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Regulatory treatment of large, discrete electricity transmission investments

A report for the Australian Energy Regulator

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Executive Summary

The National Electricity Market (NEM) is undergoing a significant transition away from its previous heavy reliance on fossil fuel generation to one in which demand is predominantly met by decentralised sources of renewable energy, including both large scale plants, distributed energy resources and storage. The continued incorporation of new sources of renewable energy into the NEM requires the development of substantial additional transmission capacity to accommodate this transformation.

Over the last few years there have been extensive changes made to regulatory processes to better coordinate and facilitate investments in electricity transmission networks. In particular, there has been a move towards greater centralisation of planning through the Australian Energy Market Operator's (AEMO) development of the Integrated System Plan (ISP).

The combination of the scale of the investments foreshadowed in the ISP (unprecedented in recent times) and uncertainty as to the benefits and costs of these investments poses a new and unique challenge for the existing regulatory processes that assess proposed transmission investments.

This report focuses on how the large, discrete transmission investments contemplated by the ISP can be delivered so as to best contribute to the long term interests of consumers, consistent with the National Electricity Objective (NEO). It is structured around two principal themes, ie:

- the means by which the incentives for service providers can be refined to optimise the delivery of large, discrete transmission projects, in circumstances in which competition is not sufficiently strong to provide this assurance; and
- the circumstances under which it may be beneficial to introduce competition to the provision of large, discrete transmission investments.

Challenges in delivering large transmission projects

The magnitude of the investment projects foreshadowed in the ISP, both individually and as a collective, brings into focus the regulatory processes that will be engaged to assess and approve them. Once approved and built, consumers will be paying for these projects for decades into the future, and so it is critical to the long term interests of consumers that they:

- are procured at least cost to consumers; and
- proceed only where they provide benefits to consumers.

The size of these projects also gives rise to significant additional risks to transmission network service providers (TNSPs). The Australian Energy Regulator (AER) operates a regulatory framework that provides TNSPs with incentives to outperform the forecast costs of undertaking investments. Although TNSPs have always faced the risk that they will under-perform against the cost of forecast capital expenditure, these risks have typically been mitigated since under-performance on any one project:

- is generally diluted within a portfolio of projects in which there might also be over-performance on other projects; and
- can be managed in the context of the five-yearly determination process since TNSPs' performance is assessed in aggregate against a 'bucket' of approved capital expenditure.

However, such forms of risk mitigation are either unavailable or ineffective for large, discrete transmission projects.

There is also significant uncertainty associated with both the benefits and costs of large, discrete projects. This gives rise to additional challenges because:

- much of this uncertainty appears to be intrinsic to individual projects and their interactions with existing regulatory processes; and
- the regulatory process pre-supposes that these uncertainties will narrow as a project proceeds towards approval and construction, whereas there is evidence that this is not occurring for large, discrete projects.

Options assessment framework

We examine the existing approach in the NEM and potential alternatives by reference to an analytical framework that assesses:

- the balance that each strikes in the spectrum between, on the one hand, 'high-powered' policies that incentivise service providers to achieve productive efficiencies through offering the prospect of economic rent, as against 'low-powered' policies that offer less incentive for productive efficiencies;
- the sharing of risks that each achieves as between consumers and the TNSP, and potentially other parties such as generators, DNSPs or governments;
- the trade-offs inherent in the time and complexity associated with implementing each potential option as against the proportion of ISP expenditure to which it could be applied;
- the costs of implementing and administering each option, which includes not just the direct costs of regulation but also the additional costs incurred by participants in their interactions with regulatory arrangements; and
- the potential for dynamic efficiency gains to be realised, where such gains arise by facilitating non-standard solutions to a recognised need – with this being achieved by facilitating the widest potential scope for the forces of competition, where that can be effective.

Optimising project delivery by administrative means

Regulators often introduce administrative means to provide (or increase) incentives for service providers to strive for efficiency in the level of investment and the practical delivery of those investments in the long term interests of consumers. The nature of the incentives required in the context of large transmission investments are inherently linked to the intrinsically higher degree of uncertainty as to the expected benefits and costs of these projects.

Uncertainty around the benefits and costs of these investments necessarily extends to uncertainty regarding cost recovery for TNSPs. TNSPs are likely to be risk averse – reflecting the investors that their low risk and stable cash flows attract, and commensurate with assumptions that underpin the allowed rate of return.

The existing regulatory mechanisms in the NEM encourage TNSPs to over-forecast large project costs. However, the intrinsic uncertainty associated with large, discrete projects, combined with the prospect of penalties under the regulatory regime, also means that TNSPs are likely to face a degree of risk in relation to these projects that is greater than that for 'business as usual' investments. The combination of these effects can be expected to give rise to demands for a 'buffer' between a TNSP's forecast costs and a best estimate of project costs. The existence of this buffer is likely to result in consumers paying more than is necessary for large, discrete projects, or even in these projects not proceeding.

In this report we identify five complementary administrative means by which the AER may be able to promote the long term interests of consumers by encouraging risk averse TNSPs to undertake large transmission investments with a reduced risk buffer, despite their intrinsic uncertainty – which we summarise in the figure below.

Figure E1: Regulatory reform options to optimise delivery of large projects

Underpinning each of these administrative means is the need to promote the long term interests of consumers by encouraging TNSPs to make efficient investment decisions in relation to large, discrete transmission projects. These administrative means increase the predictability of the regulatory framework – a process that offers increased confidence:

- for consumers that large discrete transmission projects are being delivered efficiently and without excessive levels of cost buffering; and
- for TNSPs, so they have less incentive and ability to inflate cost forecasts in their contingent project application.

We note that a consequence of increasing the predictability of the regulatory framework, particularly as it relates to the assessment of expenditure once made, is that the risk of cost overruns is shifted onto consumers (and potentially other parties such as government). This risk transfer can be regarded as a desirable trade-off to induce risk averse investors to take on uncertain projects at a lower expected cost. Further, the nature of the proposed administrative means is such that they should provide the AER and consumers with greater confidence that the expenditure incurred by TNSPs is prudent and efficient.

Addressing the issues raised by large, discrete transmission projects without shifting some risks towards consumers is likely to require the entry of TNSPs that are willing to accept a greater degree of risk. The remainder of this report introduces potential means by which the procurement of transmission projects could be opened to new entrants through competitive tendering.

Introducing competition to deliver large projects

We understand that construction of transmission projects is typically already tendered, since:

- incumbent TNSPs generally do not have in-house construction capabilities; and
- tendering may assist a TNSP in demonstrating that it has been prudent and efficient in undertaking its capital expenditure.

One of the key benefits to the introduction of competition is the additional rigour that this provides in seeking innovative solutions, a process that is difficult to incentivise by administrative means. The potential scope for efficiency gains from additional innovation, and the presumptive risk aversion of existing actors within the planning and regulatory framework, is therefore an important factor when considering the merits of introducing competition.

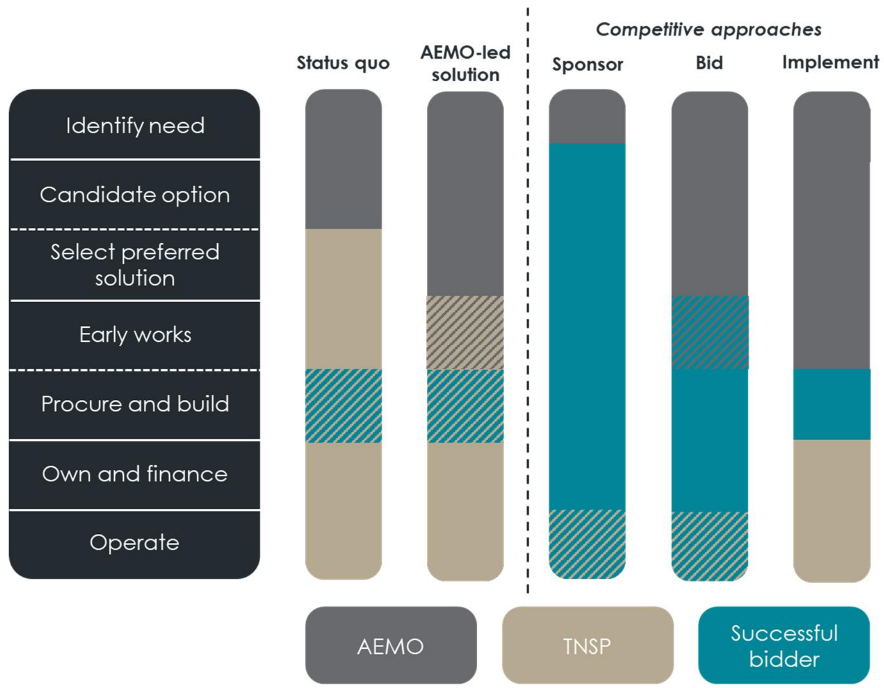
Each of the options for introducing competitive tension to the procurement of large, discrete transmission projects that we assess in this report would involve significant and potentially complex changes to the existing processes in the NEM. For instance, some options may require changes to the scope of AEMO's planning role, either to extend this to specifying the solution by applying the RIT-T, or by reducing the scope of the planning role through the use of a competitive process to identify the best solutions to a system need.

These options are:

- sponsor-based competitive processes, where AEMO would select the best and most cost-effective solution to an identified need from competing tenders;
- bid-based competitive processes, where AEMO would select the best and most cost-effective means of implementing, owning and operating the solution that it itself has selected; and
- implementation-based competitive processes, where the AER would select the best and most cost-effective means of managing the implementation of the solution that AEMO has selected.

The figure below depicts the varying scope of the roles and responsibilities under each of these options.

Figure E2: Models for introducing competition to transmission delivery



The appropriate arrangements by which large, discrete transmission investments are planned, selected, delivered and remunerated are inherently linked to the prevailing circumstances. It follows that any assessment of the different models of competition and regulation requires a considered examination of the circumstances in which they may operate effectively and whether these circumstances arise in the NEM context.

At a very high level, there are three factors related to cost and competition that determine the extent to which competitive procurement can be used as a means to assist in the delivery of large, discrete transmission investments. These are:

- the extent to which potential gains from innovation are available, which is also linked to the degree of information asymmetry between the TNSP and the service provider;
- the extent to which existing decision-makers (such as the TNSP and AEMO) are capable of innovation that would achieve efficient outcomes over the long run, or whether these bodies can be presumed to be risk averse and so prefer more conventional means of meeting power system needs; and
- the extent to which there is the prospect of a workable degree of competition that would allow functions requiring innovation to be sourced externally, which turns on:
  - the economies of scale and scope available to the incumbent;
  - the degree of investment separability from the incumbent's network;
  - the extent of cooperation required from the incumbent; and
  - whether there is a sufficient scale of investment to encourage wide participation.

1. Introduction

The National Electricity Market (NEM) is undergoing a significant transition away from its previous heavy reliance on fossil fuel generation to one in which demand is predominantly met by decentralised sources of renewable energy, including both large scale plants, distributed energy resources and storage.

Existing electricity transmission networks have been developed with the purpose of transporting electricity from large thermal generators to demand centres. The continued incorporation of new sources of renewable energy into the NEM requires the development of additional transmission capacity to accommodate this transformation.

Over the last few years there have been extensive changes made to regulatory processes to better coordinate and facilitate these investments. In particular, there has been a move towards greater centralisation of planning through the Australian Energy Market Operator's (AEMO) development of the Integrated System Plan (ISP).

The combination of the scale of the investments foreshadowed in the ISP (unprecedented in recent times) and the uncertainty as to the benefits and costs of these investments poses a new and unique challenge for the existing regulatory processes that assess proposed transmission investments.

1.1 Scale of new investments

The large, discrete transmission projects that have been advanced in the ISP also represent a transformational change for many transmission network service providers (TNSPs) in the NEM. Over the last decade, the regulated asset bases (RABs) for TNSPs have remained relatively stable, with estimated total RAB for NEM TNSPs as at 30 June 2020 being $20,761.6 million.[1] By comparison, projects advanced through the ISP are expected to contribute a further $10 billion to $19 billion of capital expenditure on new transmission assets. The scale of the potential investments can also be gauged by ISP's contemplation that TransGrid, the NEM's largest TNSP with a RAB of $6,652.7 million,[2] could double that RAB by undertaking projects of which the six largest are likely to be:[3]

- Project EnergyConnect, establishing interconnection between New South Wales and South Australia and connecting renewable generation along its route, at an estimated cost of $1.53 billion;
- QNI Medium, establishing greater interconnection between New South Wales and Queensland and connecting renewable generation along its route, at an estimated cost of between $1.04 billion and $1.93 billion;
- QNI Large, establishing further interconnection between New South Wales and Queensland and connecting renewable generation along its route, at an estimated cost of between $0.68 billion and $1.25 billion;
- Project VNI West, establishing greater interconnection between New South Wales and Victoria and connecting renewable generation along its route, at an estimated cost of between $0.94 billion and $2.41 billion depending on the option selected;
- Humelink, establishing greater connection between demand in Sydney and renewable generation being constructed as part of Snowy 2.0, at a cost of between $0.95 billion and $1.76 billion; and

[1] AER, *State of the energy market*, Data update November 2019, 27 November 2019.

[2] Nominal, 2019-20. AER, *TransGrid transmission determination 2018 to 2023: Attachment 2 – Regulatory asset base*, Final decision, May 2018, p 2-9.

[3] AEMO, *Draft 2020 ISP transmission outlook summary*, 12 December 2019.

- Northern NSW, allowing for the connection of new generation in Northern New South Wales at a total cost of between $1.11 billion and $2.06 billion;

The magnitude of these projects, both individually and as a collective, brings into focus the regulatory processes that will be engaged to assess and approve them. Once approved and built, consumers will be paying for these projects for decades into the future, and so it is critical to the long term interests of consumers that such projects:

- are procured at least cost to consumers; and
- proceed only where they provide benefits to consumers.

However, the size of these projects also gives rise to significant additional risks to TNSPs. The AER operates a regulatory framework that provides TNSPs' incentives to outperform the forecast costs of undertaking investments. Although TNSPs have always faced the risk that they will under-perform against the cost of forecast capital expenditure, these risks have typically been mitigated since under-performance on any one project:

- is diluted since it manifests within a portfolio of projects in which there might also be over-performance on other projects; and
- can be managed in the context of the five-yearly determination process since TNSPs' performance is assessed in aggregate against a 'bucket' of approved capital expenditure.

Such forms of risk mitigation are either unavailable or ineffective for large, discrete transmission projects that are approved through the contingent project process.

1.2 Intrinsic uncertainty of new investments

There is also significant uncertainty associated with both the benefits and costs of many ISP projects. This can give rise to challenges because:

- much of this uncertainty appears to be intrinsic to individual projects and their interactions with existing regulatory processes, a phenomenon that may not be within the ability of TNSPs to manage; and
- the regulatory process pre-supposes that these uncertainties will narrow as a project proceeds towards approval and construction, whereas there is evidence that this is not occurring.

We describe further below the source of these intrinsic uncertainties.

1.2.1 Uncertainty of project benefits

The benefits of these large, discrete transmission projects are often uncertain, depending upon assumptions as to:

- the evolution of demand for electricity, taking into account macroeconomic conditions and developments in the potential for increased demand response;
- the future costs of generation technologies in the face of continued rapid change;
- the operation and retirement of the existing fleet of generation plant; and
- the policy direction of Australian governments, which is increasingly 'baked in' to the planning process through the ISP.

These assumptions are often subject to significant uncertainty and best estimates can change quickly. Recent evidence serves to demonstrate this. For example:

- it appears reasonable to expect that the Covid-19 pandemic will have a material short-term impact on the demand for electricity and potentially a long-term impact on the consumption patterns of consumers; and

- Tasmania has recently proposed a renewable energy target that would result in 200 per cent of its electricity needs being met by renewable energy by 2040.[4]

1.2.2 Uncertainty of project costs

The costs of these large, discrete projects are similarly uncertain. Most of the ISP transmission projects serve to increase interconnection capacity between NEM regions, increase connection with renewable energy zones (REZs) or both. These projects represent new challenges for TNSPs since they generally require them to extend the physical reach of their networks through the construction of entirely new transmission lines, rather than augmenting existing capacity.

This means that the estimated costs of these projects are subject to considerable uncertainty, because:

- TNSPs do not have recent experience of projects of this type and scale, with few best practice examples against which to benchmark; and
- route design for new transmission lines can affect costs substantially but TNSPs' ability to select routes may often be affected by environmental approvals processes, the cost and timing of which may not be in their close control.

Illustrating this uncertainty, the AER's RIT-T decision for Project EnergyConnect notes that the best estimate of the total capital expenditure on the project is $1.53 billion. However, the AER also cites ElectraNet as stating that costs of the preferred option are estimated on the basis that only 1 to 15 per cent of the project had been defined, such that the accuracy for this estimate is:[5]

- -15 to -30 per cent on the low side; and
- +20 to +50 per cent on the high side.

These parameters imply that the cost of the preferred option may reasonably fall between $1.07 billion and $2.23 billion.

The uncertainty of project costs is exacerbated by the existence of a skills shortage for professional project managers, bid teams and skilled labour.[6] The number of large transmission projects may contribute to these shortages, potentially giving rise to:

- higher costs to deliver new transmission investments;
- longer lead times and project timeframes to procure the necessary equipment and services to deliver transmission investments; and
- requirements for more early planning of transmission investments without regulatory certainty.

1.2.3 Interaction with regulatory process

The regulatory process for approving transmission investments operates under the presumption that the ranges of uncertainty surrounding benefits and costs will narrow as consideration of a project proceeds. However, there is evidence that the narrowing of such uncertainties is not occurring in relation to some of the large, discrete projects that are currently (or have recently) undergone regulatory scrutiny.

