2019 COGATI IMPLEMENTATION

Response to AEMC Coordination of Generation and Transmission Investment Reform - Access Reform directions paper

August 2019

1. Summary

Stanwell welcomes the opportunity to comment on the Coordination of Generation and Transmission Investment (COGATI) directions paper on access reform.

Stanwell acknowledges that access arrangements have been an ongoing debate since before the National Electricity Market (NEM) inception and that the current generation investment environment is driving greater congestion and transmission losses than have historically been observed.

The NEM is transitioning from a passive demand side and large, centralised, synchronous, scheduled supply side to a more distributed, two-sided, less synchronous system with more supply side variability. The challenges of the former were simpler than the challenges of the latter and in this environment all aspects of market design are being reconsidered.

Change is desirable where the benefits outweigh the detriments across a range of plausible future scenarios. Proposed change should also be transparently measured against alternative approaches which achieve the same or similar goals to determine the efficient path forward. The COGATI proposal as currently described in the directions paper does not pass this test.

The lack of transparency and detail of the framework design is compounded by the timeframes which the AEMC has set to recommend the final design (December 2019) and implement the outcomes (2022).

The COGATI proposal exhibits some similarities to the Optional Firm Access (OFA) proposal which was initially presented by the AEMC in the Transmission Frameworks Review (2010-2013).[1] That model was investigated in detail (2014-2015) and determined not to be fit for purpose. By way of comparative example, OFA had an intended implementation date of 2022[2]; the final report extended over 3 volumes and 750 plus pages and included pricing models and transitional arrangements developed through extended and detailed consultation with industry.

The COGATI directions paper at 139 pages only addresses the wholesale pricing element of the proposed reform, and this analysis is limited to simplified conceptual examples. Despite this the AEMC have again recommended a 2022 start for the reform of what is described in the directions paper as a "*central design choice of the NEM*"[3].

Access reform is complex and can't be rushed. There are many risks and intricacies that are not helped by the topology of the NEM. Stanwell wants to ensure that any reform of this magnitude has had appropriate consideration to minimise unintended consequences, and to ensure industry is adequately prepared to adapt to changes.

It is difficult to provide thorough comment on the reform package given the directions paper focusses primarily on one of the three components. To make a proper, holistic assessment as the process progresses, Stanwell requests the AEMC:

- Clarify and edify the issues access reform is intended to address, those it is not, and the extent and relativity of the issues;
- Clarify why access reform and the designs chosen have been deemed to be the most efficient in addressing the identified issues;
- Be transparent about how the development of COGATI has interfaced with the Energy Security Board's (ESB's) market reform process to provide clarity about how they complement;
- Acknowledge how access reform would integrate with potential new market arrangements and the changing awareness of system security requirements and thus be fit-for-purpose now and into the future; and
- Provide at least qualitative but preferably quantitative analysis of the market risks imposed, with equal treatment to the risks of the proposed reform that is given to the benefits.

While the proposal as a whole remains insufficiently defined, Stanwell has provided detailed comment on the aspects considered in the directions paper.

Stanwell considers that the directions paper has highlighted an existing pool of difficult-to-access information, the transparent publication of which is likely to be

[1] www.aemc.gov.au/markets-reviews-advice/transmission-frameworks-review

[2] www.aemc.gov.au/sites/default/files/content/1f15553d-e513-4d9a-9b96-f9549b9ae589/First-Interim-Report.pdf

[3] AEMC, COGATI Directions Paper, p (ii)

a no-regrets reform[4]. As such, Stanwell recommends that the AEMC **should confirm when and at what cost AEMO could begin publishing locational information in new database tables.**

Stanwell welcomes the opportunity to further discuss this submission. Please contact Evan Jones on (07) 3228 4536 or evan.jones@stanwell.com.

2. Context

The broader context within which access reform is considered needs greater clarification to assist industry to adapt efficiently to the larger reform. In particular, Stanwell would appreciate greater information about how COGATI interfaces with the ESB 2025 market reform, the Integrated System Plan (ISP) and the Australian Energy Market Operator's (AEMO's) Renewable Integration Study (RIS).

It would also be useful to understand how demand response aggregators (DRA) as described in the Wholesale Demand Response Mechanism draft determination will be treated under the proposed reform.[5]

As the COGATI proposal appears limited to the provision of bulk energy, further information is also required on how the reform would relate to processes addressing other technical and economic challenges facing the NEM such as the definition and procurement of system strength, inertia and frequency control.

It would also be constructive to have an understanding of what outcomes of the OFA process have fed into the design considerations here.

Interaction with the ESB's Post-2025 market design process

The AEMC has stated that they, as a member organisation of the ESB, are working closely with the ESB to ensure alignment of COGATI with the 2025 market reform process. Industry needs transparency of any work being undertaken in conjunction with the ESB concerning the consistency between the COGATI proposed changes and the ESB's proposed changes.

The ESB is scheduled to present market design options to the Council of Australian Governments (COAG) Energy Council in December 2019 at the same time the detailed design of COGATI is to be delivered. The ESB is not ruling out any options in its reform process[6] including mechanisms such as capacity markets that are not easily compatible with some of the design aspects identified in the directions paper. Given the concurrent timing, the AEMC needs to clearly explain how any access reform will work under or conflict with any potential changes to the market design.

This is necessary to reduce the concern of market participants that two reform processes with long time horizons and potentially considerable overlap may unnecessarily increase the amount of disruption to the NEM and associated markets. It would also help industry contribute more effectively to the respective consultation processes.

Interaction with the AEMO's ISP

The directions paper outlines the intent to integrate AEMO's ISP into the access reform which is logical for overall system planning considerations. Given the ISP is a national transmission planning document and not a market or operational model, local assessments would still need to be considered based on network requirements and pricing. There may be a role for the ISP to interface with Transmission Network Service Providers' (TNSPs) assessments in terms of ensuring that the prices of transmission hedges are consistent within the market context. TNSPs are still best placed to understand the limits of their own networks and connection requirements. The paper identifies the local limitations of the ISP in indicating that renewable energy zones (REZs) may evolve that have not been identified in the ISP.

The other consideration that the AEMC needs to detail is how government funding of infrastructure will be incorporated and managed into any access reform. Currently, the ESB is seeking to progress Group 1 projects identified in the ISP while projects such as Snowy 2.0 and the potential funding of its related network infrastructure have created other market distortions[7]. Any access reform must provide some form of risk mitigation in this context to be viable.

