Submission to COGATI Access and Charging consultation paper

30 April 2019

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About the Public Interest Advocacy Centre

The Public Interest Advocacy Centre (PIAC) is an independent, non-profit legal centre based in Sydney.

Established in 1982, PIAC tackles barriers to justice and fairness experienced by people who are vulnerable or facing disadvantage. We ensure basic rights are enjoyed across the community through legal assistance and strategic litigation, public policy development, communication and training.

Energy and Water Consumers' Advocacy Program

The Energy and Water Consumers' Advocacy Program (EWCAP) represents the interests of low-income and other residential consumers of electricity, gas and water in New South Wales. The program develops policy and advocates in the interests of low-income and other residential consumers in the NSW energy and water markets. PIAC receives input from a community-based reference group whose members include:

- NSW Council of Social Service;
- Combined Pensioners and Superannuants Association of NSW;
- Ethnic Communities Council NSW;
- Salvation Army;
- Physical Disability Council NSW;
- St Vincent de Paul NSW;
- Good Shepherd Microfinance;
- Affiliated Residential Park Residents Association NSW;
- Tenants Union;
- Solar Citizens; and
- The Sydney Alliance.

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1. Overarching objectives for/from the NEM

1.1 Context

The National Energy Market (NEM) is in the middle of a transformation from an energy system relying primarily on centralised, fossil-fuel generation with passive demand, to one with a low- or zero-emission generation fleet interacting with more sophisticated and active demand-side behaviour. The uncertainty in future demand, the cost trajectories of new technologies and the potential for new ‘game-changing’ technologies will place a greater importance on the robustness of modelled outcomes and the optionality offered by certain solutions.

In order to fully unlock the benefits of this transition, some investment will be required in the transmission and distribution networks. At the same time, the NEM is also facing challenges to affordability for many residential, commercial and industrial consumers. This creates tension between new investment to unlock the benefits of the future energy system and avoiding exacerbating the current affordability issues.

It is important to contrast the current regulatory frameworks to that of 40 years ago when many of the existing NEM assets were built. At that time, generation and network assets were owned and operated by state government utilities and there were strong social welfare and state economic drivers underlying the sector’s investment decisions – be it programs of rural electrification or providing stable supply for energy-intensive heavy industry. Further, with governments owning the entire energy value chain, for and on behalf of tax payers, commercial issues such as funding and short-term profits were not primary concerns.

Following multiple rounds of economic reforms and restructuring, socialising the total system cost by governments is no longer possible. For-profit corporations (including, to a certain degree, state-owned corporations) pursue a different set of outcomes. This is not a criticism of restructuring or of privatisation, but a recognition that the current industry structure and market design mean that the opportunities to deliver the optimal system-wide outcome are different to what was possible when much of the backbone of the existing interconnected electricity system was built.

1.2 The need for whole-of-system solutions

Ultimately what is needed is a system-wide solution which minimises the cost and maximises the benefits of delivering essential electricity services to consumers. One where all stages of the supply chain are considered – centralised generation, decentralised generation, demand response, energy efficiency and both transmission and distribution networks.

In other jurisdictions, most notably the US, this is done using an Integrated Resource Plan (IRP) by a central planning authority. An IRP will typically specify the optimal technical characteristics, timing and location of centralised generation, network and demand-side investments as well as the optimal retirement of existing assets. Importantly, the centralised planning authority will generally also have the power to implement all the necessary investment decisions in its IRP.

In the NEM, there is no such centralised authority and this role is instead delegated to market forces through a combination of price signals and regulatory oversight. In response to the need for strategic vision in developing the NEM for the future, the Australian Energy Market Operator (AEMO) has developed its inaugural Integrated System Plan (ISP). As stated by AEMO:

> The primary objective of the ISP is to identify a national, strategic plan to support development of the energy system which will deliver safe, reliable, and secure electricity at lowest cost and in the context of government policies.[1]

This is different from an IRP in a number of important ways. Most notably, the ISP only specifies the transmission investment required. Under the current regulatory framework, it does not and cannot direct investment decisions in other stages of the supply chain. Instead, it requires the rest of the industry to respond to the signals set out in the ISP and other signals already part of the NEM in order to achieve the optimal whole-of-system outcome.[2] If this were not to happen, the expected benefits in other parts of the supply chain which are enabled by the transmission investment may not eventuate.

For example, the modelling underlying the ISP may suggest that the optimal outcome is achieved by a transmission network investment between locations A and B in 2025 and the connection of a number of new generators along this line between 2025 and 2030. However, as noted previously, the current ISP specifies only the transmission investment required. Therefore, the ISP development path would identify and help drive the transmission investment between A and B but it would be up to prospective generators (in response to various market signals) to identify the opportunity and act on it to connect along that route within the modelled time period. For this to happen, these market signals must be sufficiently clear and the prospective generators must be sufficiently comfortable with these signals to make investments in line with the ISP modelling. Without this, generators may not connect to the new line in an effective and efficient manner that makes best use of the transmission investment made or supports the best wholesale market outcomes.

1.3 Problem definition

The current regulatory framework is designed to deliver efficiency of incremental investment to a centralised generation and transmission system which has already been ‘built out’. The transformation the NEM is currently going through is not incremental – it is a step change.

What is needed is a planning and investment framework which delivers efficiency for strategic, whole-of-system investments in order to ensure this transformation is delivered in a timely and cost-effective manner. This is the challenge PIAC sees is central to the work the AEMC and ESB are doing through a number of workstreams including COGATI.

Without such a framework, we expect to see the cumulative impacts of individual generation and transmission investments diverging from the optimal system-wide outcome with:

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1 AEMO, *Integrated System Plan*, 2018, 17.

2 For instance, the Marginal Loss Factor (MLF) calculations for each transmission connection point or reports on binding transmission constraints.

- Inefficient generation investment – in terms of the sizing of new generators; their location and impact on the network; the cost to connect each individual generator including those otherwise efficient investments which do not occur; and the geographic and fuel source diversity of the generation fleet as a whole.

- Inefficient network investment – in terms of the shallow connection assets to connect new generation; the deeper assets required to connect the new generation to major load centers; the interconnection of major load and generation regions to make the most of fuel diversity and maintain reliability of supply; and the ability to maintain system security and stability.

- A lack of coordination between generation and network meaning consumers may have to pay twice for the same problem to be attempted to be solved by both a generation and network investment.

- Missed opportunities to explot economies and scale and scope.

- A longer and more expensive transition to a low- or zero-emissions energy sector.

All of these ultimately lead to increasing pressures on consumers through the wholesale and network components of their electricity bills as well the impacts of climate change.

2. Whole-of-system investment frameworks

2.1 Objectives

The frameworks for centralised supply comprise the policy and regulatory obligations as well as the practices of relevant businesses and market bodies in implementing them to plan, deliver and pay for the large-scale generation[3] and transmission network.

PIAC has identified three objectives that the regulatory framework for delivering centralised generation and transmission must deliver, especially in the current context of the NEM's transformation and affordability challenge. We use this as a framework for assessing the need and priority of any reforms to the current framework and the merit of any solutions proposed. The framework must:

1. **IDENTIFY** the most efficient system-wide solution.

    - A NEM-wide planning framework that is outcome-focused and solution-agnostic.
    - It must deliver the services consumers want, at a price they are willing to pay.
    - It must be technology agnostic: treating supply-, network- and demand-side solutions on an equal footing, with regard to both how options analyses are conducted and the financial incentives faced by the investing parties.
    - It must be geographically agnostic: the process should be indifferent as to which NEM-region the solution is physically located so long as the solution achieves the necessary performance characteristics and the assessment captures all the associated costs and benefits.