This means that the AER is being asked to consider approval of projects in circumstances in which a great deal of uncertainty continues to exist about both:

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[4] Tasmanian government, *The draft Tasmanian renewable energy action plan 2020*, May 2020, p 4.

[5] AER, *Determination that the preferred option satisfies the regulatory test for transmission: Decision – South Australian energy transformation*, January 2020, pp 79-80.

[6] Infrastructure Australia, *An assessment of Australia's future infrastructure needs | The Australian infrastructure audit 2019,* June 2019, p 237.

- the extent to which the project presents net market benefits; and
- the extent to which the forecast project costs represent the best estimate of efficient costs.

For example, in the Project EnergyConnect RIT-T cited above, the AER was presented with an estimate of net market benefits for the project of $924.3 million. However, the AER took the view that ElectraNet had made a number of unreasonable assumptions and estimated a range for benefits of between $234.0 million and $315.2 million.[7]

These net market benefits are calculated against the central estimate for capital expenditure of $1,530 million. However, we describe above that the cost of Project EnergyConnect is uncertain and may reasonably be as high as $2,230 million – a level at which the project would not give rise to net market benefits on the AER's assessment of benefits.

This presents the prospect that:

- the AER may approve projects for which the underlying net market benefit is not positive or may become so after approval; or
- the AER may approve projects for which outturn capital expenditure will be very different to the forecast capital expenditure.

We note that there is still scope with the regulatory framework for projects to be delayed in circumstances in which the existence of net benefits is not certain. For example, the AER specifically noted in its RIT-T for Project EnergyConnect that if there were to be an updated assessment of costs, or any updated assessment of parameters that affect market benefits, then ElectraNet should consider whether a reapplication of the RIT-T is required and provide evidence of that consideration to the AER.[8]

1.3 Scope of this report

This report focuses on how the large, discrete transmission investments contemplated by the ISP can be delivered so as to best contribute to the long term interests of consumers, consistent with the National Electricity Objective (NEO).

We review whether the existing economic regulatory framework for determining the maximum allowed revenue a TNSP can earn for the provision of services enabled by that investment remains appropriate for the delivery of these projects. Our focus includes the contingent project and associated regulatory arrangements that govern the process for determining the remuneration of transmission investments.

These features of the regulatory framework adopt an approach often described as 'incentive regulation', in which TNSPs nominate a forecast level of expenditure and are permitted to retain a part of any over- or under-performance relative to this benchmark. Our report seeks to assess whether changes to these arrangements, when applied to large, discrete transmission projects, could give rise to the potential for improved long term outcomes for consumers.

A strong feature of the present regulatory arrangements for remunerating transmission investment, however, is the de facto (ie, not legislated) geographic monopoly held by non-Victorian TNSPs in relation to the procurement or building, ownership and operation functions for new

[7] The key factor driving these differences was that ElectraNet had assumed that gas generators in South Australia must produce at a minimum load factor based on historical operation. This had the effect of increasing materially the amount of electricity produced by gas fired generation without the interconnector, with the result that the construction of the interconnector was modelled as giving rise to significant fuel cost savings.

[8] AER, *Determination that the preferred option satisfies the regulatory test for transmission: Decision – South Australian energy transformation*, January 2020, p 45.

transmission infrastructure. The existence of this de facto monopoly has two important consequences, ie:

- it circumscribes the range of options for potential reform of the regulatory arrangements applying to the remuneration or large transmission investments; and
- through providing TNSPs with a strong ability to influence the selection of the preferred solution to any transmission-related need, it also circumscribes the potential for more innovative, non-network solutions to any given transmission need.

Accordingly, our report also seeks to identify and evaluate alternative approaches to procuring transmission investments, beyond the limitations implied by the existing de facto geographic monopoly framework. The potential for alternative arrangements that fall outside the existing constraints arises in relation to:

- the more ready enablement of innovative solutions to any given ‘transmission’ need as against the innate preference for TNSPs to pursue network-focused solutions;
- the potential for competitive tension to minimise the estimated and actual costs of a transmission investment; and
- the potential for TNSPs or other parties to take on project risks, including the risks associated with early works, prior to costs being approved by the AER.

Despite the recent changes made to bring a more centralised approach to transmission planning, the regulatory framework within which solutions to system needs are procured has not altered to address the challenges we describe above. Consistent with this evolution, our report does not seek to revisit the approach to the planning of transmission investments, but rather focuses instead on alternative approaches to each of the subsequent stages of the regulatory process.

1.4 AER’s objectives

In its guidance as to priorities for our review, the AER has stated that it seeks a revenue determination framework that, to the greatest extent possible, achieves outcomes in which:

- expenditure on large transmission projects is efficient and allowed revenues set by the AER reflect this – for these purposes, ‘efficient expenditure’ is that which results in the lowest cost to consumers over the long term.
- any perverse incentives associated with proposing and assessing expenditure for large transmission projects under the current framework are corrected/minimised to the greatest extent possible.
- risks are allocated to the party best placed to manage them, ie:
- consumers pay only for a reasonable level of project risk; and
- TNSPs are willing to bear a reasonable level of project risk (and, or including, to undertake early works);
- competition is relied upon where possible and beneficial to do so, and regulation is deployed where this is not possible/beneficial;
- rigorous assessment of ISP projects is balanced with a robust and efficient process so these projects can be built by the time they are needed;
- stakeholder input and confidence is promoted;
- any changes are compatible and work with the rest of the economic regulatory framework that will remain in place;
- potential changes to the timing (eg, acceleration or deferral) or the need for a project (eg, halting) in a development path in the ISP are accommodated, even after a project has passed the revenue determination process (recognising that such eventualities may be unlikely, but are possible); and

- that there is no intrinsic need or incentive for additional government intervention or underwriting.

1.5 Structure of this report

The remainder of our report is structured as follows:

- section two introduces the analytical framework that we apply to assess the existing arrangements in the NEM and potential changes to those arrangements;
- section three summarises the regulatory framework currently applied in the NEM to incentivise, procure and remunerate transmission investments;
- section four introduces a spectrum of administrative options for providing incentives to optimise delivery of large, discrete transmission projects and assesses the trade-offs involved in implementing these investments; and
- section five reviews means by which competitive tension could be brought to bear in relation to selecting, owning, financing and managing the building of large, discrete transmission projects, drawing on experience in the NEM and other jurisdictions to assess the potential effect of change.

2. Framework for analysis

Our report is structured around two principal themes, ie:

- the means by which the incentives for service providers can be refined to optimise the delivery of large, discrete transmission projects, in circumstances in which competition is not sufficiently strong to provide this assurance; and
- the circumstances under which it may be beneficial to introduce competition to the provision of large, discrete transmission investments.

We examine the existing approach in the NEM and potential alternatives by reference to an analytical framework that assesses:

- the balance to be struck in the spectrum between, on the one hand, 'high-powered' policies that incentivise service providers to achieve productive efficiencies through offering the prospect of economic rent, as against 'low-powered' policies that offer less incentive for productive efficiencies;
- the potential for dynamic efficiency gains to be realised, where such gains arise by facilitating non-standard solutions to a recognised need – with this being achieved by facilitating the widest potential scope for the forces of competition, where that can be effective;
- the sharing of risks that each of these options achieves as between consumers and the TNSP, and potentially other parties such as generators, distribution network service providers (DNSPs) or governments;
- the trade-offs inherent in the time and complexity associated with each potential option as against the proportion of contemplated ISP expenditure to which it could be applied; and
- the costs of implementing and administering each option, which includes not just the direct costs of regulation but also the additional costs incurred by participants in their interactions with the regulatory regime.

2.1 Potential for dynamic efficiency

The genesis for the AER's review of the arrangements by which large, discrete transmission investments are planned, selected, delivered and remunerated is the presence of a substantial and imminent pipeline of such projects, as identified by the ISP and related processes.

In that context, it is tempting to confine the scope of the challenge to a review of the arrangements by which the relevant investment projects are firmed-up as to their size, scope and timing, and then delivered. However, an important lesson from economic history – including the evolution of arrangements for the regulation of monopoly infrastructure – is that the greatest potential for efficiency gains often lies in facilitating innovative solutions to identified needs.

Electricity transmission infrastructure has for many decades been regarded as performing a relatively clear function, for which there is a stable and enduring requirement. On its face, however, the depth and speed of the transition that is taking place in relation to the generation and storage of electricity has the potential also to induce significant change to the transmission function.

Expressed most simply, the trend towards much smaller scale and decentralised generation and storage technologies raises deep questions as to the long-term centrality of large scale transmission infrastructure in an efficiently-organised electricity system. At a minimum, these trends have the potential to expand the envelope of close substitutes for large scale transmission investment.

In our view there is a strong, in principle case for being wary of the traditional perspective as to the stability and enduring nature of the transmission function. Accordingly, the task of reviewing the arrangements by which ‘transmission’ solutions to identified needs are selected and delivered should give significant emphasis to the potential for dynamic efficiency gains in the form of facilitating alternative, close substitutes for either:

- transmission infrastructure itself, ie, solutions that may not involve such large scale, discrete investment projects; and/or
- existing, generally accepted means by which transmission is designed and built.

For these reasons, an important element of our evaluation framework is the potential for various options to facilitate non-traditional solutions of the form noted above.

In addition to the practical considerations of the potential to introduce competition that would be more likely to facilitate dynamic efficiency gains, we also include consideration of the extent of added value to which those gains may be applied, in each of the transmission functions we identify above.

In broad terms, we approach this question applying the presumption that competition in relation to solutions, and the building of transmission assets, may have the greatest potential to benefit consumers in the long run. In contrast, the operation of transmission most likely has the least scope for value adding innovation, while the financing function would seem to fall somewhere in between these two ends of the spectrum.

2.2 The rent-productivity efficiency spectrum

The economic theory underpinning incentive regulation of the providers of monopoly services acknowledges the existence of a trade-off between

- on the one hand, the level of productive efficiency attained; and
- on the other hand, the cost of any incentive payment that must be made to attain greater levels of productive efficiency.

The need to make such incentive payments amounts to a form of ‘economic rent’, ie, an amount over and above that necessary to secure production had the relevant service been provided in a workably competitive market. By ‘economic rent’, we are referring to an amount of profit that the service provider earns, over and above its economic costs (including the cost of remunerating capital).

This trade-off arises because, to harness economic incentives to achieve productive efficiencies, a regulator must offer service providers the prospect of increased profit to reward reductions in costs. In concept, this approach mimics the outcomes of workably competitive markets, in which a firm that successfully reduces cost (without compromising on quality) can expect a commensurate increase in profit.[9]

Figure 2.1 illustrates this efficiency-rent spectrum from a conceptual perspective. It shows that the cost of a transmission project declines (indicated by the teal line) as the size of the incentive payment made to the service provider in the form of economic rent (indicated by the red line) increases.

[9] However, this increase in profit is unlikely to be permanent, since all firms in a workably competitive market face similar incentives to reduce costs, ultimately influencing market price.

Figure 2.1: Illustration of the efficiency-rent spectrum

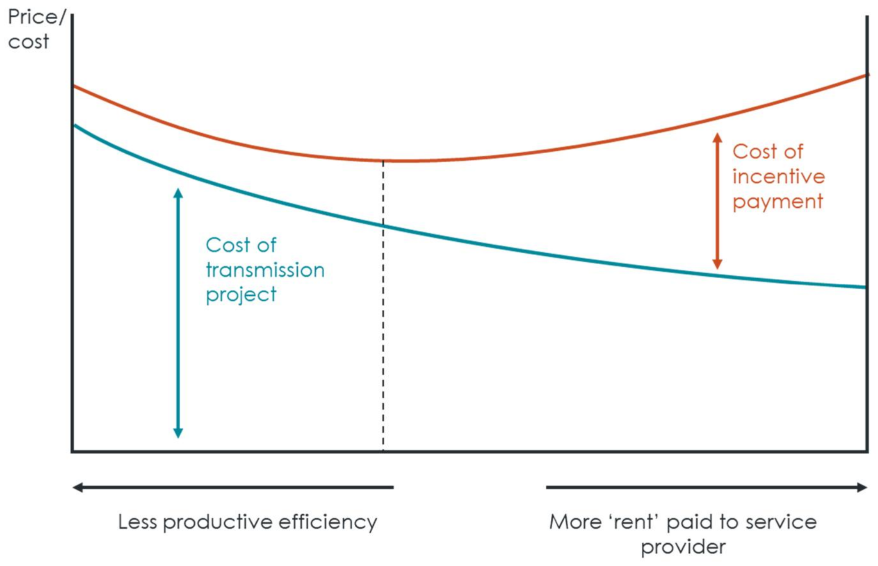


Figure 2.1 indicates with a vertical dashed line the point at which the total cost to the consumer from delivering the transmission project is minimised. This represents the optimal trade-off between the cost of the transmission project and the cost of the incentive payment made to the service provider. This could also be described as the allocatively efficient point on the efficiency-rent spectrum.

We have drawn figure 2.1 to show a mid-point solution to this trade-off. Allocative efficiency is achieved even though the transmission project could be delivered at lower cost, because to achieve this lower cost would require an even greater incentive payment to the service provider.

However, in some circumstances it may also be possible for there to be close to a 'corner solution', ie, allocative efficiency is achieved at either:

- the least productive efficiency, because the cost of incentivising improvement in productive efficiency is very high; or
- the greatest productive efficiency, because the cost of incentivising improvement in productive efficiency is very low.

It is important to acknowledge that the efficiency-rent spectrum identified above holds a number of factors constant – in particular, risk, information and competition. The existence of the trade-off we depict in figure 2.1 does not imply that greater productive efficiencies are not able to be achieved with the same or a lower incentive payment.

Rather, the potential for optimising this trade-off is likely to turn on both the contextual considerations and regulatory/competition options that are the focus of our report. For example:

- an increase in the risk associated with the provision of services would be likely to increase the incentive payment that a service provider would require to provide the services;
- an increase in information available to the regulator might mean that a more accurate assessment of costs could be performed, which would be expected to reduce the cost of the incentive payment that a service provider might expect to receive; or
- an increase in competition for procurement of transmission may also be able to spur service providers to achieve productive efficiencies with lower incentive payments than would be necessary in a less competitive environment.

The existence of contextual considerations has implications for the way in which we present one set of opportunities for optimising this trade-off, in section 5 below, in which we discuss potential options for introducing competitive tension to the procurement of large, discrete transmission projects. By way of example, those such contextual considerations entail the extent to which a particular transmission project may be physically separate from an incumbent TNSP's network, or the extent to which the meeting of a particular need may be apt for an innovative, non-network solution.

2.2.1 Cost-plus approaches

At one end of the spectrum of regulatory approaches (the left hand side of figure 2.1) lie 'cost of service' methods in which the regulator compensates the service provider for its incurred costs, including a regulated return on capital. This approach is often referred to as 'rate of return' regulation, traditionally applied in the United States.[10]

If a regulator can perfectly observe both costs and opportunity costs, such an approach offers no prospect of economic rent to the service provider. However, it also entails few or no incentives for the service provider to seek productive efficiencies, ie, a regulated service provider may be largely indifferent as to whether to increase or reduce costs.

In practice, a regulator cannot directly observe the rate of return that a service provider requires for its investments. This leaves open the prospect that the allowed rate of return might be set at a level that is either too high or too low.

Setting an allowed rate of return that is too high gives rise to the long held Averch-Johnson effect,[11] ie, a firm faces incentives to spend more than efficient levels so as to be able to recover this rate of return from consumers. This effect is often referred to as 'gold plating'. On the other hand, setting the allowed rate of return too low may not provide the regulated service provider sufficient incentives to undertake investments that would otherwise contribute net benefits to society.

2.2.2 Benchmarking and competitive procurement

At the opposite end of the spectrum from cost of service approaches are regulatory mechanisms (at the right hand side of figure 2.1) that determine prices or revenues without explicit regard to costs incurred. Examples of approaches at this end of the spectrum might include some form of yardstick or benchmarking approach, or competitive procurement, where the price is not set by reference to the costs of the regulated service provider, but rather by reference to the costs of similar businesses (in the case of benchmarking) or the willingness to supply by competitors (in the case of competitive procurement).

As a matter of principle, these approaches could be expected to provide much stronger incentives for the service provider to seek productive efficiencies. The service provider would be able to either:

- retain these efficiencies as increased profits until similar efficiencies are achieved by other businesses; or
- use these efficiencies to reduce its tender offer and increase the likelihood it will be selected to undertake the transmission investment.

The level of economic rent potentially available to the service provider (and needing to be paid by customers) under this approach would likely depend upon the effectiveness of benchmarking and competitive procurement. For example, confidence that the incentive payment would be low will be increased where:

- the regulator is able to draw upon a range of directly comparable projects carried out by directly comparable firms to inform the determination of efficient cost, such that the information asymmetry between the regulator and the firm is narrowed; or
- competition to provide the services is effective, such that it would be reasonable to assume that the outcomes of competitive tenders to procure transmission services would give rise to revenues and prices that would reflect efficient costs.

[10] However, regulation as practices in the United States is not purely 'cost-plus', since nominal prices are only ever updated when a firm seeks approval for an increase, and not all expenditure is necessarily counted when estimating the rate of return, ie, all capital expenditure is subject to a used and useful test, and potentially also to efficiency assessment. The result is that even under 'rate of return' regulation, various forms of incentive arise, some positive, and others not.

[11] First identified by Averch, H and Johnson, L, *Behavior of the firm under regulatory constraint*, American Economic Review, 52(5), 1962, pp 1052-1069.

We note that a reduction in the asymmetry of information can assist a regulator to reduce the size of the incentive payment in any setting in which the costs of the service provider are subject to a form of administrative assessment, such as under incentive regulation (discussed below).