[4] Refer "Improving Locational Signals" section, page 9 of this submission.
[5] www.aemc.gov.au/sites/default/files/2019-07/Draft%20determination%20-%20ERC0247%20-%20Wholesale%20demand%20response%20mechanism.pdf
[6] ESB, Technical Working Group meeting, 22 July 2019
[7] This is being funded by the NSW Transmission Infrastructure Strategy which seeks to boost interconnection with Victoria, South Australia and Queensland, unlock more power from the Snowy Hydro Scheme and increase capacity by prioritising Energy Zones. https://energy.nsw.gov.au/media/1431/download

Interaction with the AEMO's RIS

AEMO's RIS focuses on quantifying the technical renewable penetration limits of the power system for a projected generation mix and network configuration in 2025.[8] This is similar to work that was undertaken by Eirgrid in Ireland. Given a key objective of access reform is to provide greater certainty to new generation, this study would be necessary to inform any design as it will provide an understanding of the system security limits of the network. It is likely that these limits will not be able to be remedied by localised network augmentation. Any access reform thus needs to consider these system limits and presents questions about whether or not new connections should be permitted if the limit is forecast to be exceeded.

Interaction with new market Rules and liquidity support

The market has undergone recent change including the Retailer Reliability Obligation (RRO) which commenced on the 1 July 2019 but whose market impact has yet to materialise, and the ASX market making mechanism for which Stanwell is a registered market maker.

In this context, the proposed access changes will have impacts beyond the dispatch and payment of generation that have not been adequately considered. Locational Marginal Pricing (LMP) is likely to impact obligations and contracts under both of these schemes and increase hedging costs. Given that even generators who have purchased transmission hedges will initially have little transparency as to their firmness it is likely that hedge liquidity will reduce. Unhedged generators and their financiers may perceive significantly higher risk in participation and reduce or potentially cease their participation in traditional contract markets. Liquidity was identified as a major issue in the New Zealand market[9].

The role of market maker is to support liquidity but under the proposed reform, the market maker may have to also purchase transmission hedges or incur basis risk, increasing overall costs or, conversely, decreasing participation in the market making mechanism.

Given that entities do not have clarity over their RRO obligations until they are declared at T-3 and then T-1 by AEMO, the risk of managing these obligations increases if some generators have transmission hedges and others not.

Stanwell does not consider these questions have been given adequate consideration when both the RRO and ASX scheme have not been given time to integrate into the market and demonstrate outcomes.

In the directions paper, the AEMC indicated that liquidity issues may not arise because in overseas markets with nodal pricing, contracts are still focussed around several key nodes. Given the experience in New Zealand, it would be useful for the AEMC to detail this assessment more clearly. Stanwell notes that markets in the United States have contract liquidity at their nodes because they are significantly more meshed and interconnected as well as having more load centres. PJM for example has over 10,000 pricing nodes, with many pathways to these nodes. The international experience of pricing nodes and liquidity may not be directly transferable to the NEM because of the markedly different (linear) topology of the NEM compared to international networks.

System security considerations

The discussion paper focuses largely on issues with congestion and investment risk only touching upon system security in the context of reduced system strength in certain parts of the network to which generators are seeking connection.

In their submissions AEMO, TasNetworks and others indicated that any processes should not be restricted to thermal constraints but on a holistic view of all system limits. Stanwell agrees that a broader view is required but the benefits of doing so will only be fully achieved if we extend the focus beyond the current challenges in delivering bulk energy. That is, what will be needed from the transmission system in the future if the network topology is different, and then determining the approach that is longer-term while allowing for transition. Addressing only the challenges apparent today may provide a transitionary solution but will unlikely deliver a fit-for-purpose framework.

Some areas that may need to be considered include:

Operational limitations/realities

The discussion paper has failed to consider operational realities and how they may change as the system evolves. An example provided of how the transmission hedges would work was that if a wind generator was constrained off/down for security reasons but had purchased a hedge, then it may not

[8] www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Future-Energy-Systems/Renewable-Integration-Study
[9] James Flexman presentation at AEMC COGATI Forum, 8 July 2019

receive compensation as the limitation is not locational. However if the wind generator were also behind a binding constraint it would receive compensation through the transmission hedge despite there being no impact on its dispatch.

AEMO's current work to understand the level of non-synchronous generation that can be accommodated on the power system without compromising system security has to be treated as input into access reform. The COGATI proposal needs to consider how and whether TNSPs are equipped to perform the necessary simultaneous feasibility studies that would determine the volume of access that could be validly purchased.

Stanwell would also like clarification on how the pricing and transmission hedges would factor in the different physical characteristics of each generating plant. Plants aren't equal in their flexibility, and larger generators need to be constrained on at times due to their physical limitations.

Market design

- **Market signals** – Locational Marginal Pricing (LMP) as outlined in the paper do not represent the full underlying cost of future generation as it only incorporates bulk energy. It has been acknowledged that market signals will need to evolve so that they are aligned with the physical needs of the power system and value the broader capability required for reliable and secure operation. This may include potential markets for services such as inertia, fast frequency response, primary frequency response, voltage, system strength, etc.
- **Structure of the spot market** – given the increased quantum of zero SRMC generation in the supply market, is it appropriate to assume that the spot market should or will operate on a marginal cost basis in the future? As discussed in Yarrow[10], efficient bidding in an energy-only wholesale market is achieved when pricing reflects economic costs, not incurred (i.e. SRMC) costs.
- **Number of spot markets** – currently, energy only is traded on the spot market and, while there are eight frequency control ancillary service (FCAS) markets, the quantum and procurement is the responsibility of AEMO. As the system evolves, it is not implausible that some system services will be highly valued, and creating spot markets or at least price signals for them may be an efficient approach.
- **Granularity of spot markets** – emerging challenges such as system strength lend themselves to more localised solutions than are available in a region-wide pricing, dispatch and settlement regime.

The directions paper repeatedly states that the need for reform relies on the fact that a generator's revenue is a direct function of its physical dispatch. This will not necessarily be true in future and any LMP framework needs to reflect this.

New business models

There are a number of alternate ways in which to utilise network capacity and share assets that are emerging. One example is bilateral contracts between new generators seeking connection and existing synchronous generation that facilitates the provision of system services such as system strength. These arrangements utilise existing assets and capacity to meet the generator connection standards, representing an effective and overall more efficient solution. The reforms proposed in COGATI have not given consideration to how they may stymie such new operating practices, and may create barriers to these more efficient approaches.

Dispatch mechanisms

Many of the design discussions have been justified on the basis that alternatives would require changes to the NEM dispatch engine (NEMDE). This is short-sighted as there will be necessary changes to NEMDE to accommodate future market design aspects, so this is not an adequate reason to dismiss potentially more efficient frameworks.

Grandfathering

If the AEMC are to progress this reform, of primary concern to all generators is the scope and length of grandfathering arrangements for incumbent generators. These arrangements should reflect the stated intent to improve certainty of generator access to market even if subsequent parties connect to the network and congestion arises.

Without information about these high-level design choices, market participants are not able to make meaningful comment on the directions paper.

