AEMC

REVIEW

Australian Energy Market Commission

UPDATE PAPER

TRANSMISSION ACCESS REFORM

26 MARCH 2020

INQUIRIES

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Reference: EPR0073

CITATION

AEMC, Transmission access reform, 26 March 2020

ABOUT THE AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

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1 INTRODUCTION

The *Coordination of Generation and Transmission Investment* (COGATI) review is focussed on examining *when* the transmission access framework will need to change, and, if so, *what* it will need to change to.

This review is in response to terms of reference received in 2016 from the Council of Australian Governments (COAG) Energy Council. The Council asked the Australian Energy Market Commission (the Commission or AEMC) to implement a biennial reporting regime on these matters.[1]

The inaugural COGATI review (final report published in December 2018), concluded that transmission frameworks need to change so that our regulatory frameworks can keep pace with the transition currently underway in the NEM. The second COGATI review - the subject of this update - outlines the path forward to a transmission access regime that integrates new technologies into the national grid in way that is reliable, secure and works in consumers' best interests.

This report outlines a two-part solution to improving transmission frameworks and supporting the ongoing transition to a lower emissions electricity sector. It is a fundamental part of any future market design and will be further developed and refined over the coming year by the AEMC, through the Energy Security Board's (ESB's) existing processes for market design.

The first part of the solution is to improve **transmission planning and investment decision-making processes** by actioning the ISP. These actions are being led by the Energy Security Board.

The second and equally important part of the solution is to reform **transmission access arrangements** - the subject of this paper. The AEMC will continue to develop a transmission access model as a key component of the ESB's market design work over the course of 2020. The reforms relating to the two-sided market, ahead markets and the COGATI access and charging reform are measures that need to be in place before 2025 to support increased variable renewable energy and the integration of distributed energy resources (DER).

A cohesive package of draft rules encompassing access reform will be delivered as part of this process. This package will refine the blueprint design developed to-date, incorporating stakeholder feedback. This blueprint is outlined in the accompanying technical specification document.

We have conducted extensive stakeholder engagement as part of this review. We have considered 151 written submissions from 67 different stakeholders on four consultation papers; held six technical working group meetings; and two public workshops. We have also held more than 130 bilateral meetings and workshops with the ESB, AER, AEMO, consumers, TNSPs, incumbent and prospective generators, existing and prospective investors, government departments and other interested parties. We have given all of this feedback

1 The terms of reference were provided under section 41 of the National Electricity Law (NEL) and can be found here: https://www.aemc.gov.au/sites/default/files/content/97164a7bf-49fb-9f2e-f6b996f5a96b/Reporting-on-drivers-of-change-Terms-of-Reference.PDF

careful consideration and have taken it into account when developing this integral part of the solution to Australia taking the cheapest, fastest and fairest path to a low emissions energy future.

2 A TWO-PART REFORM TO TRANSMISSION FRAMEWORKS

A two-part solution to re-purpose transmission frameworks for the future has been developed in conjunction with the ESB and the other market bodies.

2.1 Improvements to transmission planning and investment

First, near-term improvements should be made to the **transmission planning and investment decision-making processes**, executed through rules to action the Integrated System Plan (ISP)[2] and near-term actions to progress renewable energy zones. These actions are being led by the Energy Security Board.

The ISP outlines the need for investment in new transmission infrastructure to contribute to reliability and security for consumers, to relieve constraints and ultimately, reduce prices. Rules to action the ISP will facilitate transmission infrastructure by streamlining the regulatory processes for key identified projects. They will also retain a rigorous cost benefit assessment, to protect consumers from the cost of excessive transmission infrastructure development. This process should shorten the gap between the timing of new generation investment and the transmission infrastructure required to serve it. As a result, this should help to alleviate current high levels of congestion. A final set of rules is expected to be provided to the COAG Energy Council for approval at its meeting on 20 March 2020.

In addition to the actioned ISP rule change, the ESB has been tasked by the COAG Energy Council to provide interim advice by March 2020 on options to implement renewable energy zones (REZs), amongst other things.[3] The Commission's prior work on renewable energy zones is feeding into this ESB work. Any recommendations from the ESB's work are intended to facilitate the near-term development of REZs (including the transmission infrastructure). REZ development will lead to better coordination and efficient expansion of the grid by taking advantage of economies of scale to allow more renewable generation to be connected.

2.2 Improvements to transmission access arrangements

Second, **transmission access arrangements** also need reform to make sure the transmission infrastructure built through the processes outlined above is used effectively, and provides signals and information to aid long-term planning and future generation and transmission investment decisions. In other words, it is designed to make sure that generation, storage and transmission investment is coordinated, efficient, and delivered at least cost to consumers.

The improvements to the transmission access process has been the focus of this review.