It is important to note that benchmarking and/or competitive procurement-focused approaches do not allow direct controls on the economic rent that can be earned by the service provider. Rather, they indirectly affect the level of economic rent by reference to the productive efficiency of other providers and/or the level of competition in the provision of transmission investments. This leaves open the prospect that, in some circumstances, benchmarking and/or competitive procurement approaches may allow the service provider to earn substantial levels of rent, particularly in circumstances in which it is very efficient or faces relatively weak competition.

2.2.3 Incentive regulation

Incentive regulation, such as that applied by the AER for TNSPs in the NEM, is understood to fall between the ends of the spectrum depicted in figure 2.1 above. The modern approach to incentive regulation was initially devised by Professor Stephen Littlechild as the 'RPI – X' framework, in which prices were allowed to follow the rate of retail price inflation with an adjustment to take into account improvements in productive efficiency.[12] The original Littlechild paper – in relation to the price regulation of British Telecommunications – never contemplated the need for the X factor to be reset, or for that reset to be undertaken by reference to costs. However, recognition of the necessity of cost-based resets of ex ante price controls is now almost ubiquitous and underpins the approach to incentive regulation applied by the AER to TNSPs in the NEM.

Relative to a pure cost of service approach, incentive regulation reduces the frequency with which prices are realigned to actual costs, providing periods over which the service provider can strive to achieve productive efficiencies and to retain some of their benefits. The approach generally involves the forecasting of costs over a defined regulatory control period, and the determination of a maximum revenue allowance that takes account of the efficiencies achieved over the regulatory control period prior.

Through this approach, productive efficiencies achieved by the service provider give rise to long term benefits to consumers. Although the service provider retains the benefit of these efficiencies during the regulatory control period, at the regulatory reset forecast expenditures are re-based to reflect changes in actual costs and the productive efficiencies are shared with consumers in the form of lower revenues and lower prices.

Incentive regulation is generally held to achieve increased levels of productive efficiency, relative to a pure cost of service approach, principally on account of the incentives that it offers the service provider to reduce its costs. Beesley and Littlechild outline the counter argument against the efficiencies claimed to be achieved under RPI – X, which includes that:[13]

- the level of X must be set and repeatedly adjusted to manage political pressures that would arise from both consumers and regulated businesses if prices move out of line with costs;
- the resetting of X will require the provision of guidelines setting out the principles that would govern this process; and
- the revealed link between lower costs and reductions in prices will negate the incentives that the process seeks to provide.

2.3 Allocation of risk

Inherent to the undertaking of any major capital investment is the presence of risk. Although there may be options to mitigate risk, it cannot be entirely

[12] Littlechild, S, *Regulation of British Telecommunications' profitability*, Department of Industry, London, 1983.

[13] Beesley, M E and Littlechild, S, *The Regulation of privatized monopolies in the United Kingdom*, RAND Journal of Economics, 20(3), 1989.

eliminated. However, there may often be choices for managing and allocating risks between parties.

The AER has previously stated that:[14]

> The fundamental regulatory policy principle is one of efficient risk allocation: the risk should be allocated to the entity best placed to manage the risk.

This guiding principle is consistent with that described by the Commonwealth in its national public private partnership guidelines, which explain it by reference to the underpinning economic principle, ie:[15]

> To achieve value for money, risks are allocated to the party best able to manage them. This ensures that the cost of managing risk is minimised on a whole-of-life and whole-of-project basis.

As a matter of principle, both productive and allocative efficiency will be promoted where risks are allocated to the party that is best placed to manage them.

2.3.1 Regulation as a long term contract

Economic regulation is sometimes considered to be a special case example of long term contractual commitments that are often established between service providers and customers so as to underpin the construction of significant infrastructure.

Allocation of risk is central to the establishment of long term contracts. Such contracts help to overcome the 'hold up' problem that may be faced by both service providers and customers, whereby relationship-specific investments run the risk of being expropriated by the other party. Key risks that might be allocated in such contracts include:

- the risk that the costs associated with implementing and operating the investment vary from those expected when the contract was formed; and
- the risk that the demand that drives the revenues for the investment varies from that expected when the contract was formed.

By way of example, in Australia's gas pipeline sector, long term contracts are frequently agreed to underwrite the construction of new gas transmission pipelines. A common feature of these agreements is a fixed unit price for 'firm service' (or capacity). This feature reflects an arrangement that:

- passes the risk of cost overruns onto the service provider, since prices are fixed and cannot be renegotiated over the term of the agreement; and
- passes the risk of variations in demand onto the customer, since contracted capacity is fixed and cannot be renegotiated over the term of the agreement.

These are also key risks that are allocated – either explicitly or implicitly – within the regulatory framework that applies to TNSPs. It follows that an important consideration in relation to any changes to the economic regulation of large transmission projects considers the current allocation of risks for these projects under the framework, and how these risks might be affected under alternative options.

2.3.2 Regulatory compensation for risk

One of the difficulties of allocating risks in a regulatory environment is that determining the level of compensation consistent with this allocation is not a straightforward task. Businesses engaged in negotiating the terms of a contract can gauge their respective willingness to accept risk and reflect the allocation of risk in agreed terms and conditions. However, the regulatory

[14] AER, *Powerlink nominated cost pass through events: decision*, March 2013, p 12.

[15] Department of Infrastructure and Regional Development, *National public private partnership guidelines: overview*, December 2008, p 33.

tools used to compensate for risk are often not capable of distinguishing between different levels of risk to which a TNSP may be exposed.

By way of example, both Australia and New Zealand have recently made changes to the form of control for regulated electricity distribution network businesses – shifting from:

- a weighted average price cap approach, which determines prices based upon a forecast level of volumes and does not revisit these prices, exposing the service provider to a degree of volume forecasting risk; to
- a revenue cap approach, which determines prices based upon a forecast level of volumes and uses an overs-and-unders account to ensure that variance from these forecasts do not affect present value revenues.

From first principles consideration, a revenue cap approach appears to allocate less risk to the service provider and more to customers. However, both the AER and the New Zealand Commerce Commission were unable to find clear evidence to quantify this difference in risk and to make consequential changes in compensation for risk to service providers.[16]

2.3.3 Efficient allocation of risk

The allocation of risk is likely to affect the incentives of service providers to manage risk, including through how they forecast and incur costs, with these incentives also likely to differ when the risk allocation is considered from ex-ante and ex-post perspectives.

By way of example, figure 2.2 below illustrates the effect of risk allocation on ex-ante cost estimates and ex-post outturn costs. It shows that, as the customer bears more of the risk of project delivery, then:

- the required return for the project reduces, since the TNSP is exposed to less risk; and
- the forecast cost of the project reduces, since the TNSP becomes less exposed to the risk of cost overruns.

When the TNSP bears all the risk of cost overruns, it is likely to put forward cost estimates that include an implicit allowance for these risks, because it will earn economic rent from over-performance and face commensurate penalties for under-performance. When consumers bear all these risks, no such incentive prevails. These effects are presented by the grey line in figure 2.2 below.

By comparison, the outturn level of cost achieved by the TNSP is likely to increase as more risks are transferred onto consumers. In other words, where TNSPs bear all the consequences of cost overrun and all the benefits of productive efficiencies then they are likely to face strong incentives to minimise costs, consistent with the discussion at 2.2 above. Conversely, where these risks are placed with consumers, TNSPs will have less incentive to achieve efficient levels of costs and higher levels of outturn costs can be expected. This effect is demonstrated by the teal line in figure 2.2 below.

Depending on the allocation of risks between TNSPs and customers, the costs recovered from consumers can conceptually be thought of as falling between estimated and outturn costs. Conceptually, this suggests that there could be an allocation of risks at which the recovery of costs from consumers would be minimised. This is shown by the red line in figure 2.2 below line, with the point of minimum recovery indicated with a dashed vertical line.

[16] AER, *Rate of return instrument: explanatory statement*, December 2018, p 56; and Commerce Commision, *Input methodologies review draft decisions – Topic 4: Cost of capital issues*, 16 June 2016, pp 77-80.

Figure 2.2: Illustration of effect of risk allocation on ex-ante costs

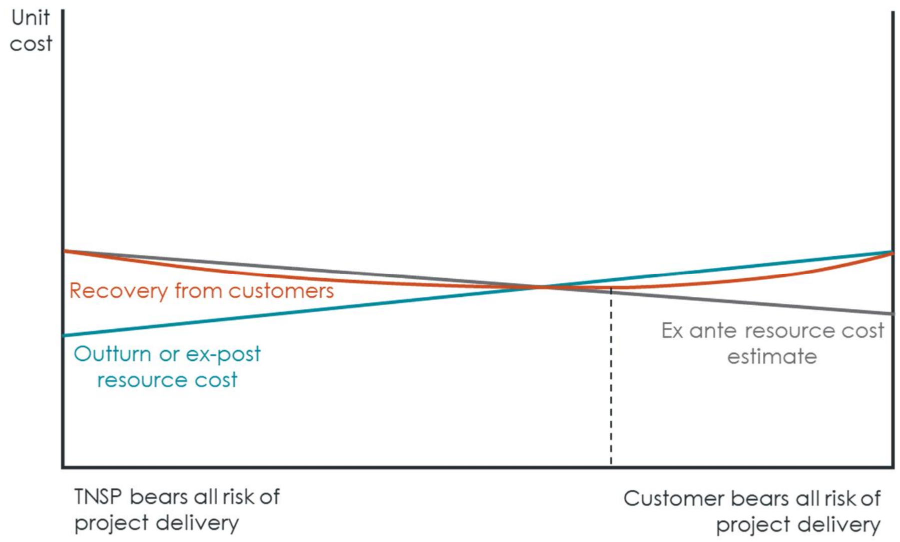


Figure 2.2 illustrates that the long term interests of consumers are best promoted in circumstances in which the allocation of risks strikes an appropriate balance in managing the incentives of TNSPs and sharing the benefits of efficiencies with consumers. This is not necessarily (and indeed is unlikely to be) consistent with the TNSP bearing all risks of project delivery.

As a practical matter, it is also important to consider appetite of the various parties to the explicit or implied allocation of risk – a factor that is held constant in figure 2.2 above.

Regulated TNSPs tend to be risk-averse businesses, attracting investors looking for relatively low and stable returns. This is reflected in the approach brought to bear by the AER in determining the return on equity for regulated businesses, which assumes a regulated energy network businesses is low risk because of:[17]

> …its monopoly position and NER and NGR provisions that are likely to mitigate various systematic and non-systematic risks (including demand risk).

As a matter of principle, it is unlikely to be attractive for businesses with this profile to take on greater levels of risk associated with large, discrete transmission projects. If the service provider has a fundamentally risk averse profile, it will likely require higher compensation for additional risk. In such circumstances the long term interests of consumers may be better promoted by allocating a greater degree of risk to consumers than would be the case if the service provider were less risk averse.

This consideration is likely to be important when considering what can be achieved with existing TNSPs, as against the potential for introducing more risk-seeking entrants into the industry by exposing the procurement of transmission investments to greater competition.

2.4 Time and complexity

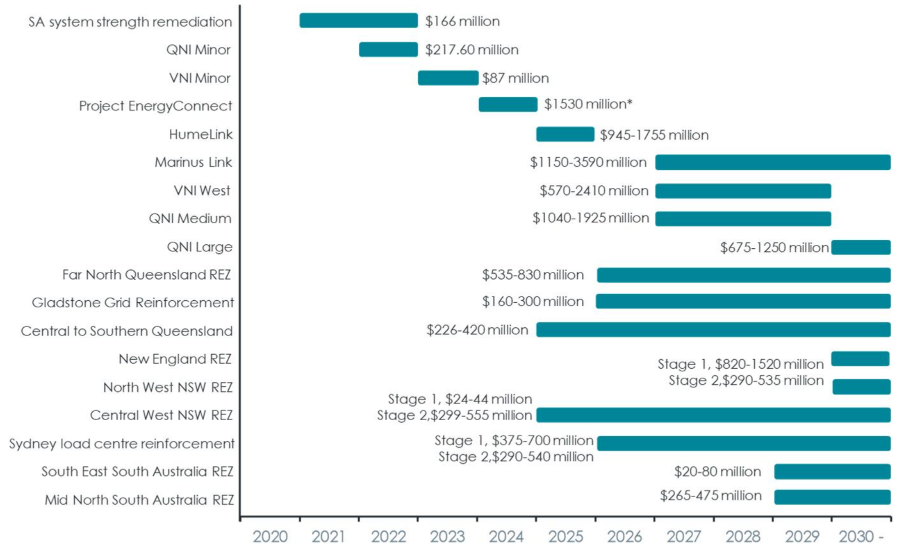
The pursuit of any changes to the economic regulatory framework for the delivery of electricity transmission projects must contend with a further trade-off in relation to the time that would be required to implement a proposed solution. In turn, this will be governed by the complexity of any change that is adopted.

[17] AER, *Rate of return instrument: explanatory statement*, December 2018, pp 145-146.

2.4.1 Expenditure on ISP projects

Expenditure on ISP projects is expected to be spread over the next two decades. The distribution of possible project timing, with focus on the coming ten years, is highlighted in figure 2.3 below.

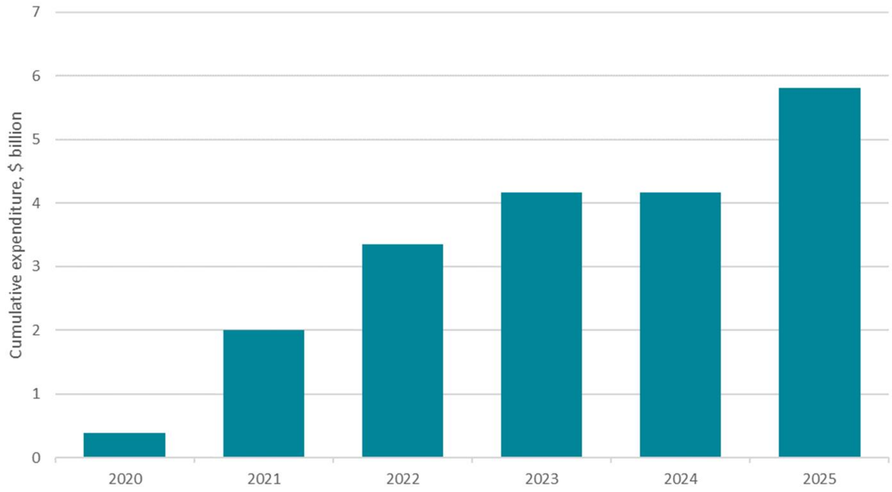
Figure 2.3: AEMO draft ISP indicative timing ranges



Source: AEMO's Draft 2020 ISP and project releases. The Victoria specific 'Western Victoria transmission augmentation' project has been omitted. Similarly, 'Marinus Link "shovel-ready" works' has been omitted.

A substantial proportion of these projects is forecast to be undertaken in the near term. For example, figure 2.4 shows that over $8 billion is expected to be spent on ISP projects by 2025.

Figure 2.4: Profile of cumulative ISP transmission expenditure



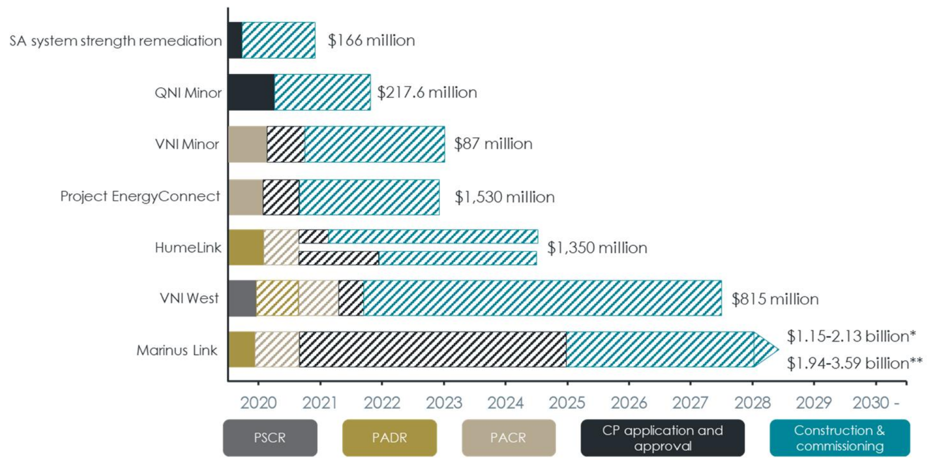
Note: Expenditure grouped by financial years. This figure accounts for investment in the following: SA system strength remediation, QNI Minor, VNI Minor, Project EnergyConnect, HumeLink, VNI West, and Marinus Link. Expenditure is added at the date at which the project's contingent project application is estimated to be approved.

Giving substance to this forecast, a number of ISP projects are currently going through the regulatory assessment process or have already been implemented. For example:

- 'SA system strength remediation' and 'QNI Minor' have been approved by the AER and are currently undergoing construction;
- 'VNI Minor' and 'Project EnergyConnect' are currently being reviewed by the AER as contingent projects (or have progressed from the RIT-T assessment); and
- 'HumeLink', 'VNI West' and 'Marinus Link' are currently subject to a RIT-T assessment.

Figure 2.5 below highlights the current stage and anticipated timing of near-term ISP projects. This information is relevant for the potential for any of the reform options canvassed in sections 4 and 5 to apply to the contemplated program of new transmission projects. For example, if a contingent project application has been approved, it may be reasonable to assume that regulatory reforms introduced subsequently may have limited effect on the delivery of that project.