[10] Yarrow & Decker, *Bidding in energy-only wholesale electricity markets*, Final-report, November 2014

Grandfathering arrangements, combined with access pricing and firmness arrangements and TNSP compensation schemes are likely to impact on related issues such as closure dates and overhaul planning.

Access pricing

Under the proposed access regime reform, transmission hedges will play a critical role in the continued profitability of generators. The lack of detail about access pricing means generators are unable to assess how the proposed changes will affect their businesses, the market and the industry, and hence are not able to provide even qualified comments about this major part of the proposed access reforms.

3. Implementation timeline

The proposed timeline for developing access reform does not allow adequate time in either the development or implementation stages. This is evident in the AEMC's identification of a significant body of analysis and assessment that needs to be undertaken.

Even in the event that access reform is the best way to address some of the issues currently facing the market, finalising the recommended rule change by December 2019 does not allow enough time to finalise the details of the reform.

As experienced during the OFA process, there are difficult issues that need to be addressed up front to ensure the reform works as intended (i.e. avoids inconsistencies and unintended consequences), rather than deferred until later in the process.

Lessons can also be learnt from the RRO implementation process where the legislation was passed before the details were defined. Industry will be aware of their obligations in August, however, the guidelines and processes are still being determined, both of which impose a cost and risk to industry and ultimately consumers.

Industry can best adapt when the essence of the detail and assessment is determined as part of the consultation process rather than ex-post. This is particularly true for such a complex reform as COGATI.

Interaction with timing of other major reviews and rule change processes

There are currently a number of significant market design changes underway, the timeline of key milestones and implementation detailed in Figure 1~~Figure 1~~.

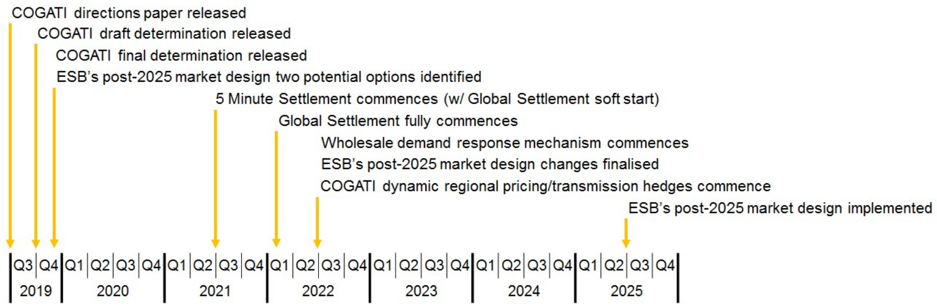

Figure 1: Timeline of current market design changes

The overlapping implementation of these market design changes does not allow the opportunity for the implementation of each individual change to be observed and assessed to determine the impacts of the change against their intended objectives and whether there have been any unintended consequences.

4. Benefits and costs of access reform

The directions paper highlights a number of benefits of the proposed access reform which address three inter-related aspects of the current transmission access framework:

- Wholesale electricity pricing;
- Financial risk management; and
- Transmission planning and operation.

It is also important to consider the proposed benefits and costs against the following reasons for change identified by the AEMC:

- "Generators: Require greater certainty about the long-term profitability of their assets even if subsequent parties connect to the network and congestion arises.
- Consumers: Concerned about projected costs and increased bills.

- TNSPs: Concerned about changes to their rate of return and uncertainty being created by the suggestion of asset write-downs. They are also overwhelmed by the volume and scale of connection enquiries,
- Generators and TNSPs face challenges with the coordination required for the current 'do no harm' framework for system strength."[11]

Table 1 summarises Stanwell's assessment of the benefits against the identified issues to be addressed as understood by the current level of detail in the directions paper. As the directions paper focusses on wholesale pricing there remain critical areas that require consideration before the draft determination is made.

Identified needs	Generator certainty	Costs to consumers	TNSP asset certainty	Reduce work of TNSPs and AEMO	Coordination of system strength requirements
Wholesale electricity pricing					
Locational signals	?	×	×	×	×
Efficient dispatch	?	×	×	N/A	×
Financial Risk Management					
Transmission hedges	×	×	✓	×	×
Planning and operation of network					
Generators inform transmission planning	×	×	?	×	×
Co-optimise investment	×	?	?	×	×

Table 1: Summary table of the impact of key COGATI components on identified needs

[11] AEMC, COGATI Directions Paper, p (i)

Wholesale electricity pricing

The discussion paper outlines two key objectives for locational marginal pricing (LMP):

- To provide better locational signals to generators; and
- To reduce disorderly bidding.

The paper also states that this would allocate no new risk to generators as it would simply shift the volume risk to price risk.

Improving locational signals

The directions paper acknowledges there is currently a range of locational signals for the NEM, both published (transmission losses, congestion and inter-regional price variations) and unpublished (NEM dispatch engine process), but these locational signals are "*incomplete and imprecise*"[12].

Stanwell contends that improving the scope and accuracy of currently available locational signals and publishing currently unavailable locational signals would go a long way to address concerns about the locational decisions being made by new project proponents. The AEMC should provide analysis showing the costs, risks and benefits of the COGATI LMP proposal compared to other access reforms including incremental reform such as information provision.

Stanwell expects that provision of additional information would be significantly cheaper and faster to implement than the provision of that information *and* an overhaul of fundamental market systems. Given that improved information and transparency is a necessity under either approach, **AEMO should publish these locational signals as soon as is practical,** and in any event no later than by 2022 (in line with the AEMC's implementation timeframe). Specifically, AEMO should publish LMP and participation factors to new database tables to minimise the impact on existing systems and processes.

Publishing this information without concurrently relying on it for everything from investment signals to settlement will allow gaps and inconsistencies to be worked through. For example it is currently known that constraints have different formulations in 30 minute pre-dispatch, 5 minute pre-dispatch and dispatch.

[12] AEMC, COGATI Directions Paper, p 14

The directions paper does not go into adequate detail about many aspects of the LMP design including:

Locational pre-dispatch (not identified)

Generators (and scheduled loads and demand response) would require LMP-based pre-dispatch in order to be able to effectively manage their operation. While each scheduled generator currently receives pre-dispatch energy targets which are effectively based on LMP (through constraint effects) they do not receive the LMP itself.

During the 5 minute settlement (5MS) implementation process, industry requested that pre-dispatch to the 5-minute level be extended beyond the one hour nominated by AEMO. This was declined based on the cost and effort to AEMO to implement.[13] Stanwell anticipates that amending pre-dispatch to publish multiple locations within a region would face similar challenges and considers the AEMC should include a specific estimate of the cost and timeframe for AEMO to achieve this if required. The AEMC should also allow for reasonable participant time and effort to implement systems or upgrades which must necessarily occur after significant elements of AEMO's process is complete.