3 And, increasingly, the potential role for large-scale storage as well

- It must balance the risks and benefits of investing for the long-term to exploit economies of scale and scope where feasible.
- It must also consider the staged implementation of a solution as well as the combination of multiple individual solutions to address the need. Often a coordinated suite of supply-, network- and demand-side solutions may provide the most efficient option and can help address the risk of overinvestment due to future uncertainty.

2. **DELIVER** the solution in a timely and efficient way.

- The parties best placed to deliver the projects must be properly incentivised to do so in a way that delivers the entirety of the modelled benefits (in both time and cost), ultimately to consumers.
- In order to achieve this, the policy and regulatory framework must allocate responsibility and incentives to those parties that have the capacity to manage the various risks.
- Therefore, the party or parties responsible for delivering the investment(s) must be exposed to the consequences of failing to deliver it.
- And equally, the party or parties responsible must also stand to be rewarded for the benefits of delivering the investment efficiently.
- The risks and rewards parties are exposed to must be symmetric with respect to the magnitude of costs and benefits at stake.
- The financial incentives parties receive must be in relation to efficiently achieving the end result, not dependant on the technology of the solution used to achieve it.

3. **RECOVER COSTS** for the delivered solution in the fairest and most equitable way.

- Those who benefit from a given investment should also pay for that investment.
- Where there are multiple beneficiaries, the costs should be recovered proportionally to their share of the benefits.
- Where it is not practical and transparent to identify the beneficiaries, a causer-pays principle should be used.
- Cost recovery should also include the risk, to the extent it exists, of the underutilisation of assets and hence asset stranding.
- Cross-subsidies should only be permitted where they are accepted by informed consumer feedback (such as retaining postage stamp pricing for distribution network tariffs) or immaterially small.

2.2 Barriers to achieving these objectives

In light of the transformation underway in the NEM, the current planning and investment framework cannot achieve the objectives described above. This is due to a range of barriers, which are described below and mapped in Figure 1 against the objectives they impede.

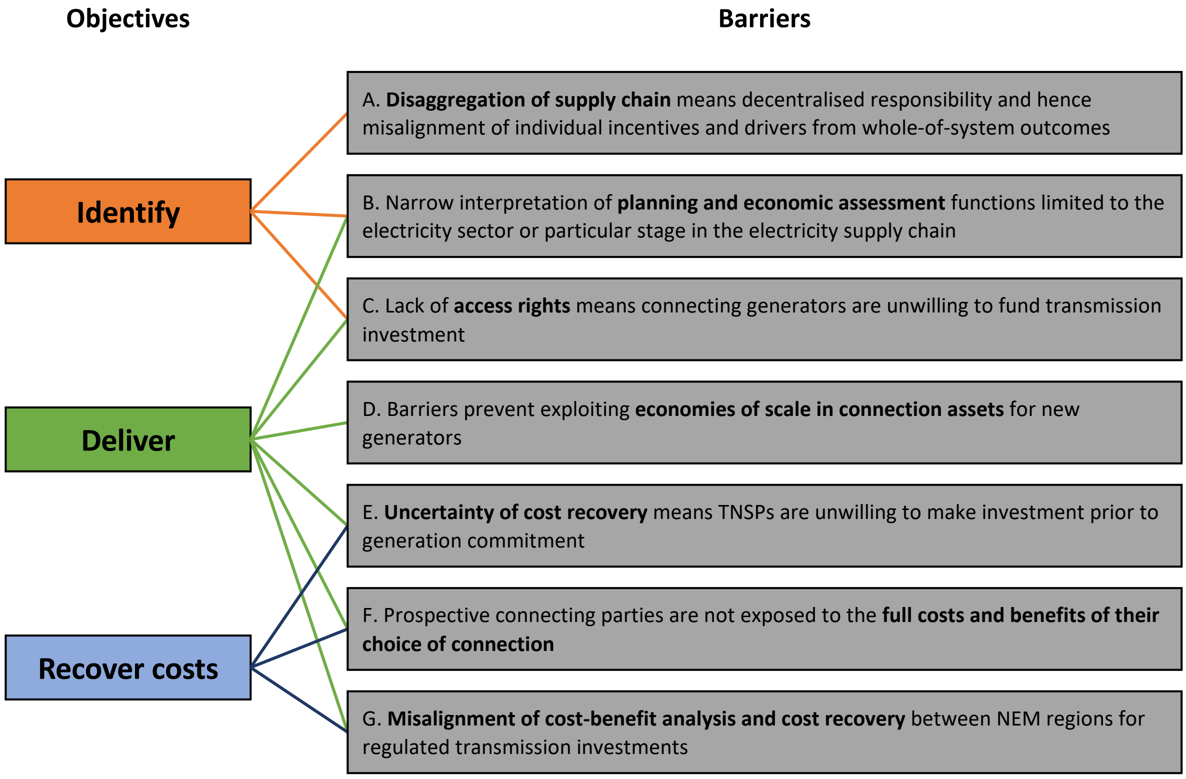

Figure 1 The three objectives which the regulatory framework for centralised generation and transmission must achieve mapped against the barriers which currently impede delivering them for the transforming National Energy Market (NEM).

A. Disaggregation of the supply chain means decentralised responsibility and hence misalignment of individual incentives and drivers from whole-of-system outcomes

In many other jurisdictions the optimal whole-of-system outcome is planned and delivered by a central planning authority. In the NEM, there is no such centralised authority and this role is instead delegated to market forces through a combination of price signals and regulatory oversight. This is especially problematic where a structural change in the transmission and generation system is required rather than incremental expansion and maintenance.

For this to happen, these market signals must be sufficiently clear and the prospective generators must be sufficiently comfortable with these signals to make investments in line with the ISP modelling. Without this, the necessary merchant generator investment may not eventuate in time or at all despite the transmission investment having been made.

B. Narrow interpretation of planning and economic assessment functions limited to electricity sector or particular stage in the electricity supply chain

To date, much of the high-level cost-benefit tests for planning have been based more around incremental investment efficiency rather than whole-of-system optimisation – meaning that each investment is assessed in isolation and not necessarily as an interrelated suite of investments. Continuing to do so risks overlooking the benefits, costs and hence trade-offs which arise from the interrelation of multiple projects. This is especially the case where the projects have substantial impacts across the NEM.

Under the current planning and regulatory frameworks, the use of demand-side options to address both supply and network issues has been limited. There has been considerable commentary and review into multiple potential causes of this including:

- biases created because expenditure on non-network options are treated differently in network regulation than expenditure on network options;
- biases created because the cost-benefit analysis tests only consider impacts (both costs and benefits) within the electricity supply chain; and
- cultural biases against non-network solutions by organisations and decision makers running the tests.

C. Lack of access rights means connecting generators are unwilling to fund transmission investment

Under the current open access regime for generator connection to the transmission network, while they have a right to connect, no generator has any right to access the regional reference node (and hence earn the regional reference price for generation output). Instead, generators may not be dispatched (either only partially dispatched or not dispatched at all) by AEMO due to constraints in the network.

While provisions are in place for generation-funded augmentation to the network to remove these network constraints, the generator which funds them has no assurance that they will benefit from their investment. Instead, the behaviour of existing generators or the entry of a new generator may reinstate the original network constraints.