Figure 2.5: Anticipated and actual timing of ISP projects

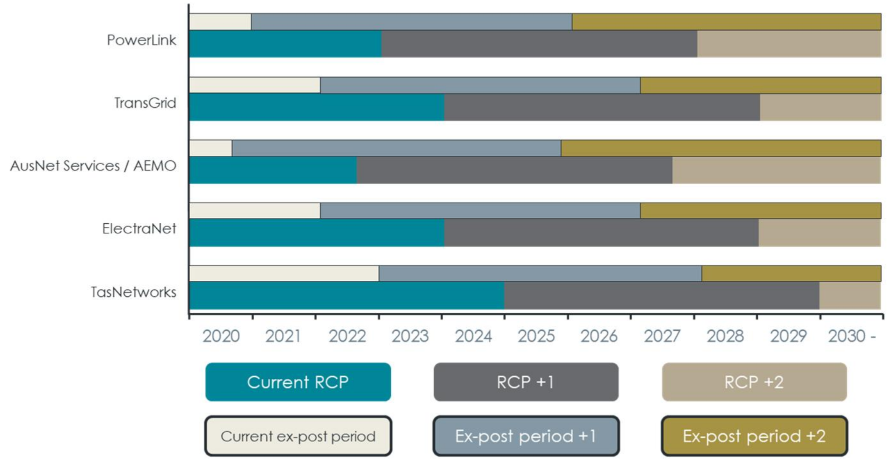


Note: Anticipated timing is subject to change. Shaded boxes represent steps that are yet to occur and so reflect forecasts. Forecasts are based on AER data, TNSP project timings and AEMO's Draft 2020 ISP. *(*) refers to Marinus Link Option 1, and (**) refers to Marinus Link Option 2.* The Victoria specific 'Western Victoria transmission augmentation' project has been omitted.

A further consideration relevant to determining whether an option will apply to a given project is its alignment with the relevant regulatory control period.

By way of example, the AER's power to undertake an ex-post review of cost affects all capital expenditure specified within a five year regulatory control period. A policy response that seeks to modify how ex-post review occurs, that applies only prospectively, would therefore influence the delivery of projects approved from the beginning of the next regulatory control period. The timing of regulatory control periods varies across TNSPs, and is illustrated in figure 2.6 below.

Figure 2.6: Regulatory control periods



Note: Powerlink's current regulatory control period spans from 1 July 2017 to 30 June 2022 TransGrid's current regulatory control period spans from 1 July 2018 to 30 June 2023, AusNet Services / AEMO's current regulatory control period spans from 1 April 2017 to 31 March 2022, ElectraNet's current regulatory control period spans from 1 July 2018 to 30 June 2023 and TasNetworks current regulatory control period spans from 1 July 2019 to 30 June 2024. The ex-post exclusion period covers years 1, 2 and 3 of the regulatory control period just ending and years 4 and 5 of the regulatory control period preceding that.

2.4.2 Potential trade-off between time and efficacy

The effect of this wave of investment is such that, the longer it takes to implement changes to the economic regulation of large transmission projects, the fewer such projects will be subject to the changed arrangements.

This may not necessarily give rise to a trade-off. The most desirable change to the framework for economic regulation to address the circumstances of large, discrete transmission projects may be a *de minimis* change that can be implemented rapidly and would apply to all future projects.

However, there is also the potential for such a trade-off between one reform option and another. Consider a comparison between two reforms, ie:

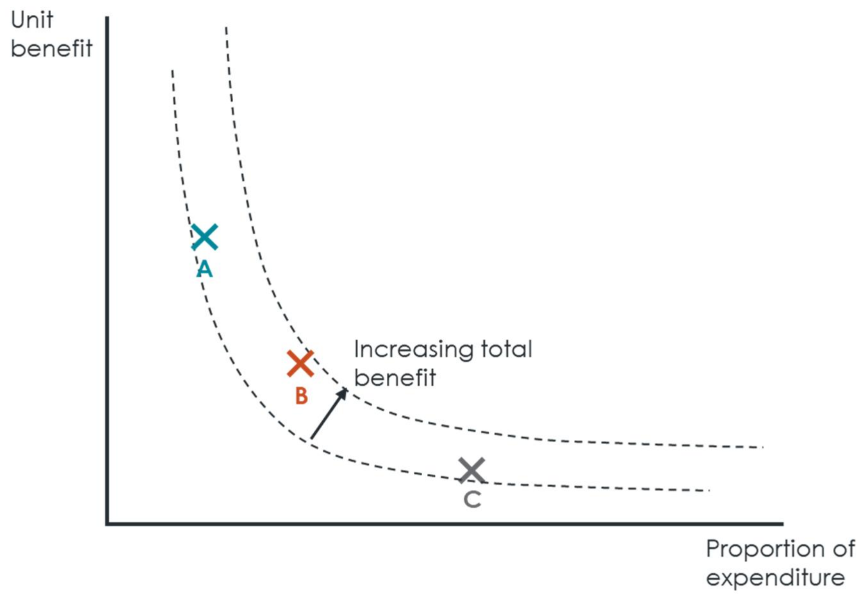
- one that gives rise to substantial benefits (say, expressed on a unitised basis) but which apply to fewer transmission projects due to a long implementation timeframe; and
- another that gives rise to fewer unitised benefits, which apply to more transmission projects because it has a short implementation timeframe.

This may give rise to a trade-off as between introducing the policy that gives rise to the greatest benefit per dollar of expenditure as against the policy that will affect the greatest quantum of anticipated project expenditure.

For example, figure 2.7 below sets out a stylised comparison of three projects assessed by reference to the unit benefit that each delivers, as against the proportion of expenditure to which each applies. Overlaid on the figure are curves representing a constant level of total benefit.

The figure shows that three reforms – A, B and C – each offer a different balance in terms of unit benefit and the proportion of expenditure to which each applies. However, on a standalone basis, reform B offers the greatest total benefit – being the product of these two factors.

Figure 2.7: Illustration of the time-efficacy trade-off



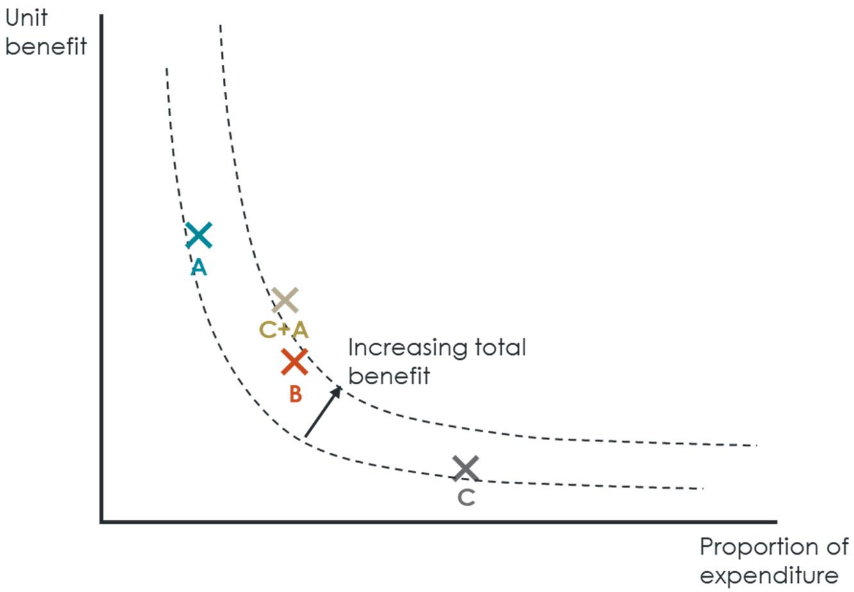
2.4.3 Implications for sequencing reforms

Although figure 2.7 shows that policy B gives rise to the greatest total benefit as assessed on a standalone basis, this approach by itself may not identify the best package of reforms. This is because it does not take into account the potential that reforms may be sequenced so as:

- initially, to introduce reforms that would require less lead time to introduce and would therefore apply to a larger proportion of relevant transmission expenditure; and
- subsequently, to introduce more far reaching reforms that would require a longer period to formulate but would have a greater benefit once they take effect.

For example, by reference to figure 2.7, it may be the case that reform B is incompatible with the other reforms, but that reforms A and C could be implemented sequentially, beginning with reform C and subsequently introducing reform A. This sequenced reform might present a more attractive option than reform B, as indicated in figure 2.8 below.

Figure 2.8: Illustration of sequencing reforms



The possibility of sequencing reforms may be of particular relevance in the context of the regulatory arrangements applying to large, discrete transmission projects. We explain in section 5 that the introduction of competitive tension to the procurement of transmission projects appears to have been successful in other jurisdictions. However, such changes would require revisions to the National Electricity Law (NEL) with substantial lead time. Until they can be realised, it may be possible to introduce less far-reaching reforms in the near term – such as those canvassed in section 4 – that would seek to address the issues raised by large, discrete transmission investments by other means.

It is important to note that sequencing reforms may impose additional administration costs on the AER, the TNSP and other stakeholders. These costs must also be taken into account when assessing potential reform options against each other. We discuss administration costs in more detail at section 2.5 below.

2.4.4 Factors that influence the time required for reform

Key factors that are likely to influence the amount of time that would be required to implement a specific reform may include:

- the complexity associated with the reform; and
- the degree of regulatory and legal change that will be required to implement the reform.

The complexity associated with a reform cannot easily be quantified but can be assessed by reference to the extent that the roles and functions of parties within the economic regulation of transmission might change by consequence of the proposed reform. Although these matters may also drive administration costs, complexity is driven by a divergence from the status quo that requires a period over which new processes are bedded down. Sometimes, the length of this period can lead to the failure of reform, if it means that the potential benefits are not realised in time to manage political pressures.

The degree of regulatory and legal change also influences the timeframes and costs associated with reform. From the perspective of the AER, it is reasonable to consider three scenarios that give rise to different levels of time and complexity, being:

- changes within the discretion of the AER, such as the making of guidelines or decision-making during regulatory assessments within the boundaries prescribed by the National Electricity Rules (NER) and NEL;
- changes to the NER, which would require the submission of a rule change application to the Australian Energy Market Commission (AEMC) and consequential consultation on that proposal; and
- changes to the NEL, which would require the agreement of the Council of Australian Governments (COAG) Energy Council.

Although these scenarios are set out in order of increasing time and complexity, they are not mutually exclusive. For example, it is often the case that changes to the NER require new decisions to be made by the AER, or that actions by the AEMC and/or the AER may inform or follow from a change to the NEL.

Further, overlaying each of these three scenarios is the AER's current review process as to whether the existing regulatory framework remains appropriate for large, discrete, non-recurrent transmission investments.

Figure 2.9 summarises our framework for estimating the implementation timeframe of changes by reference to the scenarios defined above. As can be seen, our framework assumes:

- a six-month timeframe for the AER's current review of the regulatory framework for large transmission investments;[18]
- a six-to-12-month timeframe for a rule change process, based on the AEMC's rule change guidelines and influenced by the complexity of the proposed change;
- a 12-to-18-month timeframe for law changes, reflecting the generally biannual nature of COAG Energy Council as well as the timeframes for recent law changes; and
- a 12-month timeframe for the AER to implement changes within the discretion of the AER, reflecting the timeframe taken by the AER to implement new expenditure incentives in response to the better regulation reforms.

We note that these timeframes are only indicative. There is no certainty associated with the pace of reform, and this uncertainty increases with the number of decision-makers that are required to participate in the process.

Figure 2.9: Overview of implementation timeframe assumptions

2.5 Administrative costs

To the extent that changes are made to the economic regulatory arrangements for TNSPs to account for the specific circumstances of large, discrete transmission projects, there are likely to be upfront costs associated with implementing and bedding down reforms. Further, regardless of any such

[18] We note that we have adopted this assumption for the purposes of our assessment. We understand that AER is yet to finalise its timeframe to reach a final policy position.

changes, there will always be ongoing costs associated with administering the arrangements that are in place.

In this report, we refer to these costs as 'administrative costs'. This does not imply that they are incurred only by administrative agencies, like the AER. Rather, we use the term to refer to the reform and transactional costs associated with any approach to regulating large, discrete transmission projects. These could include costs incurred by TNSPs or other parties to engage with the regulatory process.

By way of example, under the current arrangements for assessing ISP investments in the NEM, the AER assesses whether these are prudent and efficient on an ex-ante basis during its contingent project process. This is a costly exercise that requires a careful assessment of the project's expected costs and the benchmarking of these against industry standard engineering approaches and unit costs.

Although these costs could potentially be avoided if the project were opened up to competitive tender, such a process would itself be a costly exercise for the AER, the TNSP and its potential competitors. Costs associated with this arrangement might include:

- the costs required to specify (to an appropriate degree) the need or investment for which solutions are sought;
- the costs required to manage a tender process and assess the quality of individual tenders;
- the costs for tenderers to engage in the tender process, including the preparation of offers and coordination with suppliers and the tender manager; and
- the costs to supervise the successful tenderer in its planning, implementation and delivery of the investment.

Some of these costs must also be incurred under the existing arrangements and may therefore not be incremental to the introduction of a competitive tender process. However, it remains important to undertake a careful assessment of these costs.

Further, it is important to note that making reforms to any arrangements always results in one-off costs that will not be incurred under the status quo. These include 'upfront' costs, such as the costs associated with consultation on and implementation of a reform option. They also include any one-off effects may extend beyond the immediate term, including the costs associated with new arrangements 'bedding in'.

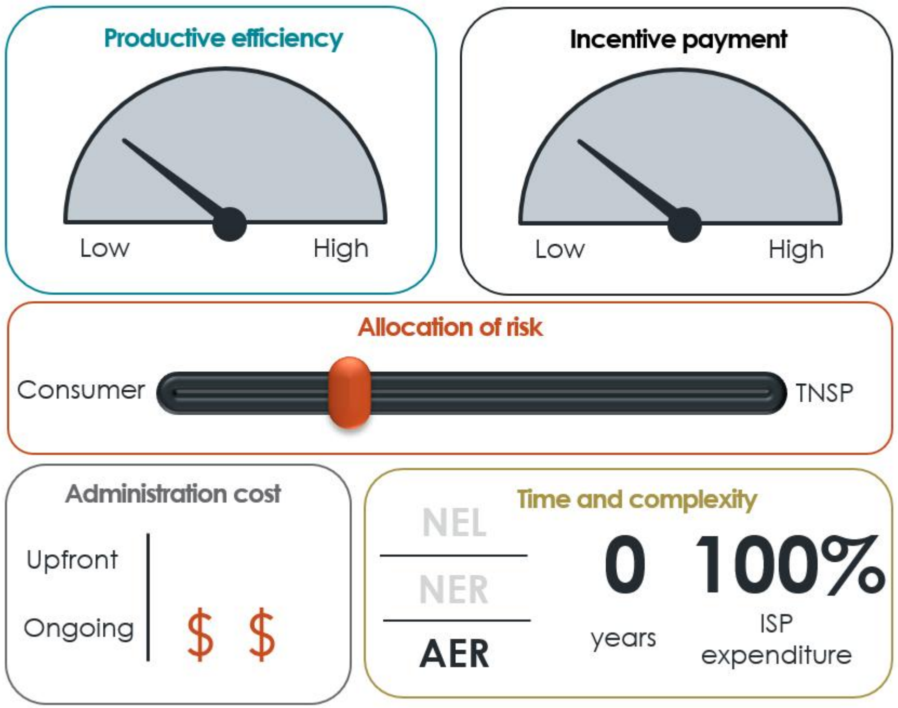
The existence of these one-off costs associated with change means that there must always be a case for change – it should generally not be taken as the default option.

2.6 Assessment scorecard

In sections 4 and 5 we apply the framework that we introduce in this section to assess and compare the existing economic regulation of large transmission investments as against alternative options.

Figure 2.10 below illustrates the assessment scorecard that we use to communicate high level insights about existing and alternative policy options. We explain each of the facets displayed in this figure below.

Figure 2.10: Example of assessment scorecard



The top two facets of figure 2.10 (with the teal and black borders) use meter displays to indicate the relative position of the policy option within the efficiency-rent spectrum that we discuss at section 2.2 above. Options with:

- low rent and low productive efficiency are indicated with the arrow pointing towards the left hand side of the meters; and
- high rent and high productive efficiency are indicated with the arrow pointing towards the right hand side of the meters.

We note in section 2.2 that the efficiency-rent spectrum holds a number of factors constant, notably risk, information and competition. Since most of the options that we present in sections 4 and 5 of this report entail changes to one or more of these factors, our scorecard depicts the two components of the trade-off separately. This ensures that the scorecard can capture a wider range of outcomes, such as where a lower incentive payment could be achieved for the same level of productive efficiency.

The middle facet of figure 2.10 (with the red border) uses a slider bar to indicate the relative allocation of risk resulting from the option. To keep this comparison simple, we show only the allocation of risk between two parties, being the consumer and the TNSP. The figure indicates:

- high-powered incentives when the slider is at the far right of the scale, such that all risks are allocated to the TNSP; and
- low-powered incentives when the slider is at the far left of the scale, such that all risks are allocated to the consumer.

The bottom-left facet of figure 2.10 (with the grey border) illustrates the relative scale of upfront and ongoing administration costs associated with the option. Each is given a rating from zero to three dollar signs. Options that are already in place require no new upfront costs and so are given a rating of zero in that dimension.

The bottom-right facet of figure 2.10 (with the brown border) illustrates the time, effect and complexity of the option. In the middle of the facet is an estimate of the number of years that will be required for the option to take effect. The figure to the right of that indicates the proportion of ISP expenditure that would be affected by the option, given the time to implementation. On the left hand side of the facet, the bolded text indicates the degree of regulatory change that the option would require, including:

- changes to the exercise of the AER's discretion through guidelines or decision making powers;
- changes to the NER through the AEMC's rule making process; or

- changes to the NEL through the COAG Energy Council.

3. Existing regulatory framework for procuring transmission investments

This section describes the existing regulatory framework within which transmission investments are procured, with a particular focus on the means by which the large, discrete projects identified within the ISP are considered.