Marginal Loss Factors (not addressed)

LMP will have no impact on marginal loss factors (MLFs) as currently designed except by coincidence, and so will not provide investment certainty to generators from changing MLFs. A future investment in nearby generation will still impact total flows and therefore losses across the network, as is the case in current market design

How MLFs are to be treated needs to be clarified. Depending on how they are used, there may need to be a review of their methodology. Presently, generators bid at the station and MLF applies to that offer to get to at-node price. The at-node price is used for price-setting both in energy and the marginal price of constraints under current market design. This implies that the locational marginal price upstream of a constraint will include the effect of losses across the line which the generator is being restricted from accessing.

[13] AEMO, 5MS Dispatch Focus Group meeting pack 16 June 2019 and associated discussions. www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Five-Minute-Settlement

The alternative approach – setting LMPs based on losses to that point – would more closely approximate nodal pricing and would require changes to a larger number of systems and processes.

LMP cap and floor (identified, not resolved)

The proposal includes the potential for a variable cap and fixed floor on the locational marginal prices generators will be paid during periods of congestion, namely:

- Cap: LMPs cannot exceed the corresponding RRP in the region; and
- Floor: A floor set on LMPs to ensure generators do not face extremely low local prices.

Limiting locational signals in this way runs counter to what the Commission is aiming to achieve though the implementation of LMPs, that is clearer and stronger locational signals. The situation where an LMP consistently exceeds the region's RRP provides a compelling signal that additional investment is required in that location.

While the examples around looping effects provide context in respect to the complexity of the reform, they should not override the underlying rationale – that more granular locational pricing will produce better market outcomes.

Stanwell suggests that additional price caps and floors beyond the existing market price cap and floor are not required and do not reflect the Commission's principles of reform.

If additional cap and floor mechanisms were retained in the design, consideration of second order impacts such as the accumulated price cap should be considered.

Reduce disorderly bidding

The direction paper states that the main benefit of LMP is "*improving the efficiency of dispatch by removing incentives for 'race to the floor' bidding*"[14]. The direction paper also notes that:

> *"ROAM Consulting's forward-looking modelling estimated that removing race to the floor bidding could save $8.8 million (in NPV*

[14] AEMC, COGATI Directions Paper, p 63

terms) over the 18 years to 2030, with annual savings increasing to $3-6 million in the last five years of the period."[15]

Stanwell appreciates that any action that potentially passes unnecessary costs to consumers requires examination. In this instance, the forecast benefit of removing 'race to the floor' bidding is miniscule compared to the size of the NEM. This is consistent with the AEMC's Final Report into OFA Design and Testing:

> *"the available evidence suggests that these inefficiencies are small in magnitude. Indeed, the few quantitative estimates of these inefficiencies have grown smaller over the past few years.*[16]*"*

Despite this, the directions paper canvasses the possibility of conducting "*similar analysis, in order to obtain more up-to-date figures that take into account recent market developments.*" Stanwell expects that doing the same thing again will arrive at qualitatively the same outcome.

Even in the event that disorderly bidding is quantitatively modelled to increase significantly, from the limited detail in the directions paper of the proposed implementation of LMP, it does not appear the proposed reform will remove it but rather alter it in some circumstances[17].

The directions paper further seeks to link access to the efficient dispatch of generation, for example:

> *"Efficiency is promoted when prices reflect the marginal cost of the provision of a particular product or service, as well as any positive or negative externalities. At times of transmission congestion, the Commission considers that dynamic regional pricing should send the right incentives to generators in order to improve the prospect of the lowest cost combination of generation being dispatched"*[18]

A "marginal cost" approach to generation dispatch does not adequately account for the range of factors that informs generators' bidding strategies, such as the physical characteristics of each plant (e.g. minimum load, start-up costs, physical constraints) or fuel supply (e.g. availability, cost, conservation). Dispatch on this basis is inefficient, as detailed by Professor George Yarrow in his analysis of efficient bidding in an energy-only wholesale electricity market:

> *"Short-run efficiency can be achieved in energy-market designs provided that it is recognised that pricing should reflect economic costs, not incurred costs. Economic costs encompass scarcity rents as well as such things as expenditures on fuel used to generate electricity.*
>
> *…*
>
> *What would be problematic is if misguided regulatory policy required that bids reflected within-period, marginal, incurred costs or set an unduly low upper bound to prices.*[19]*"*

There is also the issue of dispatch efficiency being targeted by more than one ongoing market design change. In addition to COGATI, the AEMC is currently also progressing 5MS, which the AEMC determined:

> *"…would provide a better price signal for investment in fast response technologies, such as batteries, new gas peaking generation, and demand response. The alignment of the operational dispatch and financial settlement periods are expected to lead to more efficient bidding, operational decisions, and investment.*[20]

Given both 5MS and LMP aim to improve the efficiency of dispatch, the AEMC must demonstrate the marginal benefits of LMP for dispatch efficiency above those delivered by 5MS.

No new net risk to generators

The directions paper appears to downplay the significant change in risk faced by generators stemming from the proposed access reform, stating "*the introduction of dynamic regional pricing does not introduce a new net risk to generators*"[21].

The shift from volume risk to price risk is a sizeable change for generators, and the AEMC's analysis does not appear to consider which of volume risk and price

[15] AEMC, COGATI Directions Paper, p 40
[16] AEMC, Optional Firm Access, Design and Testing Final Report - Volume 1, p 102
[17] See Appendix 1
[18] AEMC, COGATI Directions Paper, p 24
[19] Yarrow & Decker, *Bidding in energy-only wholesale electricity markets*, Final-report, November 2014
[20] www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Five-Minute-Settlement/Program-Information-and-Fact-Sheets
[21] AEMC, COGATI Directions Paper, p 64

risk generators are best placed to manage, or the impact of this change for generators. This is particularly true if effectively different rules on market price and cap apply at the LMP and RRP.

Indeed, based on the limited examples provided it appears likely that generators will face both volume and price risk. Generators could be unhedged, notionally hedged but with low firmness or notionally hedged with high firmness. Each circumstance will provide different volume and price risks, even in the simplified examples provided.

Even in the event that volume risk under the existing access regime and price risk under the proposed access regime are commensurate, this does not mean all generators will face "no new net risk"; this only applies to generators who choose and are able to purchase transmission hedges. As detailed in the directions paper:

> *"…generators without transmission hedges would be subject to basis risk. In cases where transmission constraints bind, the local price would likely be less than the regional reference price. The basis risk in the model is not a new risk - it is a recasting of the existing volume risk that generators face from being constrained off in the current arrangements."*[22]

While the directions paper argues that the basis risk under transmission hedges is a recast of the current volume risk, and thus no new risk, this is not true for unhedged participants. There is a new net risk to unhedged participants as they would face both basis risk and price risk.