2 As well as resultant changes to the transmission planning and investment decision-making processes.

3 See: http://www.coagenergycouncil.gov.au/publications/immediate-reliability-and-security-measures

The current arrangements do not incentivise generators and storage facilities to locate and operate in a way most likely to minimise costs for consumers. This makes it more difficult to keep power prices trending down. That is why, in terms of a long-term solution, access reform and transmission planning are equally important. If transmission planning is implemented on its own, this will defer, rather than solve the problem of a build-up of congestion and inefficiency. If transmission planning and access reform are implemented together, the financial investment in transmission planning will keep its value into the future.

Changing transmission access arrangements - by implementing locational marginal pricing and financial transmission rights - is a key pillar of any future market design. Locational marginal pricing and financial transmission rights will complement and in some cases enhance and enable options being considered by the ESB in its market design work program. For example, access reforms are an important component for the most effective operation of two-sided and ahead markets.

Evidence from overseas markets where these reforms have already been implemented, or will shortly be implemented, demonstrate they are flexible and can accommodate a variety of different market structures and designs. For example, FTR/LMP regimes exist in markets that have centralised capacity mechanisms, and those that do not.

Continuing to develop and design in detail these access reforms and the system changes that will support them needs to take place in lock step with the future market design. This will make sure that the design is a holistic package with the best chance of success. For example, a decision made in the ESB's market design process may result in system changes to the NEM dispatch engine, which may then make implementing a particular design decision within the access model less expensive to implement (such as the introduction of volume weighted average pricing for those market participants facing the regional price).

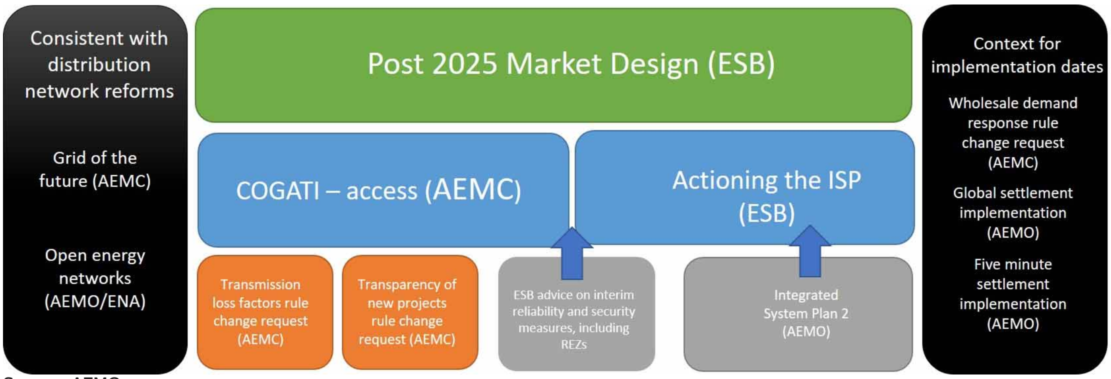
The proposed transmission access model represents a significant change to the existing market design. It will take a number of years to fully develop and implement in a way that allows market participants to adjust to the change. It is therefore appropriate that these changes are implemented in a way that is consistent with the timetable of the ESB's market design program. We recognised this in revising the implementation timeframes in our December 2019 update paper. Nevertheless, now is the time to agree on how access will look in the future. It is important to work out what the arrangements for the reform are as soon as practicable to provide greater near-term certainty to the market.

In contrast, changing transmission planning processes and mechanisms to facilitate renewable energy zone development can be made relatively quickly. This will help realise the benefits from more streamlined transmission build faster.

A two-step solution is foundational to transitioning our national electricity market because it both addresses current challenges and prevents us from having to face these same challenges in the future. Expediting transmission investment addresses the most immediate congestion and losses issues as quickly as possible by facilitating efficient transmission investment, while access reforms will deliver an enduring and complete solution through wider market reform.

There are a number of other reforms underway which support the actions to expedite transmission investment and access reforms set out above.

Figure 2.1: Interaction with other key reforms



Source: AEMC

These other reforms are necessary, but not sufficient on their own, without reforms to the access arrangements. For example:

- The AEMC's recent rule to improve the transparency of new projects coming to the system will improve the ability of generators and investors to understand where different prospective players are going to locate. However, while it is helpful to have more information, understanding where parties are locating does not change the fact that the underlying financial incentives that generators and storage units face under current arrangements do not match the needs of the system.
- The implementation of five minute settlement, along with global settlement, changes bidding incentives for generators to bid into dispatch over time. But they do not change incentives for race-to-the-floor bidding behaviour which are driven by locational differences. Five minute settlement and global settlement are different solutions to different, but analogous, problems.
- The integration of renewables, batteries and distributed energy resources is needed at both the large- and small-scale ends of the grid. The principles that apply to connection and access of distributed energy resources are the same as those that apply to the connection and access for large-scale parties. Proposals to change access at the distribution level were recently proposed in the Electricity Network Regulation Framework Review ('grid of the future'), which forms part of the ESB's work on DER. The issues that access reform addresses at the transmission level are also being replicated at the distribution level. Both reforms are being approached consistently. However, large-scale generators and distributed energy resources have different access needs that must be considered and managed.