The ISP sets out AEMO's view of the means by which consumer needs in the NEM can be met at least cost, for the long term benefit of consumers, subject to technical and – also called the 'optimal development path'. It identifies a pipeline of large transmission projects or non-network options, which are either currently being progressed or will be progressed soon. The first ISP was published in 2018 and subsequent ISPs will be published every two years.

In order to make the ISP 'actionable', the COAG Energy Council, advised by the Energy Security Board (ESB), has made changes to streamline the regulatory processes for key ISP projects. These changes reflect the view that the ISP has effectively replaced steps that TNSPs would previously have taken to identify the need for a transmission network investment that should be considered in a subsequent cost-benefit analysis.

Despite substantial changes to the arrangements for planning in the NEM to cater for large transmission projects, the framework for addressing the remaining aspects of delivering these projects remains largely as it was prior to the ISP reforms, with minor changes to the RIT-T and the introduction of the AEMO feedback loop. Figure 3.1 below illustrates the key steps involved in delivering actionable ISP projects.

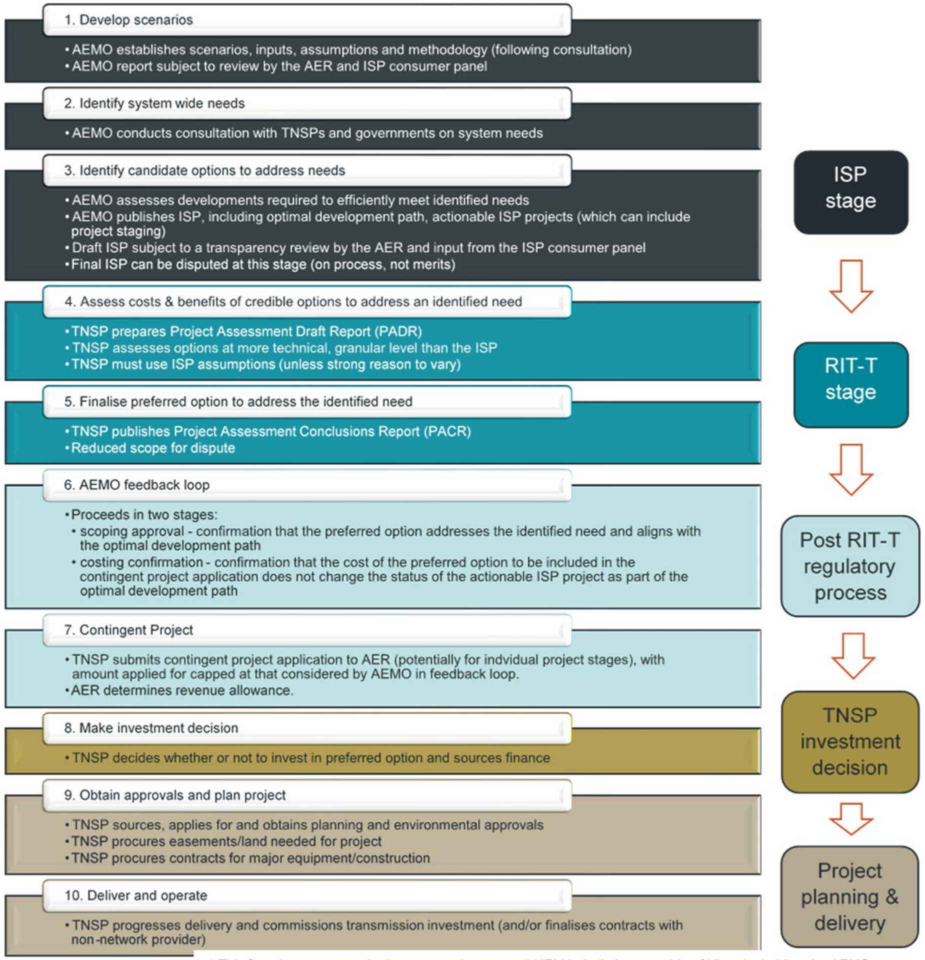
As the figure shows, ISP projects must satisfy a RIT-T assessment, the purpose of which is to undertake a cost-benefit analysis, which assesses the ISP credible option at a greater degree of detail, including engineering aspects, staging, refining estimates of costs and also considers alternative options.

The preferred option identified by the TNSP in the RIT-T process is then exposed to a 'feedback loop' assessment, whereby the TNSP must seek written advice from AEMO that:

- the RIT-T preferred option meets the identified need set out in the ISP; and
- the cost of the RIT-T preferred option does not change the project's status as part of the optimal development path.

The TNSP may seek to commence the contingent project process once these triggers have been satisfied. However, the TNSP is constrained to apply the contingent project process using no more than the cost of the RIT-T preferred option considered by AEMO during the feedback loop.

Figure 3.1: Key steps in the delivery of actionable ISP projects



This flowchart presents the key steps relevant to all NEM jurisdictions outside of Victoria. In Victoria, AEMO assumes the role of the TNSP in steps four, five and eight. Whether AEMO assumes the TNSP role in the post RIT-T regulatory process steps (six and seven) depends on whether the contestable procurement approach applies to the project in question.

Source: ESB, Converting the integrated system plan into action – consultation paper, May 2019, p21. (modified)

The actionable ISP framework provides a new means by which large transmission investments are planned and delivered in the NEM. Broadly speaking, the actionable ISP framework comprises four steps, ie:

- AEMO identifies investment needs and candidate options to address those needs through the ISP cost benefit analysis (CBA) process;
- TSNPs refine the preferred solution to a given need, performing a more granular CBA through the RIT-T process;
- incumbent TNSPs are allocated the right to build, own and operate the preferred solution and are responsible for all stages of project delivery; and
- the AER administers the regulatory framework to provide incentives to reveal efficient costs.

The remainder of this section describes these steps in greater detail.

3.1 AEMO develops the Integrated System Plan

Forecasting the needs of the transmission network relies on making assumptions about the future, which is inherently uncertain. This uncertainty is amplified in the context of the renewable generation transition, since there is imperfect information regarding many factors, such as:

- the timing of the retirement of coal-fired plants; and
- the rate of penetration of renewables.

AEMO's ISP plays an important role in mitigating these uncertainties. To this end, AEMO develops scenarios, inputs and assumptions to examine the future needs of the NEM's transmission network. Prior to publishing a draft ISP, AEMO is required to publish an inputs, assumptions and scenarios report. This process is consultative, meaning AEMO must engage with stakeholders and clearly justify its decision-making. Further, the ISP rules require that both the AER and the ISP consumer panel review the scenarios, inputs and assumptions report. The focus of these reviews is on the transparency with which the report has been developed, as well has whether stakeholder feedback has been adequately taken into account.

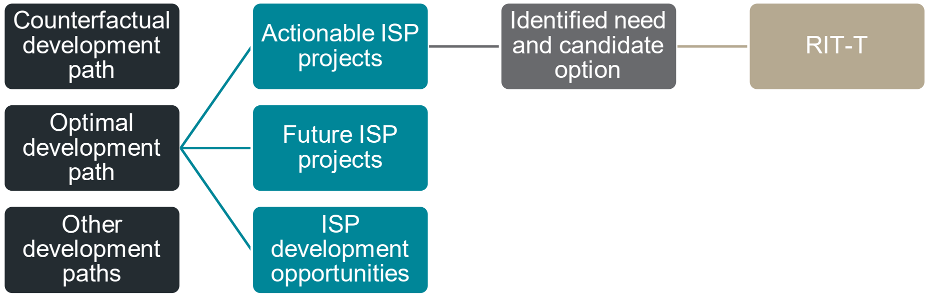
The scenarios, inputs and assumptions that are produced from this process form the basis of AEMO's assessment of the transmission network's needs through the ISP. These needs in turn shape the optimal development path.

The optimal development path is a roadmap that outlines a set of candidate options for transmission investments and other electricity supply chain investments that AEMO determines best meets the power system needs over a 20-year horizon. This optimal development path is informed by an assessment of augmentation options based on whether they contribute to the least cost market development pathway informed by a system-wide optimisation, and is chosen through a cost benefit analysis across different development path options. The ISP comprises three broad types of investments, ie:

- actionable ISP projects – where the project assessment draft report (PADR) is required within two years;
- future ISP projects – projects that are not yet actionable; and
- ISP development opportunities – other electricity supply chain investments such as renewable energy zone (REZ) generation opportunities.

Actionable ISP projects ultimately form the candidate options to address the short-term needs of the electricity network. To establish the optimal development path, AEMO considers the net market benefits of a range of possible development paths against a counterfactual development path, ie, the status quo where there are no new ISP projects. This process is summarised in figure 3.2 below.

Figure 3.2: Development of identified need and candidate options in the ISP



AEMO is afforded significant discretion as to the criteria it uses in making its determination. The ISP rules require the AER to provide flexibility to AEMO in its approach to scenario development, modelling and selection of the optimal development path in the AER's cost-benefit analysis guidelines. Although AEMO is required to consider the quantitative costs and benefits of various options, there is no obligation to adopt a probability weighted scenario analysis.

The purpose of this flexibility is to facilitate an approach that is conducive to supporting a more flexible and dynamic transmission planning framework in response to the rapidly changing energy sector. We note that the flexibility afforded to AEMO is balanced by requirements:

- to undertake extensive consultation;
- to be transparent in its reasoning; and
- to take into account key objectives – most significantly, the long-term interests of consumers.

3.2 TNSPs refine the preferred solution using the RIT-T

The actionable ISP framework significantly changes the existing application of the RIT-T. In particular, the ISP replaces the former first stage of a RIT-T – the project specification consultation report (PSCR), since the identified need is determined and the call for non-network options occurs in the ISP. This change means that the RIT-T for actionable ISP projects will consist of two reports, the:

- PADR; and
- project assessment conclusions report (PACR).

For each actionable ISP project, the ISP specifies a date by which the PADR should commence – providing more guidance to TNSPs and generators.

Despite these broad changes to the RIT-T framework, its application remains a requirement for TNSPs under the NER. The overall purpose of the RIT-T component of solution selection is to conduct a more detailed, technical analysis of the credible options for transmission investment – capitalising on the local knowledge of TNSPs.

ISP candidate options are required to be assessed as credible options in the RIT-T. Further, RIT-T proponents are required to use the inputs and assumptions used in the ISP (unless they demonstrate a reason why it is necessary to depart from those assumptions). Finally, RIT-T proponents may, but are not obliged to, consider other credible options not identified by AEMO. Under the AER's draft CBA guidelines, they are also required to assess non-network options flagged in the final ISP.

The actionable ISP framework also provides scope for TNSPs to apply a RIT-T to staged projects. The ESB has previously distinguished between:

- a staged RIT-T, which comprises:
  - an early works RIT-T – for more substantial preparatory works identified in the ISP as an actionable ISP project; and
  - an implementation RIT-T – for the subsequent works to complete the same actionable ISP project; and
- a full RIT-T – for the entire project.

These different types of RIT-Ts have not become defined concepts in the rules. However, the final ISP rules require that for each actionable ISP project, the ISP must specify whether it is a staged project. We understand that the AER's draft CBA guidelines will set out the RIT-T framework for staged projects in greater detail.

3.3 TNSPs are responsible for project delivery

Allocation of the right to build, own and operate transmission solutions in the NEM continues to be based on a de facto monopoly procurement approach. The location of the solution determines the incumbent TNSP to which responsibility for that solution falls. For assets such as interconnectors, the respective TNSPs will build, own and operate the relevant assets located in their geographic area in which their de facto monopoly applies.

Although TNSPs are required under the NER to undertake the RIT-T, the actionable ISP framework imposes no obligation on a TNSP to invest following a successful RIT-T and contingent project application.

If a TNSP decides to proceed with an investment, it is ultimately responsible for the project management and delivery of the investment throughout the entire investment process. Some of these responsibilities may be transferred to third parties through contracting arrangements. Although this process may vary between individual TNSPs, it typically involves procurement approaches that are tailored to the equipment or service being acquired. These procurement approaches include:

- competitive open tendering;
- tendering from panel suppliers; and
- pre-agreed supply agreements.

The exact procurement approach is dependent on the equipment and services being procured and the nature of the transmission investment. It follows that while competitive tension may be introduced at this step, the nature and extent of the competitive process adopted falls to the TNSP.

TNSPs are also responsible for the development of tender documents. Since the procurement of equipment and services can be highly technical in nature, TNSPs need to develop detailed specifications and tendering documents that are specific and fit for purpose. This process requires a high degree of expertise and knowledge of the transmission network.

Finally, TNSPs are also required to secure the easements or land for the transmission line, as well as the regulatory and environmental planning approvals.

3.4 AER administers incentive framework

The framework by which the AER regulates the revenues and prices of TNSPs is intended to promote the long term interests of consumers by providing incentives for TNSPs to reveal their efficient costs. Three important mechanisms that contribute to these incentives include:

- the means by which forecast capital expenditure is assessed and approved, either through the five year revenue proposal and determination process or through the contingent project process;
- the capital expenditure sharing scheme (CESS) by which TNSPs take on some of the risks of over-performance and under-performance against expenditure forecasts that would otherwise be placed on consumers; and
- the potential for *ex-post* review of capital expenditure through which the AER may exclude some or all of over-spending from the RAB, where it determines that this expenditure is not prudent or efficient.

[19] NER, cl 6A.4.2.

[20] NER, cl 6A.4.2(c)

We discuss these mechanisms in more detail below.

3.4.1 Ex-ante five year revenue cycle and contingent project process

TNSPs are regulated on an ex-ante basis, ie, the NER require the use of a revenue cap form of price control for prescribed transmission services.[19] For every regulatory control period, which must be at least five years in length,[20] the TNSP must submit a revenue determination that includes:

- the **estimated total revenue cap** for the regulatory control period, or the method for calculating that amount;
- the **annual building block revenue requirement** for each regulatory year of the regulatory control period, or the method for calculating that amount;
- the **amount of maximum allowed revenue** for each regulatory year of the regulatory control period or the method for calculating that amount; and
- the **RAB as at commencement** of the regulatory control period.

The regime provides each TNSP with a ‘bucket’ of forecast capital expenditure at the beginning of each regulatory control period, from which a TNSP is able to allocate this amount so as to meet quality requirements and seek out opportunities for productive efficiency gains.[21] Since TNSPs bear cost overruns and underruns, this bucket of costs also provides TNSPs with the opportunity to offset cost overruns on some projects with efficiencies achieved in relation to others.

Although the revenue cap is determined at the start of the regulatory control period, there are a number of mechanisms incorporated in the regulatory framework that address the risk that a TNSP may be required to spend more than its forecast capital expenditure during a regulatory control period due to

[21] More accurately, each TNSP is provided a return on capital and return of capital in relation to the ‘bucket’ of approved expenditure.

circumstances outside of its control. These include arrangements in relation to:

- **contingent projects** – specific arrangements to address major capital expenditure projects, where the timing or cost of the project is uncertain due to external factors;[22]
- **cost pass-through** – additional costs (or cost reductions) that occur during the regulatory control period, due to specific factors, such as any change in an externally imposed service standard obligation, where these exceed a materiality threshold; and[23]
- **capital expenditure reopener provisions** – where the network service provider faces a major increase in capital expenditure requirements due to factors that could not have been foreseen at the time of the determination.[24]

The capital expenditure and operating expenditure associated with a contingent project application is added to the RAB and revenue allowance after a specified trigger occurs. These costs:

- are subject to AEMO's feedback loop, which establishes a maximum allowed capital expenditure; and
- must be approved (and modified where appropriate) by the AER through the contingent project application process.

Approved capital and operating expenditure are subsequently incorporated into the revenue allowance the regulatory control period. As part of the feedback loop and contingent project application process, the estimates of capital expenditure and operating expenditure provided by the TNSP are subject to scrutiny. For example, in relation to contingent project capex, the AER assesses expenditure against the capital expenditure criteria.[25]

To enable the AER's assessment, TNSPs provide a range of information to the AER. For example, as part of its contingent project application for QNI minor, TransGrid provided:[26]

- capital expenditure, operating expenditure and PTRM models;
- forecast inputs and forecasting methodologies;
- costs of purchasing relevant assets;
- other inputs such as labour costs, engineering, procurement and design costs, costs of stakeholder engagement, land and environment, and the assumptions that underpin them; and
- process details such as tender evaluation criteria.

Once necessary information is obtained, the AER undertakes a 'bottom up' assessment of operating expenditure and capital expenditure, evaluating the appropriateness of TNSP assumptions using inhouse technical and engineering expertise and by comparing estimates with comparable projects. In instances where uncertainties remain, the AER may request further information.

3.4.2 Capital expenditure sharing scheme

The CESS is designed to reward TNSPs for efficient expenditure and share the benefits with consumers.

In broad terms, the CESS approximates efficiency gains and efficiency losses by calculating the difference between approved forecast and actual capital expenditure. It shares these gains or losses between TNSPs and consumers. Under the CESS, a service provider retains approximately 30 per cent of an under-spend or over-spend – so that for a one dollar saving in capital

[22] NER, cl 6A.8.

[23] NER, cl 6A.7.3.

[24] NER, cl 6A.7.1.

[25] NER, cl 6A.6.7(c)

[26] Refer to the TransGrid - QNI minor upgrade contingent project page of the AER's website, available: https://www.aer.gov.au/, accessed: 30 June 2020.

expenditure, the service provider keeps 30 cents of the benefit while consumers keep 70 cents of the benefit.

An important shortcoming of the CESS framework is that it is unable to distinguish between below forecast capital expenditure that arises from genuine efficiencies (ie, achieving the same outcome for less), as distinct from deferments of expenditure, changes in expenditure drivers and high capital expenditure forecasts.[27] These intrinsic challenges arising in relation to capital expenditure, which create an incentive for TNSPs to defer capital expenditure from one regulatory control period to the next, were recognised in the development of the CESS.[28] By way of recognition of these issues, the CESS model provides for the present value of deferred capital expenditure (both as to its value and timing) to be deducted from the cumulative under or overspend.