D. Barriers prevent exploiting economies of scale in connection assets for new generators

The existing regulatory framework was developed when a mature generation fleet and transmission system was already in operation. As such, the regulatory framework is better suited to incremental investment in energy infrastructure rather than delivering more strategic investments such as the coordinated connection of multiple generators in Renewable Energy Zones (REZ).

Being able to exploit economies of scale in connection assets would mean lower connection costs overall (which are ultimately passed on to consumers through lower wholesale prices), potentially more low-cost and low-emissions generators being able to connect (which also lead to lower wholesale prices and faster emissions reductions).

The regulatory framework typically requires new generation to lead network expansion, creating a ‘chicken and egg’ dilemma. New generation projects cannot be committed without transmission access, yet under the current framework it is difficult to justify the necessary transmission investment without committed generation.[4]

[4] The Scale Efficient Network Extensions rule (2011) was meant to capture the benefits of scale economies by building capacity for a cluster of future generation connections. However, it has yet to be used by any party for a number of reasons as outlined by TransGrid in its experience with its Renewable Energy Hub. This is discussed further in TransGrid, *Submission to discussion paper, Coordination of generation and transmission investment*, 18 May 2018, 5.

E. Uncertainty of cost recovery means TNSP unwilling to make investment prior to generation commitment

As noted above, there currently exists a 'chicken and egg' dilemma for transmission investments for multiple expected generator connections. Generation cannot commit without transmission access, yet under the current framework it is difficult to justify the necessary transmission investment without committed generation.

This is especially problematic where a number of new generators are expected to be connected in a single area and the most efficient solution to connect all of these would be to create a single, larger transmission infrastructure to be shared between multiple generators. However, it is unlikely these generators would all connect at the same time or in a coordinated fashion. Therefore, under the current framework, the TNSP would build several smaller connection assets for each generator as they connect, which leads to higher overall costs and (otherwise prudent) generators not connecting at all.

F. Prospective connecting parties not exposed to full costs and benefits of their choice of connection

The connection of a new generator to the transmission system, or the upgrade of an existing one, can impose a number of different costs and benefits on the system as a whole. Currently, generators are only explicitly exposed to some of these, namely: their shallow connection costs and the costs associated with providing any required system strength services as a result of the connection.[5] However, connecting parties are not exposed to other impacts they may have on the broader network such as any deeper network costs they impose on the TNSP.

Further, PIAC and others have noted that the Marginal Loss Factors (MLF) that apply to individual generators have been changing at a faster rate than earlier in the NEM. As the MLF is calculated for each connection point in the transmission network and not apportioned according to a causer-pays principle, there is limited incentive (or signal) for connecting parties to reduce their impact on the MLF of other participants.

G. Misalignment of cost-benefit analysis and cost recovery

The current investment efficiency tests, such as the RIT-T, are designed as a NEM-wide cost-benefit analysis. As a result, the modelling is insensitive to where in the NEM these costs or benefits occur – it only considers the total costs and total expected benefits across all consumers throughout the NEM. This is in contrast to the way these costs are actually recovered through network prices which are primarily based on where the expenditure occurred.[6]

For projects which are incremental expansions or reinforcements of the existing network, this misalignment would not pose a significant issue as the expected benefits from the investment accrue exclusively to consumers within the network's jurisdiction. However, this is not necessarily

5 Exposing the connecting to their impact on local system strength is a new addition to the regulatory framework following the Managing Power System Fault Levels rule change concluded in 2017.

6 There are mechanisms in place to apply network costs across network jurisdictions. However, we consider the effectiveness of these in certain cases to be very limited. For instance, the inter-regional TUOS only applied to the locational component of transmission costs (currently 50%) and does not address the risk of asset underutilisation. This is discussed further in PIAC, *Submission to Coordination of Generation and Transmission Investment options paper*, October 2018, 6-8.

the case for more strategic or nationally significant investments where a significant proportion (even the majority) of benefits may accrue to another jurisdiction.

This misalignment effectively means that one set of consumers may be paying for the benefits received by a different set of consumers and runs counter to one of the fundamental principles of the NEM which is cost-reflectivity. Further, if the misalignment between costs and benefits is large, a particular project may actually have a negative net economic benefit (i.e. an overall detriment) for consumers in one network's jurisdiction despite being positive NEM-wide.

2.3 Proposed solutions

In order to address the barriers discussed above, a range of reforms and solutions are required. Each solution addresses, to a greater or lesser degree, multiple barriers – these relationships are illustrated in Figure 2. Many of these are within scope of the AEMC's COGATI review and the Energy Security Board's (ESB) work in embedding the ISP into the formal regulatory framework.

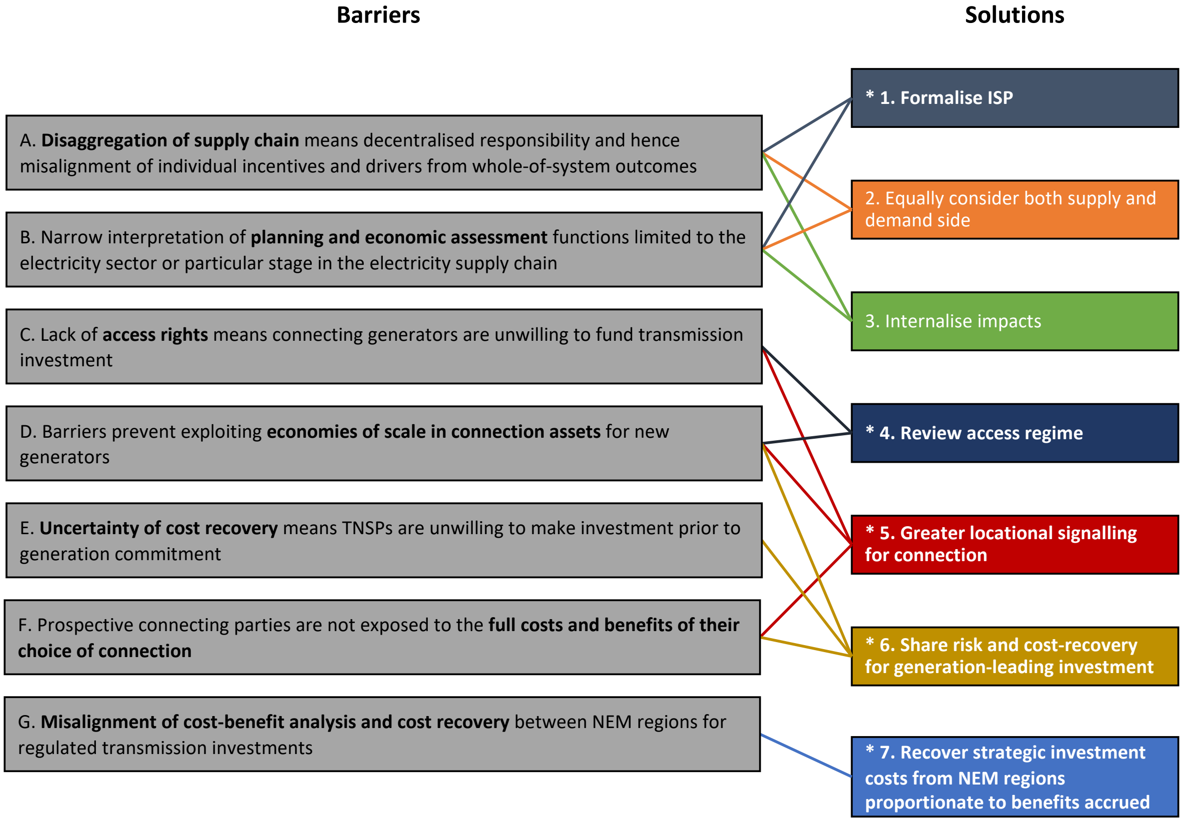

Figure 2 The solutions and reforms proposed mapped against the barriers they address. The solutions and reforms within the scope of the AEMC's COGATI review and the Energy Security Board's work in embedding the ISP into the formal regulatory framework are highlighted.