3 THE NEED FOR CHANGE

3.1 A changing electricity system

The electricity sector is currently undergoing a significant transition. Generation roughly equal to the current size of the NEM (50 GW) is foreshadowed for connection to the grid over the next 10 years, with the NEM replacing most of its current generation stock by 2040.

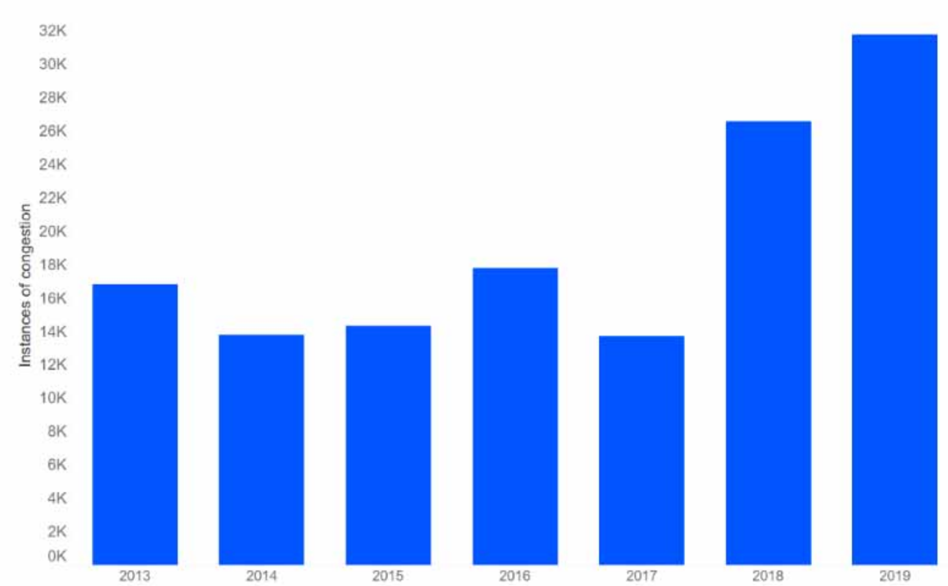
Unlike the existing power system, the system of the future is likely to be characterised by many relatively small and geographically dispersed generators. To date, many newer generators have located in areas where there is not enough existing transmission to serve them. Instead, because they are mostly solar and wind technology, they have connected to the network in sunny and windy areas with insufficient network capacity. This means substantial transmission investment is now needed to accommodate them. Also, new types of generation can be built more quickly than the transmission infrastructure required to serve them and this pace of change has made the need for action more acute.

"Congestion" is what happens when there is a bottleneck somewhere on the network. That is, when electricity being carried across elements or sections of the network reaches a technical limit. It is well-established that removing congestion completely would be inefficient because building the transmission needed to do so would be extremely costly.

When congestion occurs, demand must still be met, and so the additional electricity must come along an alternative route from an alternative and more expensive source of supply. Congestion is extremely common with many thousands of instances of congestion (i.e., the number of individual elements or sections of the network that are congested in any five-minute period) every year.

But the level of congestion has increased substantially in recent years, particularly in North Queensland, South West New South Wales and North West Victoria, driven by the changing nature of the power system described above. Figure 3.1 below shows that congestion has roughly doubled from a relatively stable level before 2018.

Figure 3.1: Instances of congestion across the NEM



Source: AEMC analysis

Projections show that these trends are set to continue. Both the Australian Electricity Market Operator (AEMO) and transmission network service providers (TNSPs) through their planning processes are forecasting significant increases in congestion across the entire network, driven by the substantial levels of investment in generation.[4]

In addition, there are also significant changes in marginal loss factors from year to year that are creating uncertainty and changing revenue expectations for generators. These are being driven by the significant amount of generation connecting to the network, typically towards the edges of the grid.

Stakeholders of all types (generators, investors, market bodies, networks, governments) agree that poorly coordinated generation and transmission infrastructure investment and the ability to manage risk arising from congestion and losses are creating material problems.[5] They also agree that existing arrangements are not fit-for-purpose, and change is required, although not all stakeholders agree on the diagnosis of the specific problem in the market design, nor the appropriate solution.