In the CESS guidelines, it is noted that to help consumers share the benefits from deferred capex, the AER will adjust CESS payments where a TNSP:[29]

> …has deferred capex in the current regulatory control period and:
>
> a. the amount of the deferred capex in the current regulatory control period is material, and
>
> b. the amount of the estimated underspend in capex in the current regulatory control period is material, and
>
> c. total approved forecast capex in the next regulatory control period is materially higher than it is likely to have been if a material amount of capex was not deferred in the current regulatory control period.

[27] For example, these issues are discussed in ESC, *Electricity Distribution Price Review 2006-10*, Final decision | Statement of purpose and reasons, October 2005

[28] AER, *Better Regulation Explanatory Statement Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013, p 30.

Where made, such an adjustment reduces the CESS payments for the following regulatory control period by the present value of the estimated marginal increase in forecast capital expenditure in the next regulatory control period attributable to capital expenditure deferred from the current regulatory control period.

3.4.3 Ex-post review of capital expenditure

In the context of the AEMC's 2012 Economic Regulation rule change, the NER were amended to allow the AER to review the amount of capital expenditure rolled into the RAB, to ensure its consistency with certain efficiency-based requirements. If these requirements are not satisfied, the AER may determine that the amount of capital expenditure to be rolled into the RAB should be less than the actual capital expenditure incurred by the TNSP.[30]

One of the requirements for disallowing an amount of expenditure to be rolled into the RAB is known as the overspending requirement. If the sum of capital expenditure incurred by the TNSP exceeds the sum of forecast capital expenditure that has been accepted or substituted by the AER, then the AER may exclude some or all over the overspend if it concludes that this amount is not prudent and efficient. In making this determination, the AER must only take into account information and analysis the TNSP could reasonably be expected to have considered at the time it undertook the expenditure.

[29] AER, *Better Regulation Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013, p 9.

[30] NER, S6A.2.2A.

4. Administrative means for optimising delivery of large project

Regulators often introduce administrative means to provide (or increase) incentives for service providers to strive for efficiency in the level of investment and the practical delivery of those investments in the long term interests of consumers. The nature of the incentives required in the context of large, discrete transmission investments are inherently linked to the intrinsically higher degree of uncertainty as to the expected benefits and costs of these projects.

Uncertainty around the benefits and costs of large, discrete investments necessarily extends to uncertainty regarding cost recovery for TNSPs. TNSPs are likely to be risk averse – reflecting the investors attracted by their relatively low risk and stable cash flows, and commensurate with assumptions that underpin the allowed rate of return.

The existing regulatory mechanisms in the NEM encourage TNSPs to over-forecast large project costs. However, the intrinsic uncertainty associated with large, discrete projects, combined with the prospect of penalties under the regulatory regime, also means that TNSPs are likely to face a degree of risk in relation to these projects that is greater than that for 'business as usual' investments. The combination of these effects can be expected to give rise to demands for a 'buffer' between a TNSP's forecast costs and a best estimate of project costs. The existence of this buffer is likely to result in consumers paying more than is necessary for large, discrete projects, or even in these projects not proceeding.

In the remainder of this section we describe in greater detail the challenges of addressing large, discrete transmission investments within the existing incentive-based mechanisms. Further, we propose five complementary administrative means by which the AER may be able to promote the long term interests of consumers by encouraging risk averse TNSPs to forecast and efficiently deliver large transmission investments despite their intrinsic uncertainty – which we summarise in figure 4.1 below.

Figure 4.1: Regulatory reform options to optimise delivery of large projects

Underpinning each of these administrative means is the need to promote the long term interests of consumers by encouraging TNSPs to make efficient investment decisions in relation to large, discrete transmission projects. In particular, these administrative means increase the predictability of the regulatory framework – a process that ultimately offers increased confidence:

- for consumers that large discrete transmission projects are being delivered efficiently and without excessive levels of cost buffering; and
- for TNSPs, so they have less incentive and ability to inflate cost forecast in their contingent project application.

We note that a consequence of increasing the predictability of the regulatory framework, particularly as it relates to the assessment of expenditure once made, is that the risk of cost overruns is shifted onto consumers (and potentially other parties such as government). This risk transfer can be regarded as the trade-off to induce risk averse investors to take on uncertain projects at a lower expected cost. Further, the nature of the proposed administrative means is such that they should provide the AER and consumers with greater confidence that the expenditure incurred by TNSPs is prudent and efficient.

4.1 Existing incentive mechanisms may not promote the NEO in relation to large investments

The regulatory framework that applies to transmission is designed to balance the potentially conflicting needs to:

- prevent TNSPs from misusing their market power by setting prices in excess of efficient costs; and
- retain strong incentives for TNSPs to perform efficiently, to reveal their efficient costs, and to pass on to customers the benefits of improved efficiency through lower prices.

The regulatory framework that applies to TNSPs in the NEM balances the tension between these two objectives through various incentives established by the NER. The principle underpinning this framework is the setting of quantitative targets (eg, capital expenditure allowances) over a regulatory control period. If the business is able to outperform its targets (eg, actual capital expenditure is lower than the allowance), while still meeting other targets (such as reliability), it is permitted to keep a proportion of the profits for a period of time, with the balance passed on to consumers through lower prices. In this way, the regulated business is encouraged to act efficiently so as to minimise its costs while meeting other targets.

Within this framework, administrative means to ensure that transmission projects are efficiently procured are underpinned by:

- the use of ex-ante controls, such as the five-year regulatory revenue determination, the contingent project application process and the CESS; and
- the ability to draw on ex-post review of capital expenditure.

In the remainder of this section we discuss how these existing incentive mechanisms may not, when applied to large transmission projects, promote the NEO. In particular, we explain that the current suite of ex-ante incentives incentivises TNSPs to:

- maximise forecast expenditure, since this is what determines the revenue allowance for the initial regulatory period; and
- minimise actual expenditure, so as to increase the incentive payment received.

It follows that TNSPs are presented with inherent incentives to seek out excessive incentive payments.

However, we also describe how the intrinsic uncertainty associated with large, discrete transmission projects generates a greater prospect of cost overruns. In combination with the CESS mechanism and the prospect of ex-post review, TNSPs could be expected to require a ‘buffer’ between the forecast costs that are the focus of these regulatory mechanisms and a best estimate of project costs.

4.1.1 Existing ex-ante mechanisms create an incentive to over-forecast costs

We describe in section 3.3 that TNSPs are responsible for all aspects of project delivery, ie, procurement in the NEM operates under a monopoly model.

By its nature, the monopoly model of procurement provides limited incentives for productive efficiency. TNSPs are monopolies who, in the absence of regulation, would find it profit maximising to set prices at levels above efficient costs and undertake less investment than would be socially optimal. In contrast, the objective of the regulator is to induce the monopolist to undertake beneficial investments whilst restraining its pricing to efficient costs.

However, the task of the regulator is complicated by significant information asymmetry – regulators cannot observe a TNSP’s efficient costs, but rather only those costs that are actually incurred. It follows that, absent incentives to balance the tension between the conflicting objectives of the monopolist and regulator, TNSPs may have poor incentives to build, own and operate the transmission networks efficiently.

The NEM’s incentive-based regulation framework is designed such that TNSPs and consumers share the risk of the transmission network being built, owned or operated inefficiently. In particular:

- the CESS operates such that any increase or decrease in capital expenditure relative to the forecast level is shared between TNSPs and consumers in an approximately 30/70 split; and
- the efficiency benefit sharing scheme (EBSS) operates such that any increase or decrease in operating expenditure relative to the forecast level is shared between TNSPs and consumers in an approximately 30/70 split.

Although these mechanisms are designed to share efficiency gains and losses between TNSPs and consumers, they also contribute to the incentives faced by TNSPs:

- to maximise forecast expenditure since this is what determines the revenue allowance in the current regulatory period; and
- to minimise actual expenditure, to increase the incentive payment that they receive (such as CESS payments).

We note above that there is no formal obligation on TNSPs to invest. Rather, following a successful RIT-T and contingent project application, a TNSP must decide whether to proceed with an investment. This decision typically follows the AER’s decision on the contingent project allowance, since it enables a TNSP to consider the revenue allowance and obtain access to the necessary financing for the project.

The revised contingent project triggers in the actionable ISP framework establish a link between the contingent project application and the AEMO feedback loop. In particular, the capital costs submitted as part of a contingent project application cannot exceed those examined in the feedback loop.

Since capital costs are a large proportion of the revenue stemming from a contingent project, this interrelationship creates an incentive for TNSPs to search for the highest capital costs that pass the feedback loop, to maximise the resulting revenue allowance. However, two features of the existing regulatory framework limit (but do not eliminate) this incentive, ie:

- the requirement to reapply the RIT-T if information changes such that the preferred option may no longer be preferred, which may be triggered by large increases in cost; and
- the risk of failing the feedback loop and the project no longer comprising part of the optimal development path, if the TNSP increases capital costs by too much.

4.1.2 TNSPs may demand greater cost buffers given the intrinsic uncertainty of large, discrete projects

We describe in section 1.2 above that large, discrete projects are subject to intrinsic uncertainty as to their costs and benefits. These uncertainties increase the prospect that there may be material cost overruns on a project.

Cost overruns give rise to two sources of potential financial penalties for TNSPs, namely:

- penalties under the CESS, to the extent that project specific cost overruns cause actual capital expenditure to exceed forecast capital expenditure; and
- the potential for exclusion of capital expenditure from the RAB if the AER conducts an ex-post review and finds some or all of this overspend to be inefficient.

It follows that TNSPs can be expected to respond to the increased prospect of material cost overruns by seeking a greater buffer between the cost forecasts submitted for approval and a best estimate of project costs.

Penalties under the CESS

The CESS rewards TNSPs for spending less than their forecast capital expenditure and penalises them for spending more. These penalties are symmetric, ie, an overrun of $1 million gives rise to a penalty that is the same magnitude as the reward for saving $1 million.

Notwithstanding the symmetry of the CESS mechanism, in the context of intrinsic risk associated with large, discrete transmission projects, the prospect of a material cost overrun is likely to be greater than would otherwise be the case.

Compounding the effect of the prospect of cost overruns is the fact that this risk for large, discrete projects cannot be diluted across a TNSP's broader expenditure profile. The structure of the regulatory framework is such that TNSPs manage the risk of cost overruns by compensating for overspends on some projects by underspending on others – ultimately incurring actual capital expenditure under the ex-ante allowance. However, the size of the expenditure associated with large, discrete projects means that it is unlikely a TNSP will be able to absorb a material cost overrun in other parts of its investment portfolio.

It follows that, under the existing regulatory arrangements, TNSPs are likely to seek to secure a greater buffer between the cost forecast and their best estimate of costs for large, discrete projects – and that this is likely to be a rational response to the apprehension of material cost overruns and CESS penalties.

Prospect for ex-post review

We describe in section 3.4.3 that, under the NER, the AER has the power to undertake an ex-post review of a TNSP's capital expenditure where it overspends on its ex-ante allowance. Through an ex-post review the AER has the right to exclude capital expenditure from the RAB where it considers part or all of the overspend to be inefficient.

The threat of ex-post review opens the potential for the exclusion of capital expenditure from the RAB, such that a TNSP would not be able to recover the full cost of an investment. It follows that how this threat is wielded is important to the incentives of TNSPs to make efficient investments. At its most extreme, if a TNSP believes that, despite best efforts to be prudent and efficient, there remains a material prospect that part of its expenditure is unlikely to enter the RAB, then it is unlikely to be willing to undertake investment.

We understand that there is concern amongst TNSPs regarding the threat of an ex-post review triggered by an overspend on large, discrete transmission investments. This increase in the perceived likelihood of an ex-post review is a result of the prospect of cost overruns on actionable ISP projects, since:

- the existing ex-ante arrangements require a detailed forecast of costs against the backdrop of the high degree of intrinsic uncertainty of these investments; and
- there is uncertainty as to how and whether costs associated with early works can be recovered despite the requirement on TNSPs to complete them.

The perceived threat of an ex-post review for TNSPs due to the prospect of cost overruns may be exacerbated by uncertainty as to how an ex-post review would be applied. In particular, the AER has not to date invoked its ex-post review powers, meaning it is unclear how the review would be undertaken.

We note that the AER's capital expenditure incentive guidelines do provide some guidance on the ex-post review process. The guidelines set out a two-stage process whereby the AER:[31]

- considers the TNSP's actual expenditure performance (ie, whether there is an overspend, whether the overspend is significant and whether there is a history of overspending); and
- if required, undertakes a detailed assessment of the drivers of the TNSP's capital expenditure and its management and planning tools and practices.

Central to this process is identifying the drivers of the capital expenditure overspend and determining whether these drivers were within the control of the TNSP. However, it is unclear what particular drivers for capital expenditure would be deemed to be in or out of the TNSP's control.

Further, although the guidelines provide an overview of the ex-post review process, there remains ambiguity regarding how it will be applied in practice. By way of example, the guidelines note that, with respect to management practices, the AER will assess whether the TNSP has applied:[32]

- appropriate project management plans and processes; and
- appropriate project governance and capital governance.

However, the guidelines do not appear to provide guidance on what the AER deems to be appropriate management and governance processes. There may be an information asymmetry as to whether the processes followed by TNSPs would be deemed appropriate, or whether current practices expose TNSPs to having capital expenditure excluded from the RAB.

It follows from the above that the existing guidelines regarding ex-post review are unlikely to be sufficient to mitigate the effect of the perceived threat of an ex-post review. This is a further factor that could drive TNSPs to seek a greater buffer between cost forecasts and their best estimates of costs for large, discrete projects.

4.1.3 Summary of our assessment

Figure 4.2 summarises our assessment of the existing administrative means for revealing efficient costs in the NEM. In our opinion, the existing incentive mechanisms:

- provide strong incentives for productivity efficiency since TNSPs are incentivised to minimise actual expenditure so as to maximise their incentive payments; and
- share between TNSPs and consumers the risk that transmission investments are implemented inefficiently.

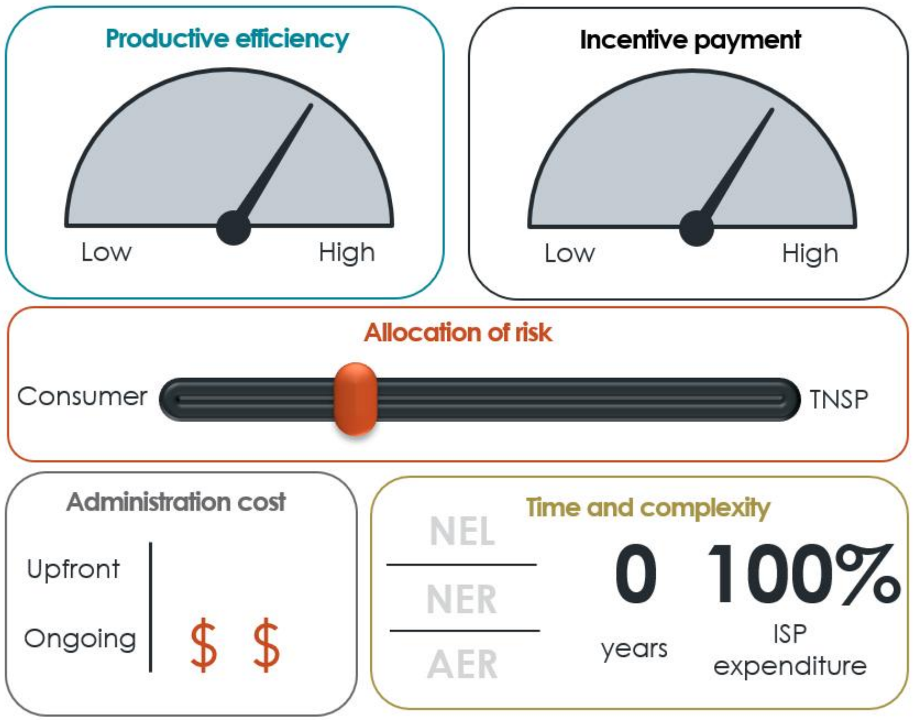
Further, by virtue of being the framework presently used, the existing incentive mechanisms:

[31] AER, *Better regulation | Capital expenditure incentive guideline for electricity network service providers,* November 2013, pp 14-15.

[32] AER, *Better regulation | Capital expenditure incentive guideline for electricity network service providers,* November 2013, p 15.

- involve no up-front costs (since these have already been incurred) and a medium level of ongoing costs – reflecting the resource intensive nature of the revenue determination and contingent project processes; and
- have the benefit of applying to all ISP expenditure, since they are currently in place.

Figure 4.2: Assessment scorecard for administrative means for revealing efficient costs in the NEM



4.2 Procurement guidelines

Procurement is a necessary component of the development of large projects, involving numerous decisions that can have considerable influence on project success. Its importance means that there are likely gains to be derived from promoting best practice procurement, eg, by encouraging competition where applicable or promoting the sharing of learnings so as to prevent mistakes being repeated.

One means by which the AER may promote best practice procurement is by developing and implementing procurement guidelines. Aside from allowing the AER to expose TNSPs to more discipline and accountability over their procurement activities, this may assuage the perceived threat of ex-post review highlighted in section 4.1.2, and promote a reduction in administrative costs associated with the AER undertaking ex-post reviews.

The implementation of procurement guidelines provides the AER with the opportunity to promote cost efficiency without necessitating continuous oversight. Rather, the AER's involvement would be limited to developing, implementing, and occasionally updating guidelines, with which TNSPs must comply. TNSPs would be permitted to deviate from guidelines but doing so without adequate justification would risk portions of any related expenditure being deemed inefficient in any subsequent ex-post review.

