable?*

AEMO identified an issue under access settlement where non-scheduled market generation would receive the RRP and not be exposed to the local flowgate price under periods of congestion. Origin agrees with AEMO that excluding non-scheduled generation makes access settlement problematic given it may not apply across all generation systems but its raises a more poignant question as to whether access settlements and OFA more generally is equitable.

While we note this specific issue is beyond the remit of AEMO, there is a question as to why market scheduled generators should be exposed to the basis risk introduced by access settlement when the generator may have not directly contributed to congestion. Line loading and generation flow paths are impacted by a number of factors including load and line ratings. A significant load could, for example, decrease line loading when it is located near a generator but increase line loading where it is located a distance from a generator. Conversely, the loss of significant load could impact the level of line loading depending on the location on the network. Is it equitable to expose a generator to basis risk arising from congestion when the generator may not have caused congestion?