The majority of consumer groups, the Australian Energy Regulator, the ESB, the Australian Competition and Consumer Commission and transmission network service providers, along

4 Sources include: AEMO, Draft 2020 Integrated System Plan, 12 December 2019, p. 50; TransGrid, New South Wales Transmission Annual Planning Report, 2019, p. 7.

5 See for example: Clean Energy Council, submission to the directions paper, p. 1; John Laing (Clean Energy Investor Group), submission to the directions paper, p. 2; AER, submission to the discussion paper, p. 1; Energy Networks Australia, submission to the discussion paper, p. 3; ACCC, submission to the discussion paper, p. 1; Government of South Australia, submission to the discussion paper, p. 1.

with a subset of generators and investors, support the proposed access model in principle, for the reasons outlined through this report.

In contrast, other investors and generators are not supportive of the access model, citing a variety of reasons that differ across the stakeholder group. Often they relate to the cost and complexity of the reforms, concerns that the reforms could increase rather than decrease risk, concerns that the access reforms are not well coordinated with wider market reforms being considered by the ESB and concerns that the materiality of the problems, and the benefits of the reforms, have not been quantified.

In our extensive stakeholder engagement we have been:

- working with stakeholders to help them better understand the reforms
- undertaking modelling to inform the case for change, as well as policy design decisions, with this discussed more in the next steps section below
- working through changes to the design in order to address stakeholder concerns, for example, we have:
  - taken steps to better enable market participants to manage risk by making FTRs firmer (i.e. more likely to pay out in all circumstances) and longer in tenure
  - extended the proposed implementation date to better coordinate and integrate with other reforms being considered as part of the ESB's work.

3.2 Limitations of the current transmission regime

When constraints arise on the transmission network, the underlying value to consumers and impact on emission reductions of an additional unit of electricity differs from location to location. Without building more transmission capacity, which takes time and costs money, the amount of electricity flowing out of the congested area cannot increase due the limit being reached on the element or network section. Therefore, the value of electricity in congested parts of the network is typically relatively low: any additional generation can only offset the most expensive generator which is also in the congested area.

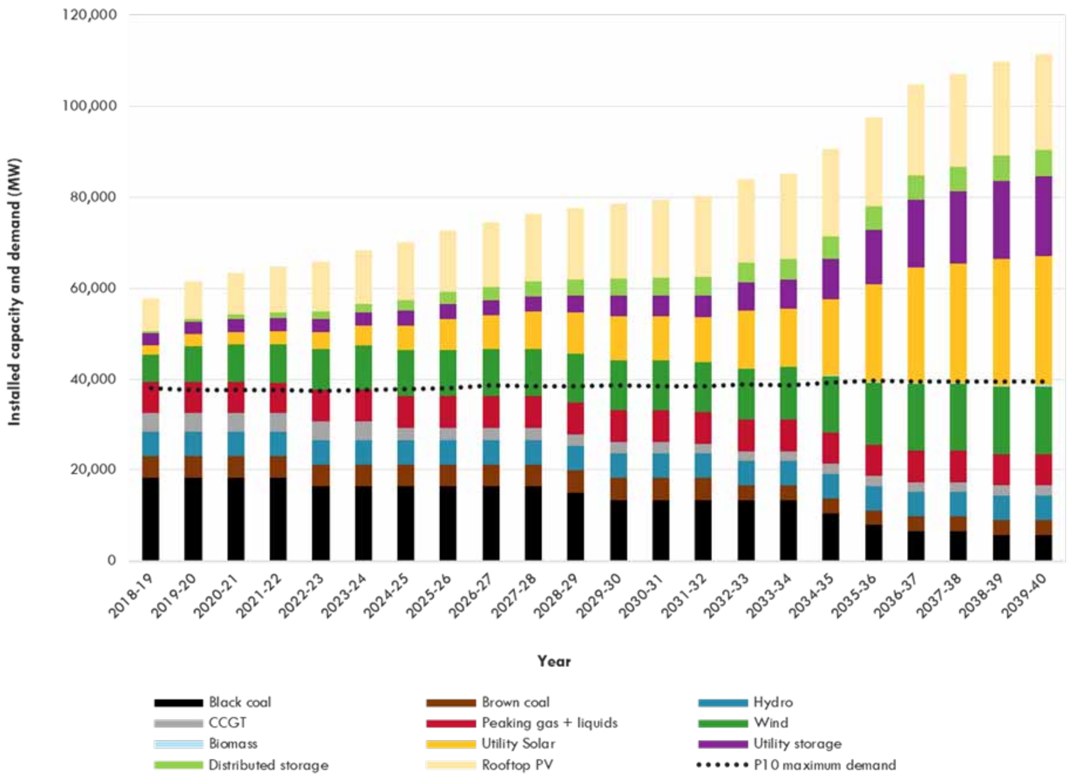
In some congested areas and at some times, all the generators that are operating may be variable renewable generators, so the incremental value and emission reduction of additional variable renewable generation is close to zero: the next renewable generator simply reduces the output of the existing renewable generators. In contrast, additional renewable generation in an uncongested area will offset the most expensive generator anywhere and so be of higher value. It will likely also have a greater impact on emission reductions.