The proposed change in access regime will also increase the discrepancy between the short-run and long-run costs of generation.

Financial Risk Management

The directions paper outlines several key objectives for financial risk management:

- To improve investment certainty for prospective generators through both the connection process and increasing revenue certainty for generators, regardless of other generators' locational decisions; and
- To possibly reduce the cost of capital for generation investment in the long term.

Increasing certainty for generators

The directions paper proposes that transmission hedges:

> *"…should improve investment certainty for prospective generators and may reduce the cost of capital for generation investment in the longer term. This is because generators with a transmission hedge would no longer face the risk of other generators that might undermine their business case by locating nearby and causing congestion in the local transmission system."*[23]

Investment certainty is affected both by the initial business case of connection as well as revenue certainty. The directions paper overstates the increase in revenue certainty for generators and the design needs to consider potential aspects that may undermine investment certainty under the proposed reform.

Stanwell would be keen to see the AEMC's rationale on how the proposed access reform would reduce project finance costs in particular related to the issues discussed below.

<u>New project access to transmission hedges</u>

It is unclear how new projects would access transmission hedges. One of the live design issues discussed in the directions paper is whether the volume of transmission hedges generators can purchase is capped at the generator's capacity or unlimited. In the event the volume of transmission hedges generators are permitted to purchase is capped at generation capacity, will prospective projects be permitted to purchase hedges during the development of the business case and reaching Final Investment Decision (i.e. before a project is commissioned, it has 0 MW generation capacity)?

In making a determination on when prospective projects are permitted to purchase transmission hedges, the AEMC will need to take into consideration how some prospective projects undergo material changes in their generation capacity during development. AEMO's Generation Information shows the generation capacity of some recent projects have decreased as they have progressed from publicly announced to commissioning, for example Rugby Run

[22] AEMC, COGATI Directions Paper, p 66

[23] AEMC, COGATI Directions Paper, p 20

Solar Farm decreased from 150 MW to 65 MW; Lilyvale Solar Farm decreased from 150 MW to 100 MW and Susan River Solar Farm decreased from 100 MW to 75 MW.[24] In the event prospective projects are permitted to purchase transmission hedges before the ultimate generation capacity has been commissioned (or even before Final Investment Decision), processes will need to be in place to ensure potential projects do not "crowd-out" other investment in an area of the network by purchasing transmission hedges in excess of the generation capacity the project ultimately delivers.

This may face additional complication due to the lumpy nature of transmission investment, meaning that the unit price for one volume of hedges may not be valid for another similar volume.

Transmission hedges are not firm

Transmission hedges purchased by generators are not firm, which limits their ability to provide revenue certainty. If hedges are of a short-term duration, this does not provide revenue certainty over the life of the project. If the hedges are of a long-duration they will create a potentially significant increase in fixed costs while revenue (from generation and other services) remains variable.

Non-firm hedges do not guarantee a specified outcome in the same way a firm hedge does. They guarantee that the holder is entitled to a potentially variable portion of the difference between the variable LMP and the variable RRP during periods of congestion or system security constraints. If a transmission link is derated revenue is still at risk. If a transmission path is over-subscribed due to new entrants, revenue is still at risk.

Additional to hedging payments being able to be scaled back if settlement residue is insufficient, the proposed annual shortfall benchmark (i.e. the amount of shortfall costs that an efficient TNSP would be expected to incur) effectively fixes the firmness rate of transmission hedges if actual shortfalls are below the annual shortfall benchmark. Shortfalls beyond the allocated cap are borne by those generators holding transmission hedges.

One of the options presented for the incentive scheme for TNSPs to contain the shortfall costs is low-powered, providing transmission hedges less firm than they would be under a high-powered scheme.

[24] AEMO Generation Information Page, www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

Transparency of hedges

Under the proposed access regime the revenue provided by the transmission hedges is linked to:

- RRP (published)
- LMP (notionally available)
- Participation factors (notionally available)
- Hedge volume held by the generator (to be developed)
- Hedge volume held by other participants (to be developed)

The short term incentives presented to each participant depend on having all this information available in real time and pre-dispatch timeframes, both for the current situation and the constraints (if any) that would apply if the participant altered their behavior.

At this stage is it unclear the form the hedges are proposed to take and the method of publication of that information.

Tenor and supply of hedges

The directions paper states that transmission hedges:

> *"…would also create a clear and cost-reflective locational signal for new generation investment that is currently missing from the NEM."*[25]

While transmission hedges would provide a locational signal for market participants, initial stakeholder feedback indicates purchasers want longer-term hedges (as they provide a greater level of investor certainty). Longer transmission hedges would limit the frequency and timeliness of location signals transmission hedges provide.

LMPs will be published at a granular level every five minutes, so will provide considerably more pertinent locational information to market participants. The locational signals provided by transmission hedges should be considered as a supplement to the locational signals of LMPs rather than a key benefit of transmission hedges.

[25] AEMC, COGATI Directions Paper, p 22

However, as with locational signals provided by LMPs, Stanwell suggests that improving the scope and accuracy of currently-available locational signals and publishing currently unavailable locational signals would go a long way to address concerns about the locational decisions being made by new project proponents.

Lowering cost of capital

Transmission hedges will represent an additional fixed cost in the business case and this would increase the overall cost of the project.

Analysis of the firmness and benefit of transmission hedges would need to include the tradeoff between higher fixed costs and lower certainty in terms of both volume and tenor of hedges purchased.

Notably, new projects in uncongested locations may still need to incur significant cost to avoid a subsequent entrant derating the access to market that was originally present.

Transmission Planning and Operation

The discussion paper outlines the following objectives for transmission planning and operation:

- To enable generators to inform transmission planning (through the purchase of transmission hedges);
- Lower transmission costs and de-risk transmission investment for consumers; and
- To achieve a higher degree of co-optimisation of transmission and generation investment.

Generators to inform transmission planning

COGATI proposes that moving part of transmission planning and investment from network operators to generators will reduce costs to consumers.

Under the proposed reform:

> *"…transmission investment costs would no longer be recovered solely from consumers through TUOS charges. A portion of these costs would instead be collected from generators through the purchase of hedging products. This means that the TUOS component of a customer's bill should decrease."*[26]

While the *share* of total transmission costs recovered from consumers via the TUOS component of their bills will most likely decrease if the proposed access regime reform proceeds, it is unlikely that *total* transmission costs would decrease, and hence the total cost of energy paid by consumers increases.