1. Formalising the ISP within the Rules with thorough public consultation

It is essential that the ISP and RIT-T processes and content are aligned to ensure there is consistency and oversight of the transmission planning and investment decisions, while also ensuring there is no unnecessary duplication of effort which can lead to delays, costs and uncertainty. But at the same time, it is important to note that the ISP and RIT-T perform two similar yet complementary functions to achieve the long-term interests of consumers.

The ISP intends to model the most efficient system for the whole of the NEM based upon the best available information and assumptions at the time. On the other hand, the RIT-T identifies the most cost-efficient solution to a particular identified need.

In addition to formally embedding the ISP into the Rules, it is essential that the information and development path outlined in the ISP is also incorporated into the decision-making processes of generators and other merchant investors. This highlights the importance of a robust, transparent and inclusive engagement process in developing each ISP such that stakeholders and decision-makers are comfortable enough to use the ISP development path in their planning and investing.

2. Equally consider both supply- and demand-side solutions

If the system-wide planning process identifies an opportunity for prudent new investment which benefits consumers, it could theoretically be achieved by:

- A centralised generation or storage project;
- A transmission network upgrade or expansion to unlock existing generation or storage elsewhere in the system;
- A demand response program;
- A program to utilise distributed energy resources; or
- A combination of the above.

In order to identify and deliver the most efficient system-wide solution, it is imperative that the potential solutions (and combination of them) are treated on an equal footing. Therefore, the planning and modelling must fairly consider the different costs, benefits, risks and opportunities offered by solutions in different points in the supply chain.

In addition, the incentives faced by each of the parties that make or influence the decision of which solution to pursue must, wherever possible, align with achieving the most efficient solution overall. For example, regulated network businesses must not have a perverse financial incentive to favour network solutions over non-network solutions.

3. Internalising impacts such as climate change in interpreting the NEO

The electricity sector can play a substantive role in reducing Australia's overall emissions. This is especially true with opportunities to shift the electricity sector to low- or no-emissions options as well as the electrification of energy uses elsewhere in the economy such as heating and transport.

However, the regulatory frameworks as they are currently interpreted may act as a barrier to effectively making use of this opportunity; for instance, the National Electricity Objective (NEO) does not have any explicit reference to any environmental or emissions objectives.

It highlights the need to include the impact on overall emissions achieved by an electricity investment into cost-benefit analyses for investments and, indeed, policy decisions in a robust, transparent and replicable way – i.e.: to internalise the environmental impact of electricity investments. This could be done through a number of different mechanisms such as introducing an explicit price on emissions throughout the economy (such as a carbon tax or emissions trading scheme) or by providing greater clarity and prescription in how to incorporate emissions impacts into interpreting the NEO.

4. Review access regime for generator connections

Providing generators some degree of certainty of being able to access the regional reference price for dispatched energy would strengthen the case for generators funding deeper transmission network upgrades. However, this would not be a simple task and the exact nature of how these rights are accessed and delivered would have significant bearing on the appropriateness of the reform.

Reviewing the open access regime for connections has been suggested on several occasions in the NEM – most recently the substantive work done examining Optional Firm Access.[7] Any changes to the access regime would, most likely, require consequential changes to the transmission charging framework if generators are provided some degree of dispatch rights.

We note that the AEMC's proposal in the COGATI consultation paper for the staged implementation of dynamic regional pricing and generator access rights is an option to be considered and is discussed further in Section 3.

5. Introduce greater locational signalling for connecting generators

As noted earlier, connecting parties are only exposed to some of the impacts (both positive and negative) of connecting to the network. Providing these price signals would better align the optimal solution for them individually to the optimal solution for the system as a whole. There are a number of potential methods to do this.

For example, when a generator connects to the transmission network, there may be upgrades or reinforcement to the deeper network which is required to maintain system security or stability (i.e.: deep connection assets). Under the current arrangements, these costs are socialised and recovered from consumers through the broader TUOS framework. Exposing generators to some or all of such costs would provide a more truly cost-reflective locational signal.

Another example is the use of MLF to provide a stronger, locational signal at the time of investment by reflecting the impact that each individual connecting party has on system-wide loss factors. Connecting parties could have their MLF 'locked in' by AEMO for a standard period of time – allowing the party greater certainty of its future revenue. If a new party were to connect nearby and affect the local MLF, this change would be borne by the second party alone rather than being spread across both parties.[8]

6. Share risk and cost recovery for generation-leading investment

Experience has shown that the current regulatory framework is insufficient to fully realise the benefits of the coordinated connection of new generation.

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7 AEMC, *Optional Firm Access, Design and Testing Final Report*, July 2015.

8 This is described in further detail in PIAC, *Submission to the Coordination of Generation and Transmission Investment discussion paper*, May 2018, 9-10.

In general, PIAC agrees with the AEMC's conclusion that it is inappropriate for consumers to bear the full cost of such generation-leading transmission investment (and hence full risk of underutilisation).[9] However, there is merit in consumers bearing some portion of this risk. Doing so would reduce the risk for merchant investment in the transmission assets and encourage timely generation investment and hence efficient utilisation of the transmission assets which ultimately helps lower the wholesale and network components of consumers' bills. The essential question is, therefore, how to find an appropriate balance between the consumer-funded and generator-funded portions of these investments.

To this end, PIAC has developed a model where consumers bear some costs with the remainder recovered from connecting generators in line with connection utilisation of the REZ which is described in Section 6.

7. Recover strategic investment costs from NEM regions proportionate to the benefits accrued

Strategic projects are those where significant benefits accrue across multiple NEM regions such as those involving major upgrades to interconnectors or national transmission flow paths. As such, the cost recovery for these investments must reflect this in order to be fair and in the long-term interests of consumers.

PIAC considers that, as part of the formal integration of the ISP into the Rules, the assessment framework for strategic projects include an assessment of how the benefits accrue and hence a fair method of cost recovery to reflect this. Such a test could build on the general structure of the existing RIT-T but would need to consider a broader range of issues including, but not limited to:

- The equitable allocation of costs across multiple NEM regions, including whether they are in line with the accrual of benefits as described in Section 5;
- A broader range of benefits and costs which could be considered either directly or qualitatively in the cost-benefit analysis; and
- Determining the need for, and ultimately the structure of, alternative cost-recovery mechanisms if the current regulated cost-recovery methods are unsuitable.

3. Access and dynamic regional pricing

In neither the 2018 final report nor the 2019 consultation papers has the scale of the problem of disorderly bidding been stated. PIAC recommends the AEMC provide data on:

- how often disorderly bidding currently occurs in the NEM;
- the estimated impact on wholesale prices when it does occur;
- the expected prevalence of disorderly bidding in the future with current and predicted changes in the generation fleet, system expansion and other trends; and
- the expected financial impact in the longer-term (in terms of both wholesale market outcomes and investment signals) should nothing new be done to address it.