Despite the differences in the value of electricity between locations when there is congestion, under the current transmission access regime, all generators and storage within a region face the same price (adjusted to account for the effect of losses as electricity is transported across the network) for every unit of electricity provided to (and consumed from, in the case of storage) the system. That is, all generators access the regional price for their physical dispatch, regardless of their location within the region.

The current transmission access regime was a design choice that was an acceptable compromise between reflecting the underlying realities of the system and the benefits of a seemingly simple unified price model. In the past, relatively low levels of congestion meant that inaccuracies in the price signals under a regional pricing regime were reasonably modest. In other words, the difference between the price and the value of electricity was relatively small. Further, relatively low levels of generation, storage and transmission investment meant that the inefficiencies in investment arising from these inaccuracies were also reasonably modest.

However, this is no longer the case. For example, see the Australian Energy Market Operator's (AEMO's) estimations of the future generation mix, set out below. This show that the scale of new generation connecting to the system by 2040 is significant.

Figure 3.2: Expected future change in generation mix and demand



Source: AEMO, 2018 ISP Generation and Transmission Outlooks database, neutral scenario

The transmission access arrangements are now a significant problem for the current power system, where there is increased generation investment occurring in parts of the power system which are currently poorly placed to accommodate them. And they will be a significant problem for the future power system if preventative measures are not taken. Without access reform, levels of congestion will continue to rise and increased transmission investment will again be required to alleviate that congestion. In these future circumstances, the inaccuracies arising from the regional pricing regime will increase. The result will continue to be poorly coordinated transmission and generation investment, increasing prices for consumers, higher emissions than would otherwise occur and greater risks for market participants.

While the current arrangements provide some locational signals, these are incomplete and so do not adequately incentivise new generators and storage systems to make the best use of existing and new transmission capacity. Instead, current arrangements are a disincentive to locate and operate in a way that minimises total system costs (i.e. generation *and* storage *and* transmission). This is because the current arrangements don't provide information or signals about how transmission capacity should effectively be used. Also, the current framework doesn't provide risk management tools for generators and storage to use as part of their investment or operational considerations.

Improving the transmission access regime will therefore see the underlying value of electricity reflected in the price that is paid for it. Existing arrangements will make it more difficult to keep power prices trending down and the NEM will not realise the full emissions value of the current transition to renewable generation that is occurring.

4 THE ACCESS MODEL

The current arrangements result in a disconnect between the *value* and *price* of electricity at a particular location and time when there is congestion on the transmission network. The proposed access model better reflects the value of electricity in the price seen by market participants at a specific location.

Access reform works hand in hand with near term augmentation of the transmission network and improvements to the transmission planning processes through the actioned ISP rules and the near-term REZ reforms being developed and implemented by the ESB. Improvements to transmission planning and investment processes will streamline the regulatory processes to deliver more timely, and appropriately sized and located, transmission investment, while the access reforms provide price signals to generators and storage to better utilise the existing and expanded transmission network. Combined, access reform and improvements to transmission planning and investment processes provide an enduring solution that would lower prices for consumers, risks for market participants, and emissions. The access model is summarised below.

4.1 The proposed model

The proposed access model involves two key changes to the current arrangements, in order to better reflect the underlying value of electricity in the price, and enable market participants to better manage risk. These two changes are **locational marginal pricing** (LMP) and **financial transmission rights** (FTRs).

Beyond adopting these two core features of LMPs and FTRs, detailed decisions are needed on specific design considerations. To advance this process, the Commission has developed a blueprint access model. A detailed discussion of the current status of the blueprint, its rationale, alternative design decisions, and stakeholder views on these, is provided in an accompanying technical specification document.

1. Locational marginal pricing

Large-scale generators and storage would receive a spot price that would vary with their location (**locational marginal pricing or 'LMP'**). Retailers, and so ultimately customers, would continue to pay the regional reference price, which would promote contract market liquidity.

Under locational marginal pricing, electricity supply (generation) is priced based on *local* supply and demand conditions. While this is a significant change to the existing NEM design, it is not a radical concept: it is in keeping with our everyday experience of prices for other goods and services varying based on local supply and demand.

When conditions vary between locations in the national electricity market, for example due to constraints on the flow of electricity, locational marginal prices also vary across the network.

These arrangements will not increase the market's complexity, but rather, make the physical complexity of the system, which is likely to increase over time, more transparent.

A locational marginal price would more accurately reflect the value of supplying electricity at each location on the network. Compared to the existing arrangements, this will result in more efficient and coordinated generation, storage and transmission investment.