Reasons total transmission costs and total energy costs to consumers could be expected to be higher under the proposed access regime reform include:

- **Transmission**
  - As natural, regulated monopolies, TNSPs typically have lower costs of capital than generators.
  - Additional generator margin on transmission costs: To ensure an economic return for generator's investment in the network, generators need to receive a rate of return on their transmission costs. These transmission costs also include the TNSP's rate of return.
  - Centralised planning: In the directions paper, "*AEMO and TasNetworks noted that all international power systems continue to rely on a high degree of centralised coordination and decision-making… due to the episodic and lumpy nature of transmission investment, the cumulative decisions of disparate commercial investors have not delivered optimal transmission investment.*"[27]
- **Wholesale**
  - Wholesale prices will increase: Under the proposed access regime reform, generator bids would include both energy and transmission network components, which is expected to result in higher wholesale costs.

Given these factors, the key question for Stanwell is how "the cumulative decisions of disparate commercial investors" will deliver optimal transmission investment at a lower cost than that the TNSPs would deliver under the current access regime.

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[26] AEMC, COGATI Directions Paper, p 21
[27] AEMC, COGATI Directions Paper, p 67

Some level of congestion is appropriate, as acknowledged by the proposed TNSPs' annual shortfall benchmark (to avoid incentivising TNSPs to "gold-plate" the network to the detriment of consumers).

Further, TNSPs planning and operating the network to two standards will also affect the size of the network and increase system costs for consumers. As detailed in the directions paper:

> *"…transmission network service providers would be required to plan their networks to meet both the reliability and access planning standards simultaneously."*[28]

The issue of the size of the transmission network increasing under transmission hedges and two transmission standards is not unique to COGATI. As discussed in Stanwell's January 2015 submission to the AEMC's OFA - Request for Comment:

> *"Under OFA, transmission companies must plan to build their network against two standards - the Firm Access Standard and the Reliability Standard. Generators will pay for network built through the firm access standard and the transmission company will pay for network built through the reliability standard. In both cases the customer ultimately pays for the entire network as both the generator (through the wholesale market) and the transmission company (through network charges) will attempt to pass these costs on to customers.*
>
> *With two planning standards, the transmission network will likely be larger than it would have been and customers will ultimately pay more. This is illustrated in the Venn diagram below.*[29]*"*

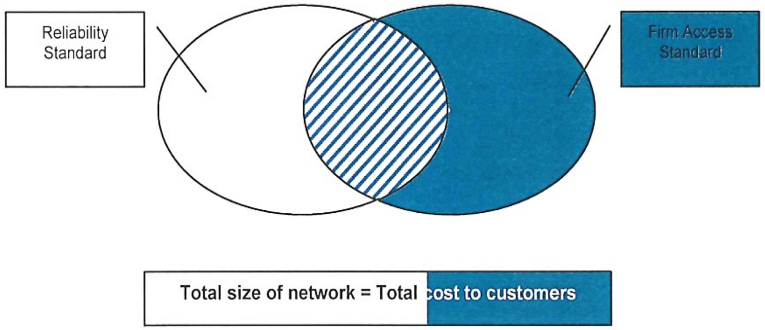

Figure 2 Likely transmission network planning

De-risking network investment

The directions paper suggests the proposed access regime reform will de-risk transmission network investment for consumers compared to the current access regime, stating:

> *"Consumers bear the majority of transmission investment risk in the current framework, so are shouldered with unnecessary costs if transmission lines become 'roads to nowhere'".*[30]

And:

> *"The new regime could also reduce the cost to consumers of inefficiently located, sized or timed transmission investment."*[31]

Such reduction seems unlikely as the current reliability standard – which underpins the decisions to build 'roads to nowhere' remains in force. An additional standard dedicated to building transmission infrastructure which is not required under the reliability standard appears destined to build more 'roads to nowhere good'.

The directions paper also states:

> *"Of course, inefficient investment decisions could arise in any access regime. However, under the current arrangements,*

[28] AEMC, COGATI Directions Paper, p 74

[29] www.aemc.gov.au/sites/default/files/content/2c54e461-eb3b-4c3b-a2fe-7bdbca6cb0c9/MarketReview-Submission-EPR0039-Stanwell-150130.pdf

[30] AEMC, COGATI Directions Paper, p (i)

[31] AEMC, COGATI Directions Paper, p 22

consumers, rather than market participants, bear much of the risk of transmission investment decisions being wrong."[32]

It is not clear how the proposed access regime changes will reduce the risk to consumers of paying for inefficient transmission network investment. Regardless of whether transmission costs are collected directly from consumers or are initially split between consumers and generators, they are ultimately borne by consumers. If the cost of investing in wholesale supply increases, the cost of wholesale supply would be expected to increase. Even where a generation investor makes such a poor decision to buy access that the business is unviable the TNSP will expect to recover the cost of the investment.

It is also unclear whether consumers would receive benefits or be exposed to costs in relation to any TNSP incentive scheme.

Stanwell notes that when TNSPs exceed the existing reliability standard consumers currently don't get a refund.

Neutrality

The directions paper does not adequately consider the treatment of generation and demand response from the distribution network. The discussion of Virtual Power Plants (VPPs) and demand response being largely co-located within load centres and thus, would have a LMP close to the RRP is valid only to a point given that more and more load centres are becoming occasional net generators. There has been no discussion about access frameworks for distributed generation. As demonstrated in South Australia, distributed generation can form a large part of the generation mix, and thereby transmission infrastructure.

Any access reform cannot be neutral or holistic if it does not consider all constituents equally.

Allocation and administration of transmission hedges

It is unclear where the roles and responsibilities for the allocation, pricing and administration of transmission hedges sit. While TNSPs are best placed to perform RiT-Ts and estimate the cost of network augmentation, in a rapidly evolving system pricing hedges based on long-term forecasts is highly speculative.

[32] AEMC, COGATI Directions Paper, p 15

There is no consideration given to the potential governance/licensing/accounting around the transmission hedge product. The product description "looks like" a derivative as it is financially settled against the spot price(s). It may also be considered a lease as it contains a fixed/minimum payment. It is unclear whether TNSPs or AEMO could (or should) be party to a derivative transaction. It is also unclear what impact a lease would have on the financing arrangements of potential new entrants.

TNSPs may also not be the right body to manage hedges given those hedges will also cover constraints due to system security reasons which generally can't be managed by the TNSPs. Similarly, any trading arrangements that may be established need to consider the ability of TNSPs to manage the associated risk.

Facilitating TNSPs selling transmission hedges would presumably require amendment of their statutory role and would require internal frameworks and processes. These would all have flow-on costs which would be borne by consumers.