We note that providing an exact dollar figure of such impacts is complicated as it requires developing a hypothetical outcome based on how multiple parties could have behaved, but a

9 AEMC, *Coordination of generation and transmission investment Discussion Paper*, 2018, p 64.

robust assessment of the financial impact is, nonetheless, important in such policy assessments. It is essential in assessing whether the problem posed by disorderly bidding (both now and in the expected future) is significant enough to warrant addressing and whether the solution proposed is commensurate.

In addition to this fundamental question regarding the proposal of introducing dynamic regional pricing, PIAC has several more specific questions and concerns regarding its working which are outlined below.

The examples outlined in the consultation papers and the webinar necessarily use simplified network configurations. However, any merit in the proposal is inherently tied to being able to implement it in the real world and this requires the model to work in more complicated network and generator configurations. We recommend the AEMC provide more detailed worked examples including how to determine the region to apply the dynamic regional price where there are more transmission lines (including sub-transmission lines).

If a dynamic regional price is applied, in order to ensure the fairness of outcome and preserve appropriate price signals, it is important how the settlement residue is allocated (as a result of the difference between the regional reference price and the dynamic regional price behind the transmission constraint). It is unclear at this stage how this is intended to be allocated; for instance, whether it is to be allocated on the basis of the generators' nameplate capacity or whether it would be linked to the price and quantity they had bid at.

It is also important to understand how any changes to settlement price determinations and access rights interact with other aspects of the regulatory and market frameworks. For instance, the AEMC states that access reform will help address TNSPs' outage selection.[10] However, there already is the Market Impact Component of the Service Target Performance Incentive Scheme (STPIS) which uses financial incentives to encourage TNSPs to minimise the effect of transmission outages on wholesale prices. It is unclear how these two would interact and whether both are, in fact, necessary. For instance, it may be preferable to improve the effectiveness of the STPIS component rather than developing an entirely different mechanism. Further, having two separate mechanisms seeking to drive very similar outcomes risks unintended consequences and at least can lead to unnecessary complexity in their operation and compliance.

PIAC looks forward to discussing these and other issues with the AEMC and other stakeholders.

4. ISP and the delivery of transmission projects

4.1 The need to formalise the ISP in the Rules

The ISP performs a role in the regulatory framework which is, at least nominally, similar to the earlier NTNDP. However, given the transformation currently underway in the NEM, the ISP offers an opportunity to do more than the NTNDP has achieved previously to help ensure the transformation of the NEM occurs in a timely and efficient manner. Therefore, in formalising the ISP in the Rules, there is an opportunity to more fundamentally integrate it into the existing planning and regulatory approval processes for networks.

10 AEMC, *COGATI Implementation – Access and Charging*, April 2019, 9.

The current regulatory and planning processes for network investment, most notably the RIT-T, exist for a very important purpose. Rather than being unnecessary red tape which delays the delivery of essential infrastructure, the RIT-T plays an important role in balancing the competing interests of network investment and affordable electricity supply. The ISP and the RIT-T play related yet different roles and their complementary relationship must be respected and supported.

4.2 Applying the objectives for planning and investment frameworks

Following the overarching principles described in Section **Error! Reference source not found.**, the stages for planning and assessing regulated transmission investments in particular can be considered as:

- Determining an optimal solution for the system as a whole – this would comprise a coordinated portfolio of individual transmission needs or opportunities.
- Determining an optimal solution for each specific transmission project – having considered in greater detail the particular options possible for each project.
- Determining an optimal solution to recover costs for the project identified above.

The first can be conducted by the ISP or a similar planning process. The second can be conducted by the existing RIT-T processes. Given the degree of overlap between these two stages there is merit in clarifying and formalising these processes. For instance, providing greater clarity of how the ISP should be used as an input in the RIT-T for the sake of consistency in modelling and avoiding the unnecessary duplication of effort.

However, the last stage, of determining the optimal solution to recover costs, is not explicitly conducted in the current planning processes. Instead, it is implicit in the Rules for all regulated transmission investments and, therefore, is not of a project-specific basis.

This is insufficient for strategic projects in the current environment as the current regulatory framework was designed to deliver efficiency in incremental investments. As described previously in 2.2, the misalignment of benefit accrual and cost recovery for strategic projects risks exacerbating the current affordability challenges facing many consumers in the NEM.

4.3 Proposed model for incorporating the ISP into existing regulatory framework

PIAC has proposed a model for integrating the ISP into the existing transmission investment framework which is outlined below and in Figure 3. It makes use of the existing RIT-T process as a starting point and augments it to reflect the unique nature of strategic projects where the benefits accrue to multiple NEM regions and not just the one in which the assets are physically located.

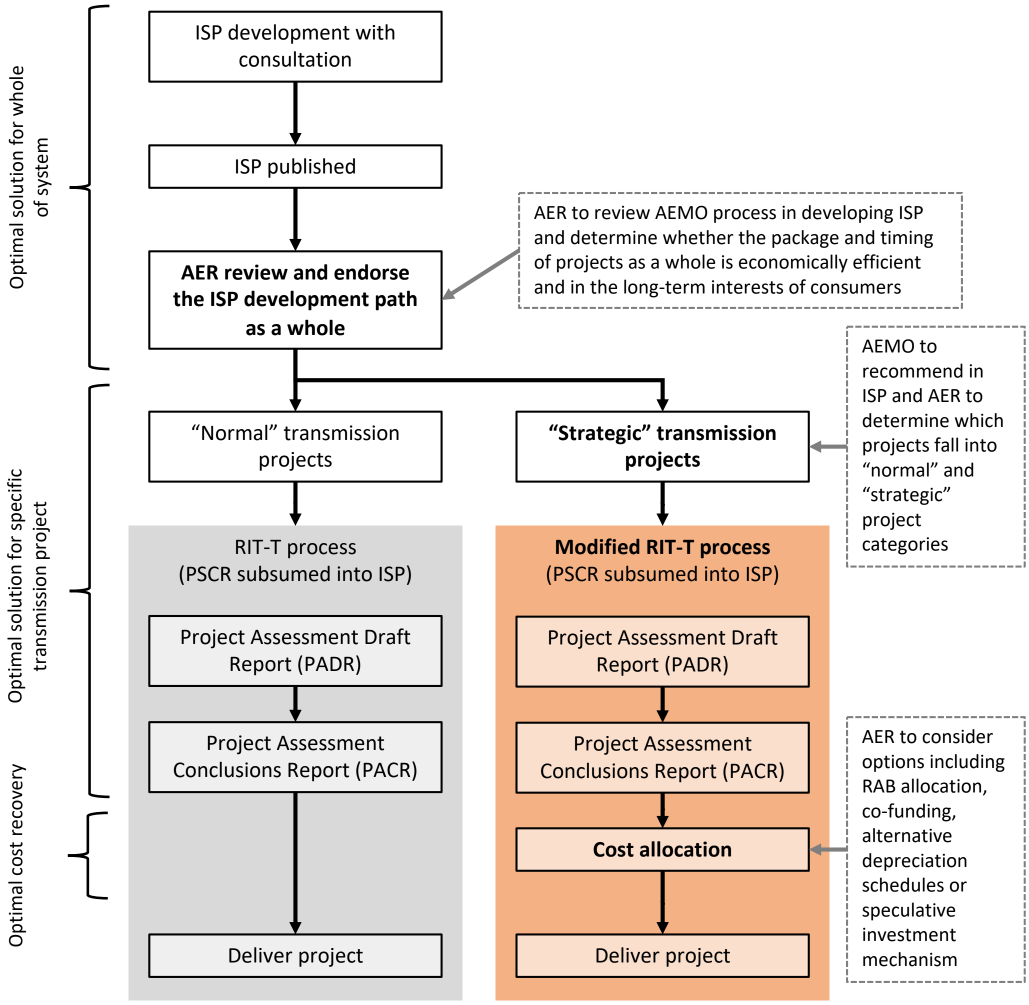

Figure 3 Proposed model for incorporating the ISP into the existing framework for assessing regulated transmission investments. The key changes to the existing framework are bold.