2. Financial transmission rights

Participants would be able to purchase **financial transmission rights** (**FTRs**) which pay out on the differences in wholesale market prices that arise due to congestion and losses. On a transitional basis, some FTRs would be allocated ('grandfathered') for free. This will mitigate the financial impact of sudden changes in the market and provide time for adjustment.

FTRs would give market participants the tools to better manage existing (and deteriorating) transmission congestion and loss-related risks, which, in turn, will provide more revenue certainty and the confidence to invest.

Locational marginal pricing means that generators are paid and consumers pay a different amount for the same electricity in the presence of congestion and losses. This results in more money being paid into AEMO's settlement system than out of settlement, and therefore, there is excess money left over.[6] The money to fund the FTR payouts comes, primarily, from this excess money.

Market participants would compete to purchase FTRs through an auction run by AEMO. The revenue received from the sale of FTRs would be used to increase the firmness of the FTRs if necessary, but primarily to offset transmission charges that consumers pay.

4.2 Overseas experience

Changing the existing regional pricing model represents a significant change to the NEM design. But, LMP and FTR markets are common and well-established overseas in a variety of different settings. Their past success has seen them being progressively implemented overseas.

New Zealand's market design has featured locational marginal pricing since it began in 1996. Locational marginal prices and financial transmission rights are a major part of the US Federal Energy Regulatory Commission (FERC's) standard market design template, having been progressively adopted in all seven US-organised electricity markets starting with PJM in 1998. In 2002, FERC noted that:[7]

> LMP – should encourage short-term efficiency in the provision of wholesale energy and long-term efficiency by locating generation, demand response and/or transmission at the proper locations and times.

The underlying rationale for the implementation of LMPs and FTRs in other markets are the same as those outlined above: a desire to provide appropriate, location specific price signals for market participants, and the tools to allow them to manage transmission risks.

6 This money is usually known as "settlement residue".

7 Federal Energy Regulatory Commission, Federal Energy Regulatory Commission Working Paper on Standardized Transmission Service and Wholesale Electric Market Design, March 2002, p. 6.

Similar reforms are currently being undertaken in Ontario, Canada as part of Market Renewal reforms in that country. These reforms are designed to transition that market towards a renewables future.[8] They have scheduled go-live date of March 2023.[9] IESO as the market operator for the Ontario market stated that "LMP is a foundational feature" of their reforms, and that locational prices will "reduce the cost of energy for Ontario consumers".[10]

The evidence from these overseas markets is clear. Locational marginal pricing and financial transmission rights are a common, well-established transmission access model, viable in a variety of different market designs and structures, and well-suited to enable new generation into the power system and managing the ongoing transition to a low-emissions sector.

4.3 A blueprint for LMP and FTRs for the NEM

The Commission has developed a blueprint for the access model, which provides further details about how the two core features of locational marginal pricing and financial transmission rights might be designed for the NEM. This is outlined in an accompanying document.

This blueprint takes into account the specific features of the NEM - its size, geography, network topology, market structure and other elements of the broader market design. The design will continue to evolve over the course of 2020 as the Commission continues to engage with stakeholders, and does further specification work along with the ESB's market design work. It is important for this work to be integrated, since other reforms being pursued will likely change the costs and benefits of specific design decisions within the access model. For example, if the ESB's market design work results in system changes to the NEM's dispatch engine, then costs of moving to dynamic losses, which also require changes to the NEM dispatch engine, will be lower.

As noted above, it is important to fully develop the detailed access model as soon as possible. This is in part driven by stakeholder feedback that the potential prospect of the reform is creating uncertainty in the industry.

The blueprint has already evolved over the course of the current review to reflect stakeholder feedback - most notably to make the FTRs firmer and therefore more useful to market participants (i.e., more likely to pay out in all circumstances) and longer in tenure. Improving the FTRs design is intended to address stakeholder concerns that the reforms will increase risks for market participants, reduce contract market liquidity, and stifle investment.

The blueprint also proposes a transition period, consistent with the implementation timetable of reforms underway, including the other ESB work, to allow for the market to learn and adapt.

8 See: http://www.ieso.ca/en/Learn/Ontario-Power-System/Electricity-Market-of-Tomorrow

9 IESO, Market Renewal Program, Energy Stream Business Case, 22 October 2019, p. 46.

10 IESO, "Education and Awareness - Energy Workstream High-Level Designs - Variable Generators", December 2018, p. 25.

5 BENEFITS OF ACCESS REFORM

The proposed access reform will reduce prices for consumers, reduce risk for market participants and enable a lower cost integration of renewables into the system, thereby reducing emissions.

The introduction of locational marginal pricing and financial transmission rights simultaneously addresses three problems inherent in the current regional pricing regime.