A natural extension of this option is to further increase the AER's involvement in the procurement process. The extent to which involvement is increased can vary, ranging from:

- the AER providing further structure around the means by which TNSPs procure, eg, by providing a centralised hub and tendering platform that TNSPs must use to tender works; to
- the AER taking control over procurement decisions, eg, by hiring a procurement expert or project manager as explored in section 5.5 or by taking responsibility over evaluating contracts and selecting the successful

bidder as occurs in tending of transmission to offshore wind developments in the UK.

It is important to note that any of these changes will increase the administrative costs incurred by the AER.

4.2.1 Procurement guidelines may encourage efficient costs and provide more certainty regarding ex-post reviews

As highlighted in appendix A1, procurement is a necessary component of the development of large projects, and involves numerous complex decisions that have considerable influence over project success, eg:

- What is to be procured?
- How are contracts to be designed?
- What mechanism is to be used to determine the successful bidder(s)?

Due to the abundance of options available, and the potential for inefficient decisions to be made, there are likely to be benefits from the characterisation of best practices, providing for:

- the form of contract to be used;
- the mandated use of competitive tender under suitable conditions; and
- the use of best practice methods of construction to deliver investments at least cost to consumers.

In this sense, the provision of guidance acts to drive efficient investment by limiting the potential for inefficient procurement decisions. While such inefficient decisions may occur due to aversion to utilising relatively new or innovated processes, they may also arise due to lack of awareness of innovative ideas. Consequently, guidelines promote cost efficiency in multiple ways.

For example, if the guidance outlines consideration of certain design processes such as the use of aerial stringing rather than pole/manual stringing, then:

- the TNSP is made aware of the need to consider the use of aerial stringing; and
- the TNSP knows that, if it does not consider aerial string and relies upon pole/manual stringing at higher cost, it may not recover any increase in costs to which this decision gives rise.

We consider that guidance does not function solely to restrict the procurement decisions of TNSPs, rather it provides a means by which TNSPs can mitigate risks associated with ex-post reviews, and so may assuage the perceived threat of ex-post reviews highlighted in section 4.1.2. We envisage that the introduction of guidelines would inform the conduct of ex-post reviews, ie:

- if the guidelines have been followed, an expenditure reduction would be less likely to be imposed; and
- if the guidelines have not been followed, and the TNSP cannot justify its deviation from the guidelines, then this may provide circumstances in which the exclusion of inefficiently incurred costs could be contemplated.

The introduction of a more formulaic system which identifies deviations from best practice would also enhance the efficiency of the AER's conduct of ex-post reviews, and reduce other administrative costs involved in decision making. For example, ex-post reviews could adopt a check list structure, ie, the AER would evaluate whether the TNSP has followed the best practice guidance, and in the cases that deviation has occurred, assess the impact of such deviations.

Due to the risk averse nature of TNSPs and the perceived risks associated with ex-post reviews, we consider that there would likely be strong compliance with any AER procurement guidance. This places significant importance on procurement guidelines being well designed and leads to a trade-off in determining the degree of flexibility allowed to TNSPs under the guidelines, as between:

- the desirable prevention of poor procurement practices that impose greater costs or unnecessary risks on consumers; and
- the undesirable restriction of innovative procurement practices that offer the prospect of reduced costs for consumers.

We discuss some considerations and difficulties pertaining to procurement design in appendix A1. For guidelines to be of maximum benefit, sufficient thought should be put into mechanism design (ie, how auctions to be run) and contract development (ie, which incentives are present, and which incentives should be promoted).

A similar concern relates to the frequency of update of guidelines. There is a foreseeable risk that TNSPs may independently undertake these projects, without adequately sharing learnings. To remedy this, we consider that guidelines must attempt to encourage the development of learnings across projects, and so mitigate the likelihood of the repetition of costly errors. These efforts act to mitigate the difficulties associated with the discrete and one-shot nature of these investments.

At a minimum, efforts should be made to promote the sharing of innovations and findings from previous projects.[33] This may involve the AER hosting post-project review sessions which describe issues that occurred and how they were resolved. If these learnings are well documented pre-development, and are ignored by the developer, this may provide circumstances in which the exclusion of inefficiently incurred costs as a result of these learnings not being implemented could be contemplated.

The above highlights a possible extension to the provision of procurement guidance. Indeed, we consider that there are numerous extensions that increase the involvement the AER, while enhancing procurement efficiency. Once such example is the development and provision of a centralised tendering platform, which promotes the sharing of requests for construction works. The platform may begin as a means for enabling TNSPs to reach an increased contractor audience but may extend to allow the AER to increase its involvement in the selection process.

We note that procurement guidelines would also need to be adapted to reflect other adjustments in the regime. For example, if incentives to abandon or delay projects is introduced, the guidelines would need to evolve to clearly stipulate that if abandonment or delay is optimal, then it should be undertaken. This is similarly true for the majority of options we have considered, eg, staging and information disclosure.

4.2.2 Risk would be mitigated but transferred towards consumers

One of the core purposes of the provision of guidelines is to encourage TNSPs to follow best practice procurement. Consequentially, the guidelines should act to promote a reduction in the total risk to which consumers and TNSPs are exposed.

While total risk may be reduced, the distribution of risk faced by parties in the event of cost overrun is altered. Guidelines may alter the allocation of the risk of cost overruns towards consumers. This is because there is an increased prospect that a cost overrun might be determined as efficient in a subsequent ex post review if the TNSP has complied with the guidelines.

However, it is also possible that consumers may be allocated fewer risks, to the extent that a well-designed procurement process may utilise contracts with fixed-price components to transfer some of this risk onto a contractor. In this case, risk would be distributed between the contractor and the consumer,

[33] For example, the developers of Marinus Link might usefully be able to learn from the experience of others in constructing and operating Basslink.

reflecting that there are numerous ways in which the effective price of a fixed price contract may change.

4.2.3 The AER would develop guidelines and use them to inform ex-post reviews

The provision of procurement guidelines could represent a complementary addition to the current regulatory regime. Effectively, whilst not requiring significant adjustments to the regime, it would alter the role and significance of ex-post reviews, which would become an opportunity to review TNSP deviations from guidance and assess whether these actions were prudent and efficient.

The development of guidelines would result in the AER incurring upfront costs. As foreshadowed above, we consider that procurement guidelines would require the devotion of considerable thought, and so may require the dedication of sufficient time and resources to ensure that they are robust and strike an appropriate balance between discouraging inefficient practices whilst also promoting innovative approaches. This may involve the further review of international best practice procurement or the involvement of auction design and contract design experts.

We consider that the ongoing costs of administering guidelines are likely to be relatively low. Indeed, once the guidelines are created, they can apply into the future without necessarily requiring review. However, to ensure best practices remain up to date, the AER should adjust guidelines to reflect new information that comes to light over time, such as when concerns arise following (or during) the development of large projects.

Further, it seems likely that reductions in ongoing administrative costs could follow from the introduction of guidance. The issuance of guidelines would promote a reduction in the potential costs faced by the AER in the event that it conducts ex-post reviews. For instance, a move to a checklist approach of ex-post review would promote swift decision-making regarding efficiency of TNSP procurement. This efficiency gain may also reflect increased uniformity in procurement decisions made by TNSPs.

4.2.4 Summary of our assessment

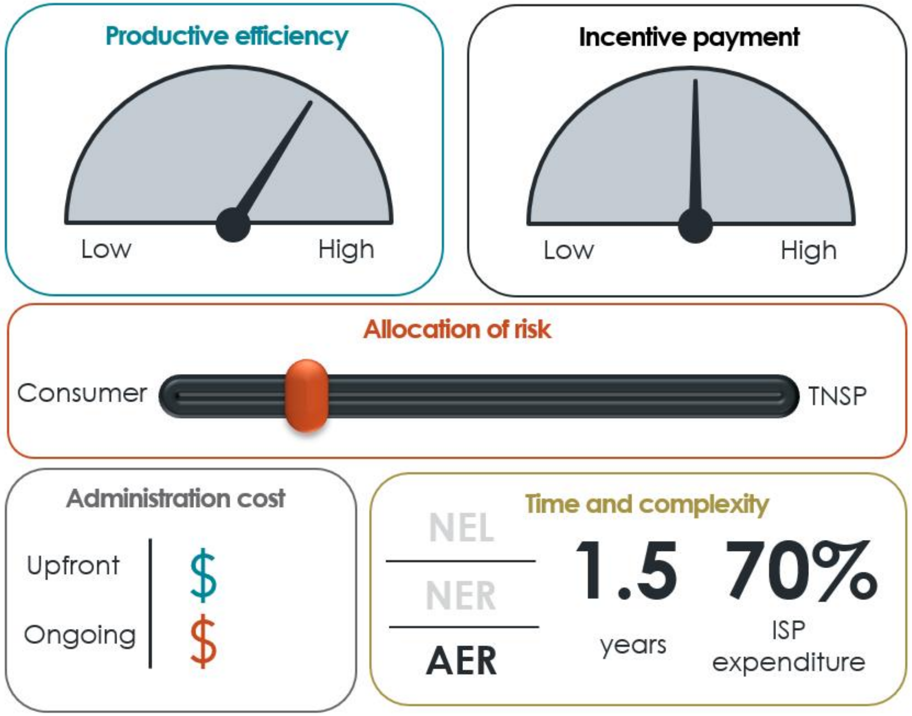
Figure 4.3 summarises our assessment of guidance for efficient procurement by reference to our analytical framework. In our view, this option:

- provides strong incentives for productive efficiency, since it works in a complementary manner with other incentive mechanisms currently used by the AER to encourage TNSPs to expend efficiently and mitigates the threat of ex-post review;
- lowers the costs faced by consumers since TNSPs will seek a lower incentive payment as a result of the greater predictability of the regulatory framework;
- reduces the overall risk the costs will overrun, and so the total risk exposure of TNSPs and consumers, but places a greater share of underutilisation risk on consumers;
- is associated with:
  - a low level of upfront costs since the AER would need to carefully develop procurement guidelines and potentially interact with procurement and auction specialists; and
  - a low level of ongoing costs reflecting that ex-post reviews are likely to become increasingly efficient, and the potential need to update guidelines to reflect project learnings; and
- may take up to 18 months to implement due to the need for AER change alone, meaning 70 per cent of ISP expenditure would be captured under this approach.[34]

[34] Based on the specified timing, the discussion set out in section 2.4

, and the assumption that forecast contingent project application dates reflect the final date in which projects can be influenced by options, we consider that the option would fail to capture the following projects: 'QNI minor', 'SA system strength remediation', 'VNI Minor' and 'Project EnergyConnect'.

Figure 4.3: Assessment scorecard for procurement guidelines



4.3 Increased use of project staging

In this section, we describe an option that provides additional means by which project staging might be undertaken, including at the requirement of the AER.

Staging involves breaking a large project down into smaller projects that can be completed sequentially. Staging is already a feature of large, discrete transmission projects, because:

- TNSPs can propose to implement projects in stages; and
- the ISP also considers the ability to progress projects in discrete stages and a staged development of projects may feature as part of the optimal development path.

These approaches to staging present solutions to specific problems. TNSPs may propose to stage projects where it is in their interests to do so, for example this may be a rational response to the potential threat of ex post review. AEMO's ISP may also progress projects in stages where this contributes to its objective function of meeting expected demand in the NEM at least cost.

In this section, we explain that staging has other benefits that may not be realised under existing approaches and given potential restrictions. It may also be beneficial for the AER to require a project to be broken into stages, and for each stage to require a separate contingent project approval (and potentially pass a separate RIT-T). This approach could potentially provide scope for the AER to:

- approve early works as a separate stage of a project, providing greater certainty to TNSPs of cost recovery for these works; and
- provide option value that would facilitate the efficient abandonment or delay of a project stage, as we discuss further in section 4.5 below.

In the remainder of this section, we discuss the incentives that encourage TNSPs to stage projects, and the potential for benefits and risks that arise from this. We also discuss the prospects for project staging to give rise to further benefits

4.3.1 Staging is a response to the threat of ex-post review

We explain at section 3.4.3 above that TNSPs are faced with the prospect of an ex-post review of their capital expenditure under S6A.2.2A of the NER.

Faced with the threat of an ex-post review, which eliminates expenditure which is determined to be inefficient, TNSPs may seek to mitigate this risk by breaking the project into smaller stages. By decomposing a project into multiple stages, the TNSP effectively invites the regulator to ‘assess and approve’ its expenditure decisions more frequently.

Project staging results in a more regular inspection of TNSPs’ costs, which reduces the potential harm that a TNSP would be exposed to in the event of an unfavourable ex-post review, since with more regular interactions with the regulator:

- the absolute magnitude of cost overruns that might potentially be at risk through an ex-post review will be lower; and
- the information obtained from cost overruns may inform more realistic estimates of costs for remaining project stages, which will reduce the risk of further cost overruns and adverse ex-post reviews.

This approach to staging is commonly used in the United States to provide evidence that the regulator considers that incremental investments are efficient.

This approach has also become more commonplace in Australia. A number of projects that are considered or being progressed through the ISP are staged, including Marinus Link and Hume Link.

This approach to staging may often be in the interests of consumers as well as TNSPs.[35] Providing greater opportunities for TNSPs to discover the project costs tends to reduce the prospect that TNSPs will proceed with projects that have efficient costs in excess of the gross benefits that they deliver. However, the long-term interests of consumers may be further promoted by providing the means to use staging in a wider range of circumstances, whether at the option of the TNSP or of the regulator. We discuss the potential benefits of project staging below.

4.3.2 Sources of benefits arising from project staging

We understand that project staging already occurs in the NEM. However, as we set out above, staging generally occurs so as to:

- reduce the prospect of an adverse finding in ex-post review; and
- provide the least cost means of meeting consumer demand over time.

In prospect, these rationales are likely to give rise to benefits to consumers. However, there may be other benefits to consumers arising from project staging, which we discuss below.

Enablement of efficient abandonment or delay decisions

We explain at section 4.5 below that it may be efficient to abandon or delay a project in circumstances where changes to the project’s net benefits make the value to consumers of continuing with the project no longer worthwhile or subject to greater uncertainty.

Increased use of project staging facilitates the making of abandonment or delay decisions, since it inserts additional steps within the delivery of a project at which TNSPs and the regulator must decide whether to proceed. The option benefits associated with increased staging of large projects means that it is less likely that projects for which net benefits have become negative since approval will continue to be progressed, since the staging process provides additional points of review and decision-making.

[35] We acknowledge that there may also be costs to staging that involve the slower delivery of transmission infrastructure (that might otherwise have given rise to benefits) to consumers.

Allow increased certainty of recovery of early works

One of the concerns raised in respect of the efficient delivery of large, discrete transmission projects in the NEM is the lack of incentives of TNSPs to undertake early works, given some degree of uncertainty as to whether these costs might later become not recoverable.

One option to formalise the means by which early works can be included within the RAB is to separate out these works as a separate stage in a project. Since early works provide for the prospect that a substantive project with potential benefits could be realised, early works may have option value that would be expected to offset their costs.

Provision of additional information to the regulator

Increased staging provides the regulator with additional information with which to evaluate the efficiency of capital expenditure. In this respect, staging is an alternative means by which to enable greater disclosure of information about projects, which we discuss further at section 4.4 below.

The greater information disclosed through increased granularity of projects may allow for more rigorous analysis of costs. In the case of ex-post regulation, more granular projects allow more frequent ex-post reviews and so earlier realisation of possible cost overruns. However, acting against these potential benefits is the prospect of increased administration costs through the application of more frequent regulatory reviews of costs and benefits – both in ex-ante and ex-post interactions.

Promotion of competition

For competition to succeed, participants must be attracted into a market for the provision of transmission projects. This requires there to be minimum efficient scale to allow participants to gain a foothold in the sector, which can be achieved through either:

- few large contracts; or
- many moderate contracts.

We consider that staging should, on balance, promote competition, whether in the context of competition to build transmission projects for TNSPs (as currently is often the case) or in the context of the introduction of additional competitive tension as we discuss in section 5 below. Staging provides more accessible foothold/trial investments, whilst not diminishing the total investment opportunity available. This tends to promote the prospect of new entry.

However, there may be a limit to the degree of staging that would promote competitive entry. Some project stages might be too small to interest competitors of scale. In this respect, we note that Ofgem’s competition criteria include that expected capital expenditure exceeds £100 million. [36]

4.3.3 Potential limits of project staging

The potential for benefits to consumers arising from project staging may be limited to the extent that:

- there is a lack of clarity about the use of certain forms of project staging that may provide benefits to consumers; and
- there is not currently scope for the AER to insist upon project staging where it considers that this will be in the long term interests of consumers.

[36] Ofgem, *Guidance on the criteria for competition*, 12 February 2019.

Limited clarity on the scope of project staging

Putting substance to the first of these concerns, it is helpful to distinguish two types of project staging, being:

- staging in which each stage, on its own, provides net benefits to consumers; and
- staging in which earlier stages only provide net benefits to consumers contingent upon later stages being completed.

Whereas the first type of staging splits a larger project into smaller projects, each of which delivers net benefits on a standalone basis, the second type of staging gives rise to smaller projects that deliver net benefits based only on the undertaking of further investments. For example, a project stage could deliver no benefits to consumers except for its option value. An example of such a project could be preparatory works to enable a further investment that would provide substantial benefits to consumers.

To the extent that TNSPs perceive that there may be risks associated with incorporating preparatory works into their RAB, they may be disincentivised to undertake such expenditure.

We understand that the AER has been considering the issue of different types of project staging in developing its ISP guidelines. The greater the guidance and clarity that can be achieved around staging, the greater the likely use of staging, including to overcome the risks of undertaking early works.

Decision making on project staging

Currently, most decisions as to how to break projects into stages are driven by TNSPs and their objectives. The examples set out above establish a number of other reasons why staging might be beneficial to consumers. However, TNSPs are unlikely to promote staging unilaterally as a means to secure these benefits.