Optimal solution for whole of system

In order to ensure transparency and wide support of the development path, AEMO should consult broadly with all stakeholders in developing the ISP. Further, PIAC considers it essential that the AER also has a formal role in reviewing the final ISP. The complementary roles and skillsets of AEMO as national transmission planner and the AER as the economic regulator and compliance enforcer will help to not only ensure the robustness of the modelling but also help achieve widespread support of the appropriateness of the development path.

Specifically, we consider that the AER should review:

- AEMO's process in consulting on and developing the ISP. This would not only include the appropriateness of the range of scenarios and investment options considered in modelling but also how effectively AEMO had engaged with stakeholders and reflected their feedback in the ISP development process; and

- Determining whether the package and timing of projects as a whole is economically efficient and in the long-term interests of consumers. It is important to note that this assessment by the AER would look at the package of projects as a whole and not individually. Therefore, it would not seek to re-do the cost benefit analyses or other more detailed modelling AEMO has conducted in developing the ISP.

Further, in developing its portfolio of individual transmission projects, AEMO should recommend and the AER determine which of these projects should be considered to be "strategic" transmission projects (i.e.: where significant benefits accrue across multiple NEM regions – such as those involving completely new or major upgrades to existing interconnectors or national transmission flow paths[11]). The market modelling conducted as part of the ISP development should be used as a starting point for the AER's determination.

Optimal solution for specific transmission project

Based on the AER's determination, the individual transmission projects would follow either the regular RIT-T process or a modified version which reflects the unique nature of strategic transmission projects. In either case, the Project Specification Consultation Report (PSCR) would not be required as its function would have been subsumed into the ISP development.

The Project Assessment Draft Report (PADR) and Project Assessment Conclusions Report (PACR), remain but need to consider a broader range of issues through development and consultation including, but not limited to:

- The allocation of costs to multiple NEM regions, including the degree to which they are align with the accrual of benefits (including considering a range of appropriate sensitivities or alternative scenarios);
- A broader range of benefits and costs which could be considered either directly or qualitatively in the cost-benefit analysis; and
- Determining the need for, and potentially the structure of, alternative cost-recovery mechanisms if the current regulated cost-recovery methods are unsuitable.

As a result of this process, the TNSP should identify the optimal size, configuration, use of non-network options and timing of the project to meet the identified need (i.e. the preferred option). In addition, the TNSP may make a recommendation as to whether there is any need for an alternative cost recovery mechanism as described below.

Optimal cost recovery

PIAC considers the AER would be best-placed to make a formal determination as to whether an alternative cost-recovery mechanism is required and what form it should take. It would likely need to be made on a project-by-project basis to allow the AER to appropriately balance the risks and return for businesses and ensure the project is in the long-term interests of consumers.

For the preferred option identified in the PACR, the AER must determine whether the existing cost recovery mechanism for regulated transmission projects is sufficient or whether an

[11] This definition was proposed by PIAC and subsequently adopted by the AEMC in its final COGATI report in December 2018.

alternative mechanism is required. This determination should use the distribution of expected benefits modelled as part of the RIT-T assessment as well as other sources deemed necessary.

The AER should consider a range of factors affecting the equity of risk allocation and cost recovery including but not limited to:

- The alignment of benefit accrual to cost allocation in terms of geography – for instance if the majority of costs would accrue to one NEM region while the majority of expected benefits would accrue to another.
- The alignment of benefit accrual to cost allocation in terms of time – for instance if the expected benefits do not eventuate for many years after the investment must be made.
- The degree to which the benefit accrual is affected by a range of potential alternative scenarios.
- Whether consumers are best placed to bear the utilisation risk of the investment or whether a different party should wear this cost, such as the TNSP as a speculative investment or a generator as part of its connection charges.

If the AER determines that an alternative cost recovery mechanism is required, it should consider options including:

- Revenue or RAB allocation to particular NEM regions according to where the benefits are expected to accrue rather than where the physical assets are located as described in Section 5.
- Alternative depreciation schedules to help address any temporal misalignment of costs recovery and benefit accrual.
- Co-funding of network investment with other parties to recover costs from parties who are better placed to manage the risks or uncertainties.
- Underwriting of network investment to reduce the risks or uncertainties which may otherwise prevent investment proceeding.
- Speculative investment mechanisms such as for generation-leading transmission investment as described in Section 6.

5. Transmission pricing and cost recovery

Transmission pricing and cost recovery is an essential lever to ensuring the three objectives that PIAC identified that the regulatory framework must deliver for centralised generation and transmission planning and investment.

Notwithstanding any necessary changes to transmission pricing (in particular Transmission Use of System or TUOS charging arrangements) as a result of any change to generator access rights, PIAC is particularly concerned with the geographic misalignment between cost-benefit analysis conducted in planning and the way these costs are actually recovered in practice.

As noted previously, the current investment efficiency tests, such as the RIT-T, are designed as a NEM-wide cost-benefit analysis. As a result, the modelling is insensitive to where in the NEM these costs or benefits occur – it only considers the total costs and total expected benefits across all consumers throughout the NEM. This is in contrast to the way these costs are actually recovered through network prices which are primarily based on where the expenditure occurred.

This misalignment effectively means that one set of consumers may be paying for the benefits received by a different set of consumers and runs counter to one of the fundamental principles of the NEM which is cost-reflectivity. And in particular cases, one set of consumers may see a net cost despite the transmission project being a net benefit across the NEM.

Strategic projects, such as those considered in the ISP, are of NEM-wide benefit. The cost recovery for these projects must be similarly NEM-wide.

5.1 Shifting transmission costs across NEM-regions

The current regulatory framework has two primary mechanisms for transferring costs across NEM-regions: inter-regional TUOS (IR-TUOS) and inter-regional settlement residues. While both mechanisms do address the issue of the misalignment of benefit accrual and cost recovery described above, their effectiveness is limited. This is will be exacerbated in the case of strategic projects such as interconnectors and upgrades to national transmission flow paths where a significant portion of the benefits of the investment can accrue across a range of NEM-regions.

Under the current arrangements, TNSPs in each region levy a charge (a modified load export charge) on TNSPs in neighbouring inter-connected regions. Customers pay a share of the costs of transmission used to import electricity into their region from neighbouring regions resulting in a net payment between neighbouring regions.