Solving problem 1: Aligning location decisions with physical needs of the system

By pricing energy at the efficient locational marginal price, rather than the regional price, market participants are provided incentives to invest in, and operate, assets in a way that meets the physical needs of the whole power system. In turn, this is expected to reduce costs, and ultimately consumer bills, as well as emissions.

NERA Economic Consulting has been engaged to review the evidence available on the costs and benefits of similar reforms implemented in other jurisdictions and provide an estimate of the expected costs and benefits of this reform, based on the evidence from comparator markets.

NERA have found that the *operational benefits alone* of introducing locational marginal pricing and financial transmission rights based on these benchmarks (range of $30 million to $137 million *per year*) exceeds the latest available estimate of implementation costs (a *one-off* cost of $149 million for Ontario), on a net present value basis. This suggests the payback period could be less than 2 years.

Using benchmarks NERA has also estimated a further $327m to $690m per year that could be saved through more efficient siting decisions by generators. It notes that this range may be overstated due to specific differences between the comparator study (New York) and the NEM.

In turn, improved locational decisions by generators and storage might delay or avoid transmission infrastructure upgrades that would otherwise have been required under the existing regime. This can reduce total system costs, lower consumer prices and result in improved information for the transmission planning process.

Solving problem 2: Helping generators manage risk

Market participants are better able to manage the risk of congestion and losses by acquiring FTRs. When congestion and losses occur, this creates price differences across the network. FTRs payout on these price differences and so mitigate against the financial impact of the congestion and losses. This will allow market participants to have more revenue certainty and the confidence to invest and operate effectively. A market participant can protect themselves from the financial implications of another subsequent generator connecting beside them and reducing their physical output or changing losses.

These arrangements also allow market participants to enter into financial derivative contracts with more confidence, because their revenue to back these contracts is less affected by the impact of physical transmission congestion or changes in losses. These effects should ultimately reduce prices for consumers.

This contrasts with the current arrangements where, if congestion is greater than expected (for example, because an additional generator unexpectedly connects to that part of the network) and incumbent generators are constrained down, their output (and so their revenue) is decreased. Similarly, if losses are different than expected, a generator's revenues are impacted.

A number of stakeholders, particularly some generators and investors, have disputed this benefit – arguing instead that the reforms would increase risk, and hence decrease contract market liquidity and stifle investment – ultimately increasing cost to consumers.

In part, this concern was driven by the short length and possible lack of firmness of the FTRs. To address this concern, the blueprint design has been adjusted to make the FTRs more useful to market participants. Modelling will also be undertaken to ascertain more detail as to how 'firm' these FTRs may be. The implementation date has also been delayed in part so that stakeholders will have more time to understand and adapt to the new regime.

NERA has been asked to provide its views on this benefit. Its initial analysis suggests no material impact on cost of equity as a result of access reform, and that a generator's cost of debt could reduce by up to 30 to 50 basis points if the proposed reform is highly successful. NERA also expects no material change in the cost of capital as a result of regulatory risk.

Solving problem 3: Ensuring energy, in the presence of congestion, is paid its fair value by the market and consumers

The regional price is typically higher than local marginal prices in the presence of congestion, meaning that under the current regional pricing regime, in the presence of congestion generators typically receive additional money compared to if they were paid the local marginal price.

It is in the long-term interest of consumers that they, and not generators, receive this money. The efficient price for generators to receive is the locational marginal price, so receipt of a price above and beyond this imposes higher costs on consumers.