Renewable Energy Zones (REZs)

The directions paper acknowledges that REZs are not the primary focus of COGATI:

> *"…the Commission considers that the issue of facilitating renewable energy zones is one of addressing coordination between generators and other generators. This is distinct from the broader objective of access reform, which is to facilitate more effective coordination between generators and the transmission sector."*[33]

While Stanwell acknowledges the role REZs can play in facilitating renewable energy integration and lowering system costs for consumers as the system transforms (e.g. sharing a synchronous condenser across a number of renewable energy projects instead of installing one per project, ensuring sufficient transmission capacity and transmission easement width to accommodate potential future projects), it is not clear how they fit into the access reform framework currently under consideration. The benefits identified appear to relate to connections and planning rather than access and settlement, and appear applicable only to radial or lightly meshed areas of the network.

[33] AEMC, COGATI Directions Paper, p 88

Further, there are other current market design processes aiming to support the development of REZs through transmission assets. Recommendation 11 of the ESB's Integrated System Plan: Action Plan states:

> *"That the ESB examine the possibility of a Fund to extend transmission assets to connect to Renewable Energy Zones with the cost of this transmission progressively recovered from consumers if and when utilisation increases. The required size of the finance, the source of funds, and how funds should be recovered and managed should be part of the examination."*[34]

Any actions intended to support REZs in the current access regime reform process will need to align with other processes to minimise disruption to the market.

34 www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/isp%20action%20plan.pdf

Appendix 1: Stanwell analysis of COGATI examples

While some detail of wholesale electricity pricing under LMP has been provided, it does not sufficiently explain how the proposed LMP will work. Explanation is limited to the examples provided in appendices B and C[35]. Appendix B provides concept level examples of five (5) potential conditions, summarised in Table 2.

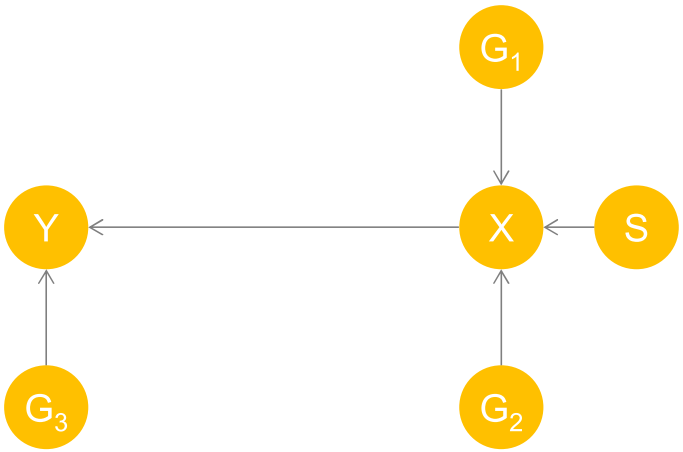

Figure 3 Configuration of generation, load and storage in examples in Appendix B

Scenario	Generation	Demand	Transmission	Transmission hedges (purchased)
1 – current arrangements	Generators G1 and G2 at location X; Generator G3 at location Y.	900 MW at Y	900 MW available from X to Y	N/A
2 – disorderly bidding			600 MW available from X to Y	N/A
3 – LMP				G1: 500 MW G2: 500 MW
4 – disorderly bidding	Generators G1, G2 and S1 at location X; Generator G3 at location Y.	900 MW at Y 300 MW scheduled load at X, nominally offline at RRP		G1: 500 MW G2: 500 MW S1: 0 MW
5 - LMP	Generators G1, G2 and S1 (offline) at location X; Generator G3 at location Y.	900 MW at Y 300 MW scheduled load at X, nominally online at LMP		G1: 500 MW G2: 500 MW S1: 0 MW

Table 2: Summary of examples in Appendix B

Under all scenarios, generation at node X faces potential limits in serving load at node Y due to the transmission link. In scenario 1 the link is rated at 900 MW (compared to 1,000 MW of generation at X) and in all other cases the link is rated at 600 MW (compared to 1,000 or 1,300 MW of generation). It is notable that the selection of 900 MW of load at Y and a 900 MW transmission rating means that price should be set by G_3 in all scenarios, since the next MW cannot come from a generator at location X. For the purposes of this analysis the load at Y is assumed to be 800 MW.

Note, while Stanwell's broad comments on transmission hedges are addressed in Section 4, transmission hedges are discussed here in the context of the examples provided by the AEMC.

Transmission hedge assumptions

Where transmission hedges exist they are noted as being "divided between generators 1 and 2 in proportion to their capacity". It appears that the battery/storage participant in the later examples does not purchase transmission

[35] AEMC, COGATI directions paper, pp 103-129

hedges as it receives no hedge payout under congestion conditions. Equally, the hedges purchased by G_1 and G_2 must equal or exceed the rating of the transmission line in the later scenarios as the storage device is not allocated a share of un-purchased transmission capacity.

- The examples should be explicit about how many transmission hedges each party has purchased.
- The examples should show how uncontracted transmission is allocated if less than 900 MW of transmission hedges are purchased.
- The examples should show how the transmission hedges are scaled back if more than 600 MW/900 MW of transmission hedges are purchased.
- The examples should show the TNSP compensation where transmission hedges are scaled back.

For the purposes of this analysis it is assumed that each generator has purchased transmission hedges in line with its installed capacity of 500 MW, although equal purchases as low as 300 MW are possible given the limited granularity of the examples.

Excluded concepts

The examples do not account for transmission losses or financial hedges. Each of these aspects is described as a potential benefit of the proposed access regime changes.

There is also no indication of compensation from the TNSP. The proposal to have transmission hedges non-firm with a weak TNSP incentive scheme (and potentially additional unforecastable cost if access is delivered on average above target) is likely to undermine the proposed financing benefit.

Transmission hedge costs are treated as fixed costs in the examples. This will exacerbate the difference between short-run marginal cost (SRMC) and long-run average cost (LRAC) analysis. Notably, most of the generators are going broke most of the time in the examples due to SRMC bidding (and LMP).

Scenario 1

Scenario 1 represents current arrangements with no constraints affecting dispatch and access arrangements appear irrelevant (other than the impact on long run costs which are not considered).

Scenarios 2 and 3

Scenario 2 sees the same conditions other than a derating of the link between X and Y to 600 MW which means that G3 is dispatched to meet demand at Y. Scenario 3 adds transmission hedges to scenario 2.

Immediately following the transmission derating G2 output is reduced (from 300 MW to 100 MW) despite the increase in reference price (from \$20/MWh to \$50/MWh). Under current access G2 rebids to the market price floor in response to the change in circumstances for one of a number of reasons:

- There is more spot market margin available by doing so (illustrated in the example);
- There is an increased and negative exposure to sold hedges (not illustrated);
- There is a revenue stream outside the spot market linked to generation volume (e.g. RET, not illustrated);
- Short run costs are not genuinely variable over the very short term (not illustrated).