As the AEMC noted in its Transmission Connection and Planning Arrangements rule change final determination regarding an investment to benefit the “home” region but located in the “other” region:

> There are two key issues which mean that the customers of the "home" TNSP are not bearing the full costs or fully paying for the benefits of the cross-regional investment:
>
> 1. The modified load charge, as calculated under current arrangements, only recovers the locational component of transmission use of system charges. The locational component only covers half of the revenue required to recover the costs of prescribed transmission use of system charges. Thus, approximately half of the costs of cross-regional assets (or at least a significant proportion of them) is borne by the "other" region TNSP's customers. Customers in the "home" region do not bear any of the costs of the non-locational component of the assets built for the cross-regional investment. The operation of the modified load charge is described in more detail in the box below.
>
> 2. The utilisation risk of the cross-regional investment lies with the "other" region TNSP's customers. The application of the modified load export charge changes annually based on the utilisation of the assets. If the "home" TNSP's utilisation of the assets is less-than-expected, the "other" region TNSP's customers may bear a higher proportion of the

locational costs of those assets or potentially all of those costs if the "home" region TNSP's customers do not use these assets at all.[12]

5.2 An alternative mechanism

While the IR-TUOS and settlement residue mechanisms may be unsuitable at addressing significant misalignment of costs and benefits between NEM-regions, they are more suitable for balancing relatively smaller differences across regions. For instance, as they are updated periodically, they are suited to managing seasonal changes in net power flows across regions. Further, given that the IR-TUOS arrangements have only recently been introduced, we question whether there is merit in making significant changes to the methodology so soon.

Instead, we propose to introduce a new mechanism to address the majority of any inter-regional misalignment at the time of investment – essentially at 'year zero.' Any subsequent fluctuations in actual usage, and hence where the benefits accrue to, will be accounted for by the IR-TUOS and settlement residue mechanisms.

Applying the beneficiary pays principle, the allocation of costs to NEM-regions should be in proportion to the expected accrual of benefits to NEM-regions as a result of the investment. We anticipate this should be conducted as part of the investment test for strategic projects as described in Section 4.3. We do not anticipate the calculation of benefits to each NEM-region should be an overly complicated task given the overall complexity of the modelling already being conducted for these projects.

This 'year zero' determination could be made by either proportionately allocating: a) the investment asset values to the RAB of the relevant TNSPs; or b) revenue to be recovered to the relevant NEM-regions; in line with where the benefits are expected to accrue.

Any future investment in the assets (such as repex and augex) would be subject to the same test as the initial investment to determine whether it constitutes a strategic project and, if so, a cost recovery mechanism needs to be developed. There would also need to be provisions to re-open the 'year zero' determination under certain circumstances.

This proposal helps to address both issues with the current IR-TUOS mechanism raised by the AEMC: that the modified load export charge used for IR-TUOS only applies to approximately half of the value of the assets; and that IR-TUOS does not address underutilisation risk. By reducing the misalignment of costs and benefits between NEM-regions from the outset, the fact that only half of the value of the assets can be transferred has a smaller overall impact on the consumer net benefit for consumers. Further, by allocating the RAB value or revenue allocation in line with the modelling (and hence investment driver) it reduces the impact of future changes in actual utilisation levels and the risk of asset stranding.

12 AEMC, *Transmission Connection and Planning Arrangements rule change final determination*, May 2017, p 92.

6. PIAC model for generation-leading transmission investments

New generation projects often face very limited timeframes during which they must meet various requirements to proceed: securing funding, planning approval, lease options, equipment, contractor availability and so on. For successful co-investment, timing for multiple different generation projects would need to align despite these projects being financially independent of each other. Otherwise early connectors will face a 'first-mover' disadvantage, potentially funding a greater share of the investment, being exposed to more timing risk, and effectively cross-subsidising later connections by their competitors.

Furthermore, generators are commercial rivals in the wholesale market as well as in securing project funding. As such they may often be unwilling or unable to share details with respect to financing, forecasting and other commercially sensitive information. They do not and cannot voluntarily co-ordinate to undertake joint investments in transmission capacity.

Consequently, generation projects which would have benefited the NEM – improving wholesale market competition, increasing diversity of supply, and increasing renewable generation – do not get built or are built at a much higher cost than optimal.[13] This results in greater costs to the market and consumers.

PIAC has developed a framework to help address this. It provides a model for how the cost of investment in generation-leading transmission investments (such as a REZ) could be shared between consumers, generators and TNSPs in a way that helps drive efficient system-wide outcomes in a timely, cost-effective and equitable way. It also allows the option for governments to underwrite a portion of the investment cost to help reduce uncertainty.

6.1 Cost-recovery and the 'beneficiary pays / causer pays' framework

The framework seeks to create incentives for efficient behaviour, without imposing unjust distributive consequences:

- In the first instance, the cost of an investment should be paid by those who benefit from that investment, in proportion to their share of the benefits (the 'beneficiary pays' principle).
- If beneficiaries cannot be readily identified, or lack a reasonable capacity to pay, costs should be paid by those who caused them to be incurred.

In the context of a REZ, investment in new transmission assets is 'caused' in an immediate sense by generators seeking to connect to the network. Beneficiaries include generators (who gain the opportunity to access wholesale market revenue), consumers (from lower energy prices due to optimised transmission and generation investment), and TNSPs (who have the opportunity to gain a return on the investment).

13 For further discussion of how current rules have not delivered scale-efficient investment, see TransGrid, *Integrated System Plan Submission*, February 2018, p 13: "SENE [Scale Efficient Network Extension] investments are considerably higher risk and potentially lower reward than investments by a TNSP in its prescribed business… No TNSP has ever successfully established a SENE, and under the current rules, TransGrid considers that this is unlikely to occur in future."

6.2 Defining the REZ

We have defined a REZ as shared transmission assets servicing renewable generation within a geographic area prescribed by a regulatory process. The model would apply to the access, revenue and cost-recovery arrangements for those assets.

The location and total capacity for the REZ would be determined through a planning process such as the ISP. While we are open to exploring options, in line with our forecasting approach, we think it is important for multiple institutions to have input into planning REZs – for example AEMO, the AER and the ESB. This will ensure a variety of sources of expertise (engineering, regulatory, market-based) are considered and different institutional interests represented.

The outcome of the planning process would be geographic zones identified as efficient locations for multiple renewable generation projects. Each zone would have a prescribed 'efficient' capacity level, defined as the capacity to be covered by arrangements for TNSPs to recover costs from generators and consumers set out through a regulatory process. Capacity exceeding that level would be treated as speculative, with cost-recovery arrangements not set out in regulation.

Definitions

- **Renewable Energy Zones (REZ)** – shared transmission assets servicing renewable generation within a geographic area as prescribed by a regulatory process (e.g. the ISP).
- **Prescribed capacity** – transmission capacity within a REZ which falls beneath, or is equal to, the 'efficient' level of capacity as prescribed by a regulatory process
- **Regulated capacity** – transmission capacity within the prescribed capacity range, subject to cost-recovery arrangements set out in regulation
- **Strategic projects** – those whose benefits accrue across multiple NEM regions