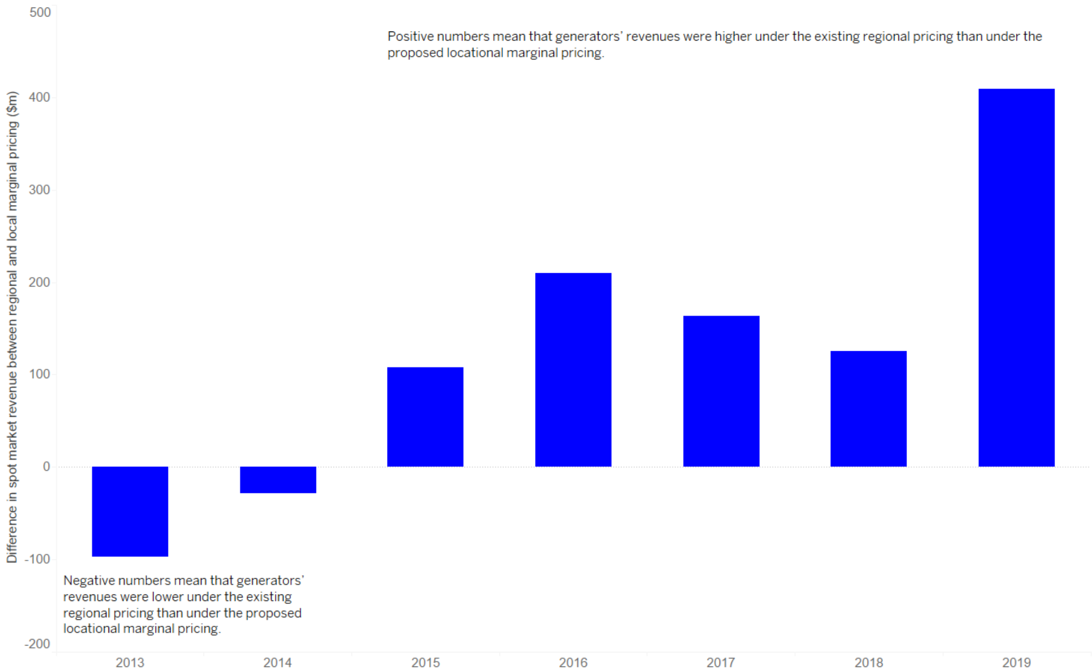
Under the access reforms, generators will have to pay for FTRs to access this money, with the proceeds from the sale of the FTRs being used to enhance the firmness of the FTRs and then offset consumer's bills.

Calculating how much consumers' bills will be offset by this effect is challenging. While locational marginal prices have been calculated by the dispatch engine since the start of the market (although not used for settlement), and can be compared to the regional price to estimate the size of the offset, investment and bidding behaviour will change as a result of pricing at the locational marginal price. As such, the historically calculated locational marginal price is unlikely to be an accurate reflection of what would have happened with access reform in place.

Furthermore, it is unlikely that the revenue from the sale of FTRs will exactly match additional money that generators currently receive by being settled at the regional rather than local marginal price. Most generators' revenue is driven by financial market derivatives and PPAs that they have entered into.

Noting these limitations, we have estimated the historic differences in the total revenue for generators through the spot market had the generators been settled at their local marginal price (as calculated historically) instead of the regional price. The results are provided in figure 5.1 below.

Figure 5.1: Difference in spot market revenue between regional pricing and LMP



Source: AEMC

Noting limitations with the methodology used to calculate what would have otherwise happened, the estimated difference in the revenues under the two pricing regimes increased dramatically between 2018 and 2019, from $125m to $409m, consistent with the fact that the level of congestion on the transmission network is increasing. The difference calculated for 2019 is approximately 2.3 per cent of the total wholesale spot market revenue, or $2.2/MWh.

The detailed market modelling of the NEM, being undertaken in 2020, should provide a more accurate estimate of the likely benefit to consumers of receiving money from the sale of FTRs, which is currently implicitly allocated to market participants.

As noted throughout this review, access reform will create winners and losers. The main winners are consumers, through better sited generation, lower transmission capital costs, lower generation fuel costs, and through the offsetting of transmission charges. Through its benchmarking analysis, NERA's best estimate of the total benefits for consumers of the reforms is $387m per year.

Among the losers are likely to be those generators who are located behind constraints and currently receive a regional price which is higher than locational marginal price. Their new level of profitability will be more consistent with the value that the generators are adding to the system (because the locational marginal price represents the marginal value of generation at that location at that time). But grandfathering arrangements will be required in order to manage sudden change in profitability that might otherwise occur, given the sunk investments made under the existing arrangements.

Investment in new transmission will also alleviate constraints and hence reduce the impact of the change to LMP on the price generators face. However, as noted above, investing to alleviate all constraints would be extremely expensive and would be neither an efficient nor enduring solution to the market problems with the current access regime.

6 NEXT STEPS

A blueprint for access reform, representing the current design, has been outlined in the accompanying technical specification document.

We will continue to refine and further develop the blueprint of the access model with stakeholders over the course of 2020, in order to develop draft rule changes that can be considered as part of the ESB's proposed reforms. This will allow access reform to be fully integrated and coordinated with other reforms being considered.

In addition, and consistent with stakeholder views, we will continue to undertake quantitative modelling of the reforms. These will inform both specific design details (e.g. firmness of FTRs; market power considerations) as well as the costs and benefits of the reforms in general. This will involve explicit market modelling of the NEM in order to quantify these impacts in an investment and operational sense. We have engaged NERA Economic Consulting for this task and will undertake it in a transparent and consultative manner. A sub-committee of our technical working group has been formed to provide input into this process. We will also likely hold a workshop on the modelling open to all interested stakeholders.

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
COAG	Council of Australian Governments
Commission	See AEMC
DER	distributed energy resources
ESB	Energy Security Board
ISP	Integrated System Plan
NEM	national electricity market
REZ	Renewable energy zones
TNSP	Transmission network service provider