Following the G2 rebid, G1 dispatch decreases and G1 rebids to the market price floor for the same reasons. Neither generator receives compensation from the TNSP for the effects of the derating although the TNSP may incur a cost under its existing incentive schemes (since the outage has affected price). All generators (G1, G2, G3) are exposed to the risk that the constraint relaxes and price falls to -\$1,000/MWh, potentially limiting the incentive to rebid to the floor.

The AEMC are concerned that the increase in resource cost associated with this rebidding will increase costs for consumers in the long term. The increase in costs is measured from the point after the constraint to the point after both rebids – the cost of the constraint is ignored.

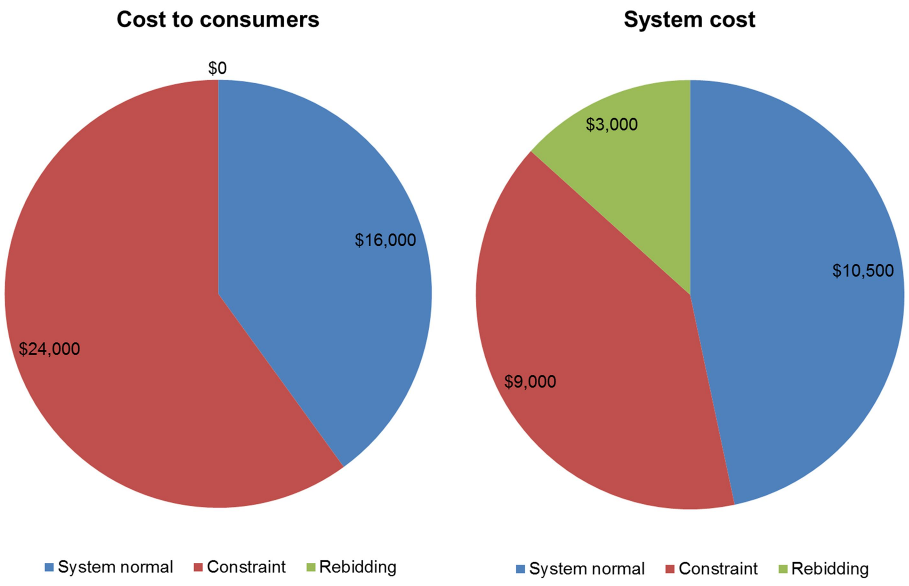

Figure 3: Cost to consumers and system cost

With the addition of transmission hedges the AEMC consider that the incentive for rebidding after the constraint occurs will be removed and resource costs will decrease (relative to the cost of the constraint AND rebidding).

Some things to consider:

- Assuming each of G1 and G2 have purchased transmission hedges equal to their capacity the TNSP will have charged them for a combined 1,000 MW of access. It has not provided the 1,000 MW either pre- or post- constraint, presumably because building additional capacity is considered inefficient given the presence and relative cost of G3.
    - Either the TNSP or consumers (via TUOS) will have benefitted from this charge for non-service in the first instance, however whenever demand at Y is between 900 MW and 1,000 MW the wholesale price will be inflated relative to a scenario where extra transmission is built.
    - There should also be a payment under the NSP incentive scheme as G1 and G2 have had their access "derated".
- Under the access pricing example each generator receives a different effective price for their generation, but are exposed to the same price under their financial contracts.
    - G1 receives $19,000 or $38/MWh for 500 MW: ((500*20 + 300*30)/500)
    - G2 receives $11,000 or $110/MWh for 100 MW: ((100*20 + 300*30)/100)
    - G3 receives $10,000 or $50/MWh for 200 MW: ((200*50 + 0*30)/200)
- Because G2 is "long transmission", if G2 were to bid some of its capacity below G1 such that G1 set the local price it would receive additional revenue:
    - G1 receives $15,500 or $38.75/MWh for 400 MW: ((400*5 + 300*45)/400)
    - G2 receives $14,500 or $72.50/MWh for 200 MW: ((200*5 + 300*45)/200)
    - G3 receives $10,000 or $50.00/MWh for 200 MW: ((200*50 + 0*45)/200)
    - Note: G2 maximises value by bidding down 101 MW so G1 is barely marginal and breaks even by bidding down 300 MW, which gives the same dispatch outcome as disorderly bidding.
    - G1 (being "short transmission") may then (depending on how much G2 has rebid) be incentivised to raise its offer price to just below G2 – bidding is arguably even less orderly.
- Bidding behaviour is also affected by the extent of the constraint as access is scaled dynamically. A shallower constraint (say 750 MW) creates a larger pool of funds to be distributed through transmission hedges, potentially strengthening the short/long incentives.
- The TNSP incentive scheme would similarly be expected to alter bidding incentives.
    - As this scheme has not been developed it is difficult to determine the impact.
- If G1 and G2 have purchased equal volumes of transmission hedges it indicates that they value the access to market equally despite their different short and long run costs. It is not necessarily true that the higher resource cost attributed to rebidding is inefficient as it only accounts for short run cost. There are examples of generation with lower short run and higher long run costs than their competitors (e.g. new solar vs legacy coal).

Scenarios 4 and 5

Scenario 4 adds a storage device at location X under current settlement arrangements and scenario 5 includes transmission hedges with the storage device in charging mode. The storage device does not appear to purchase transmission rights.

Some things to consider:

- The storage device (as a generator) locating at X appears to do nothing for reliability or price even under system normal conditions. G1 and G2 are lower cost generators and combined fill (over-fill) the transmission link.
- The storage device (as a load) locating at X appears likely to be over-sized except under de-rated transmission conditions. It is not clear how it will discharge profitably and so it is not clear why the system cost incurred to charge it is efficient.
- The resource cost indicated in example 5 is incorrect – the correct total of $25,500 is only marginally lower than in the congestion example. Unless that storage can discharge at a later time to lower the system resource cost this appears to be wasteful. As noted above the storage device appears to be charging with no potential to generate profitably at a later time.
- If an alternative storage specification was included – say one which charged off G1 pricing ($5/MWh) and discharged at $10/MWh then running G2 would actually be disorderly (assuming the storage device was charged).
- If the storage device purchased transmission hedges it is unclear what would occur.
    - The long run cost of the storage device would increase.
    - If the TNSP did not increase the actual transmission link then G1 and G2 access would decrease due to the presence of a new entrant. This is in direct opposition to the stated intent of the reform. Consumers may be charged less TUOS, depending on the TNSP incentive scheme.
    - If the TNSP did increase the actual transmission link (1:1 for 300 MW of additional access) consumer TUOS would remain the same (assuming pricing is accurate) and G1/G2 access would fractionally improve (from 500*900/1000 to 500*1200/1300).
    - If the TNSP increased the actual transmission link by an amount other than the additional access, transmission hedge firmness may further improve or degenerate. TUOS may increase or decrease.

Overall, the examples highlight at least as many unresolved issues as they set out to explain.

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