6.3 Cost-recovery for generation-leading transmission assets

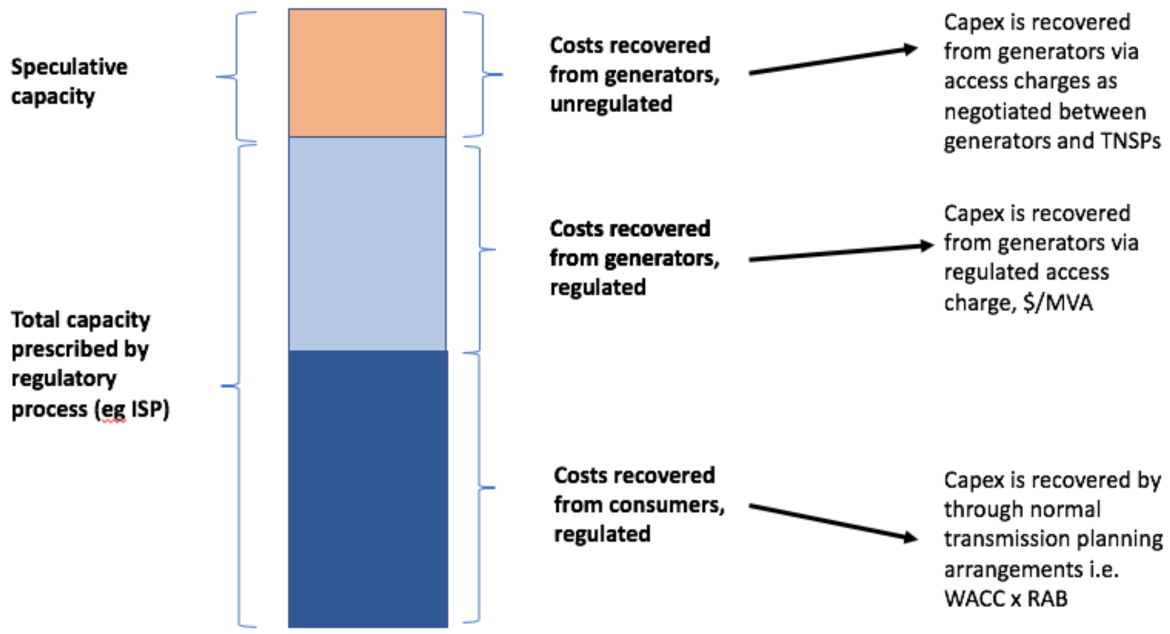

Figure 4 Proposed cost allocation and recovery for REZ assets

Cost recovery for regulated capacity

A fixed portion of the cost of investment would be recovered from consumers in a manner similar to how TNSPs currently recover costs. That is, a fixed portion of the prescribed capacity (say 50 percent) would be subject to regulated cost-recovery arrangements.

The capital cost of regulated capacity would be subject to a fixed, binding rate of return similar to how a weighted average cost of capital (WACC) is currently applied to a TNSP's regulatory asset base (RAB). This rate of return would be guaranteed regardless of the actual utilisation rate. Consumer exposure in the event of underutilisation would be capped at this fixed portion.

A further portion of the cost of prescribed capacity would be recovered from generators, who would pay an access charge to connect to transmission assets covered by the REZ. This charge would be proportional to the generator's nameplate capacity and how early they connected. That is, at any given point in time, the cost for generators to access prescribed capacity would be a fixed rate in terms of $ /MVA. The rate paid by generators would increase with time according to an escalation factor. Generators connecting early would pay lower costs compared to generators connecting later.

The $ /MVA connection charge would be determined by the AER at the time the REZ was planned based on similar principles to the consumer cost-recovery component: allowing the TNSP a reasonable rate of return, given the cost of capital to fund the investment and associated risk. As with the WACC, the AER (and/ or other regulatory bodies) would determine an appropriate rate of return based on the cost of debt and the estimated riskiness of the investment, which would then be 'back-solved' to determine the initial $ /MVA rate for generator connection.

The escalation factor would also be determined by the AER. It represents an uplift in the TNSP's rate of return to reflect the risk that the increase in risk each year that capacity goes unutilised. The earlier the connection, the less risk is borne by the TNSP, and vice-versa.

This schedule of charges makes explicit the sharing of timing risk between generators and TNSPs. Generators could also opt to pay premium free bonds for an option on transmission capacity prior to 'year 0' of the asset life. The lack of a premium would reflect how, under this connection arrangement, no timing risk would be borne by the TNSP.

Cost recovery for speculative capacity

For speculative investments in transmission capacity exceeding the prescribed level for the REZ, TNSPs could set charges and negotiate with generators as they chose. TNSPs could seek high returns via higher generator access charges to compensate for the additional risk of investing in capacity without guaranteed cost-recovery. Alternatively, they could offer capacity cheaply if the marginal cost is low. Generators could choose whether to connect based on the expected value of the investment.

Potential government underwriting of some regulated capacity

Depending on policy goals, it may be appropriate for governments to underwrite some of the investment. This should occur for low levels of utilisation only and should be repaid in the event of higher utilisation. This underwriting/repayment schedule should not apply to speculative capacity the TNSP has built above the prescribed capacity. The TNSP's rate of return applied to the regulated capacity should be adjusted downwards to reflect the lower risk faced by the TNSP.

There are multiple means by which this concept could be implemented. One potential mechanism is as follows: the amount of underwriting could be expressed in terms of the revenue the TNSP would recover at a given utilisation level, smoothed over a fixed period (such as the first five years of the investment). Whatever part of this revenue was not recovered by the TNSP via consumer cost-recovery and generator access charges, would be paid to TNSPs by government during that period. Conversely if the TNSP recovered costs in excess of this level, the additional revenue would flow to government.

6.4 Risk allocation and value proposition for stakeholders

Generators

Under the model generators are protected from the risk of REZ underutilisation. Their access charges depend only on their own investment choices, not on overall utilisation of the transmission asset. This is appropriate as individual generators have little or no ability to optimise the overall use of transmission capacity or to engage in transmission planning for the zone as a whole.

Generators are also protected from the risk of timing misalignment between different generation projects, as the transmission asset is partially underwritten by consumers and/or government based on a plan developed through a regulatory process. Again, this is appropriate as generators have little or no ability to coordinate financing or other approvals for projects other than their own.

In lieu of bearing these risks generators pay a rate of return premium to TNSPs, who bear some of the timing risk. Generators can choose to take on some of this risk by connecting early and are incentivised to do so through lower access charges.

TNSPs

TNSPs take on some underutilisation risk via the portion of investment costs that is not underwritten by either government or consumers. This is appropriate since TNSPs have some ability to plan and forecast utilisation rates for transmission assets.

Revenue from generator access charges is proportional to the rate of utilisation. This gives TNSPs an incentive to develop accurate forecasting methodology, and to provide good information to regulators, in the process of determining the ‘efficient’ prescribed capacity level.

The model represents a value proposition for TNSPs in that they receive an uplift in their rate of return from generator access charges on regulated capacity, in return for taking on some underutilisation risk. They are also protected from some, but not all, of the risk of asset stranding through the guaranteed cost-recovery floor. This protection should be accounted for in the rate of return as determined through the regulatory process. The higher the proportion of guaranteed cost-recovery, the lower the risk premium incorporated into the WACC.

Consumers

Minimising costs and risk exposure for consumers is a priority. Consumer interests are at the heart of the NEM, and consumers have little or no ability to manage the risk of underutilisation or asset stranding.

Under the model consumer exposure to the risk of underutilisation is capped at a fixed, limited portion of the investment value. This limits their liability under all scenarios, including the ‘worst case’ where utilisation is low.

At the same time, consumers share some risk with TNSPs by underwriting a portion of the transmission investment, calculated by applying a standard, binding rate of return to a portion of the prescribed capacity. This represents a value proposition for consumers because it prevents uncertainty arising from being socialised to consumers, in the form of inefficient transmission investment and a less competitive wholesale market.

Government

Government has the option of taking on some underutilisation risk by underwriting some portion of the capex for prescribed capacity. This may be appropriate given policy priorities including supporting infrastructure investments for broader social, economic and planning purposes, and reducing risk exposure for consumers. It represents a value proposition as there is also the potential to earn a return if utilisation exceeds the underwritten level.