This suggests that there may be a role for the AER to provide direction in relation to whether projects should be broken into stages, or broken into additional stages. The AER's considerations would be informed by the potential for further staging to:

- facilitate efficient abandonment and delay decisions;
- allow increased certainty over the recover of early works where this provides benefits to consumers;
- provide additional information with which to assess project benefits and costs; and
- promote competition for the procurement of transmission investments.

4.3.4 Summary of our assessment

Figure 4.4 summarises our assessment of staging by reference to our analytical framework. In our view, this option:

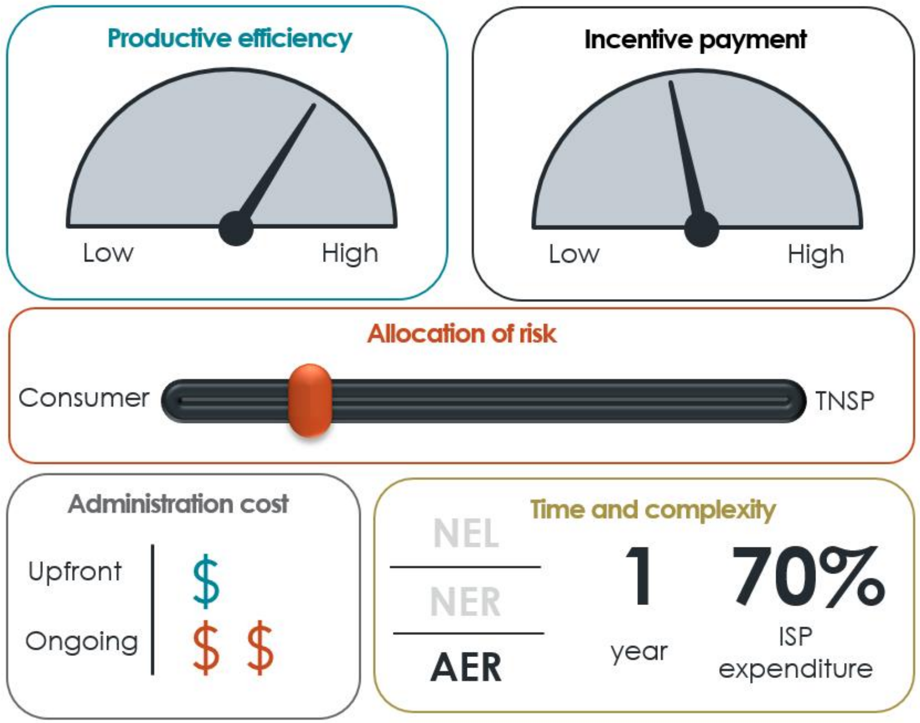
- provides enhanced incentives for productive efficiency, since it works in a complementary manner with other incentive mechanisms currently used by the AER to further encourage TNSPs to pursue efficient investments that they may otherwise fail to undertake, and reduces the likelihood that projects will continue where this is suboptimal;
- reduces the costs faced by consumers since TNSPs will seek a lower incentive payment, on account of the intrinsic uncertainty of these projects being spread and broken down across smaller steps; and
- may result in an overall reduction in risk to the extent that it draws on option value to avoid proceeding with projects that may ultimately not be optimal, and also shifts some risks from TNSPs towards consumers, since by staging TNSPs will be able to mitigate the prospect that their expenditure will be identified as sub-optimal in an ex-post review.

Providing for greater use of staging in the delivery of large, discrete transmission investments is associated with:

- a low level of upfront costs since it may require for the AER to provide further guidance setting out the process to enable project staging; and
- a medium level of ongoing costs reflecting the additional requirements that project staging will impose on TNSPs and the AER to engage in RIT-T and contingent project approval processes.

We estimate that this option may take 12 months to implement due to the need for the AER to develop and consult on its guidance, meaning that 70 per cent of ISP expenditure would be captured under the approach.[37]

Figure 4.4: Assessment scorecard for staging



4.4 Information disclosure

In this section, we describe an option, termed information disclosure, which complements the increased use of project staging (which we discuss at section 4.3 above) and the offering of incentives for abandonment and delay

[37] Based on the specified timing, the discussion set out in section 2.4, and the assumption that forecast contingent project application dates reflect the final date in which projects can be influenced by options, we consider that the option would fail to capture the following projects: 'SA system strength remediation', 'Western Victoria transmission augmentation', 'QNI Minor', 'VNI Minor' and 'Project EnergyConnect'.

(which we discuss at section 4.5 below). The option contemplates increased regulator involvement throughout the period spanning regulatory approval and asset commissioning. Specifically, it involves the provision of up to date information to the regulator, potentially on a quarterly basis, with the purpose of:

- keeping the regulator aware of changes to the factors that drive the benefits and costs of a project as they arise; and thus
- providing the regulator with an improved ability to make decisions as to:
  - the abandonment or delay of a project or project stage; or
  - the application of an ex-post review of project costs.

The more regular provision of information from the TNSP to the regulator is likely to increase the onus on the regulator to make timely decisions with respect to ex-post review and potential project abandonment or delay. That is, by receiving and reviewing the information, without ordering the abandonment or delay of the project, (as introduced in section 4.5 below) the regulator may effectively be seen as approving incremental project progress.

Relative to the status quo, this approach would be likely to:

- reduce costs for consumers by reducing the concentration of risks for a TNSP arising from the procurement of large, discrete transmission projects, commensurately reducing the prospect that these projects may not proceed due to the threat of ex-post review and therefore decreasing the cost buffer sought by TNSPs; but
- result in increased administration costs related to the preparation of the information disclosures and the additional expertise and staff time that would be required at the AER to review and analyse the information.

Since the option provides for increased regulatory involvement in decision-making that is currently the domain of the TNSP, it involves some transfer in risks from TNSPs to consumers. We also note that the option does not draw directly on regulatory approaches from other jurisdictions, and so there may be some risks associated with its adoption.

4.4.1 A regulatory option for encouraging efficient investment

As described in section 4.1 above, the existing regulatory frameworks may face challenges in addressing the procurement of large, discrete transmission projects because:

- the lag between project approval and development can lead to projects becoming inefficient yet TNSPs face incentives to complete these projects; and
- the threat of ex-post review may present an increasing risk for TNSPs contemplating investments in such projects.

It is reasonable to expect that, in workably competitive markets, firms undertaking large investments maintain close control over those projects, and monitor throughout any changes to the benefits or costs of proceeding with the project. The objective of regular information disclosure is to replicate this degree of control on behalf of consumers, ensuring that when it is no longer beneficial to proceed with a project then:

- the project is delayed or abandoned, which we discuss in section 4.5 below; or
- the TNSPs decision to proceed with the project becomes subject to potential ex-post review, which we discuss in section 4.6 below.

The information disclosure option involves the regulator being provided with project expenditure on a quarterly basis. We also expect that the regulator would stay apprised of potential project benefits, either through information disclosure or its own research and analysis.

4.4.2 Disclosure requirements encourage efficient expenditure through enhancing the ex-post review

Information disclosure provides enhanced opportunities for the regulator to confirm the efficiency of TNSP expenditure. This allows the regulator to overcome some information asymmetry problems, and so implement a more effective ex-post review process.

However, if information disclosure is occurring in combination with a single ex-post review at the end of the project, then it serves only to increase TNSPs' perceived likelihood that expenditure may later be determined to be inefficient and not included in the RAB. Together with the additional administration costs that TNSPs will face to disclose information to the regulator, this approach is unlikely to deliver benefits for consumers since they will face higher costs as a result of an increase in the cost buffer sought by TNSPs.

The case for information disclosure to deliver benefits and overcome the potential risks associated with delivery of large, discrete transmission projects could be improved. For example, the option could extend to involve regular decision-making by the regulator as to the efficiency of expenditure and the prospect of project delay or abandonment. These decisions could be published in regular statements alongside information disclosures.

This approach could potentially deliver benefits to both consumers and TNSPs, through:

- ensuring that projects continue to advance only when it remains in the best interests of consumers for this to occur; and
- providing TNSPs increased clarity and predictability as to how their expenditures will be assessed and rewarded within the regulatory regime.

It logically follows that these regular findings would be leveraged in the ex-post review, with the effect that the regulator's decisions in regular review of expenditure would be highly influential on its ultimate conclusions.

We note further that, to the extent that the regulator increases its involvement in a project to this extent, it may also raise the prospect that:

- capital expenditure for that project could be accounted for separately from capital expenditure associated with the general bucket of projects approved in the regulatory determination process – even after the regulatory reset; and
- the CESS may not apply, or could potentially apply differently, to capital expenditure for that project.

Regular analysis of project costs, combined with commensurate focus on the potential for project benefits to be realised, also provides the regulator the opportunity to identify whether continuing to progress the project will provide net benefits to consumers.

In the event that the project becomes unlikely to deliver net benefits on an incremental basis – setting aside from this consideration sunk costs that have been incurred since the project was approved – the regulator would be well placed to advise the TNSP to cease work on the project. When combined with incentives for efficient delay and abandonment, discussed in section 4.5 below, this provides the TNSP the opportunity to cease work on a project before further inefficient expenditure can be incurred. Consequently, the option may reduce total expenditure on projects that become inefficient after they are approved.

4.4.3 Risk allocation depends on the regulator involvement

Requiring increased information disclosure alone, ie, without regulator interaction, will see enhanced ability for the regulator to successfully utilise ex-post reviews, and so may increase the risk that the TNSP is exposed to. Additionally, the implications of the extended option, whereby the regulator confirms efficiency throughout the project and notifies the TNSP of its findings, has varied influence based on the completion of the project, ie:

- if the project is complete, there is limited influence on total risk and risk allocation, although the distribution of risk throughout the project is adjusted; and
- if the project is incomplete, the consumer bears all efficient expenditure and the TNSP bears all inefficient expenditure.

A further implication of the extended option is that it may reduce the TNSPs ability to manage within project risks, ie, manage early overruns with later underruns.

4.4.4 Information disclosure would place increased administrative burden on the AER and TNSPs

Implementing increased information disclosure requirements will increase the administrative burden faced by the regulator and TNSPs throughout project development.

To enable increased information disclosure, the regulator must set up processes and data sharing requirements that specify what information is required from the TNSP and how information is to be provided. Further, throughout the project the TNSP will share information with the regulator, which in turn will require it to collect the data either continuously or on a quarterly basis.

The magnitude of costs incurred by the regulator depend on whether it provides quarterly analysis and expenditure approval. If the regulator does provide quarterly approval, it will incur the costs associated. However, the increase is cost may be partially offset by the reduction in administrative burden that may arise as part of the final ex-post review.

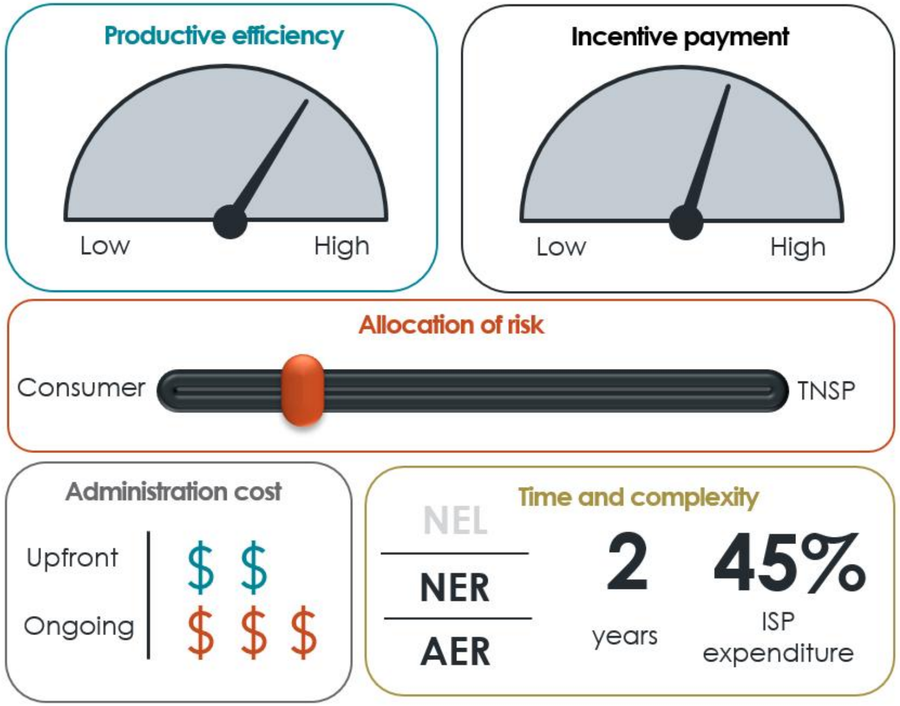
4.4.5 Summary of our assessment

Figure 4.5 summarises our assessment of introducing ‘information disclosure’ by reference to our analytical framework. In our view, this option:

- provides strong incentives for productive efficiency, since it works in a complementary manner with other incentive mechanisms currently used by the AER to further encourage TNSPs to pursue efficient investments and cease investments that are no longer efficient due to a change in circumstances;
- reduces the costs faced by consumers since TNSPs will seek a lower incentive payment as a result of the greater predictability of the regulatory framework (provided the disclosure is coupled with an efficiency review);
- if the information disclosure is purely for the purposes of informing the AER’s final ex-post review, the likelihood of an effective ex-post review which concluded TNSP expenditure is inefficient is increased;
- if the information disclosure is combined with the ability to analyse and provide efficiency review, the TNSP is insulated from completion risk since it enables full cost recovery of efficient expenditure on these projects;
- is associated with:
  - a medium level of upfront costs since the AER would need to initiate a rule change process and subsequently undertake further consultation to further refine the operation of the incentive; and
  - a large level of ongoing costs reflecting the requirements for TNSPs to send quarterly data to the AER, and potentially, for the AER to analyse it; and
  - may take up to two years to implement due to the need for a rule change process and further refinement of the incentive through consultation, meaning 45 per cent of ISP expenditure would be captured under the approach. [38]

[38] Based on the specified timing, the discussion set out in section 2.4, and the assumption that forecast contingent project application dates reflect the final date in which projects can be influenced by options, we consider that the option would fail to capture the following projects: ‘SA system strength remediation’, ‘Western Victoria transmission augmentation’, ‘QNI Minor’, ‘VNI Minor’, ‘Project EnergyConnect’ and ‘HumeLink’.

Figure 4.5: Assessment scorecard for information disclosure



4.5 Introduction of abandonment and delay incentives

Abandonment and delay incentives involve allowing a TNSP to recover all its prudently incurred costs where a project is abandoned or delayed due to factors outside of its control or where it becomes clear that the project is no longer economically justified. It follows that in the context of large, discrete transmission investments TNSPs may:

- not pursue efficient investments where the perceived risk of abandonment due to external circumstances is high and therefore the prospect of cost recovery is low; and
- continue to pursue committed investments in order to ensure recovery of costs, even when continuing with these investments may not be in the long term interest of consumers.

Put another way, the existing arrangements may encourage an inefficient level of investment due to the absence of a framework for remunerating abandoned or delayed projects. This concern is likely to be particularly material in respect of the large, discrete investments that are the focus on this report, since these projects may often be characterised by a high degree of uncertainty as to their benefits and costs.

Providing incentives for TNSPs to abandon or delay projects may promote efficient investment by providing greater predictability of the regulatory framework regarding cost recovery in relation to proceeding with large, discrete investments with inherently uncertain benefits and costs. Such incentives also provide the prospect that such investments can more easily be put on hold or abandoned when circumstances change. Both of these outcomes may be in the long term interests of consumers.

An abandonment and delay incentive could be complemented by increased information disclosure (which we discuss at section 4.4 above) and the issuing of procurement guidelines (which we discuss at section 4.2 above) to provide further confidence to the TNSP regarding the efficiency of its costs, while also enabling the AER to engage with the TNSP regarding whether the project should be abandoned.

4.5.1 Mechanisms for delay or abandonment may encourage an efficient level of investment

In our opinion, we consider there may be benefit in clarifying how the AER might assess expenditure on investments that are ultimately not completed. The prospect of this occurring is not entirely unforeseeable in the context of large, discrete projects with intrinsic uncertainty, even if it may not be contemplated at the current time.

To the extent that TNSPs perceive risks associated with the incorporation into their RABs of investments that are not completed, it follows that:

- where the prospect of abandonment due to external circumstances is material, a TNSP may elect not to pursue investment opportunities that are in the long term interest of consumers; and
- where the TNSP has committed to a project, it may continue to construct and commission the asset even when circumstances change such that its completion is no longer in the long term interest of consumers.

We discuss each of these investment inefficiencies in greater detail below, highlighting how the introduction of abandonment incentive can facilitate TNSPs pursuing investments that are in the best interests of consumers and ceasing those that are not.

Foregone investments due to risk of abandonment or delay

We describe in section 3.3 that under the current approach to planning and delivering large transmission investments TNSPs are responsible for all stages of project delivery. An important consequence of this responsibility is that TNSPs are ultimately exposed to risks that are not in their control yet may lead to the abandonment of or delay to a project. These risks include:

- rapid technological change or other changes in circumstances (such as demand shocks) resulting in a previously committed investment no longer being required; and
- difficulty securing the necessary environmental and planning approvals, noting many of the large investments represent the first greenfield developments of transmission infrastructure in a generation.

Since these risks are outside of the TNSP's control and may lead to projects being delayed or abandoned, TNSPs may elect to not pursue investments that are in the long term interest of consumers if they assess that there is a material prospect of abandonment. Put another way, asking TNSPs to bear risks that they are unable manage yet affect their ability to recover costs may lead to a lower than efficient level of investment, to the detriment of consumers.

Against this backdrop of significant risks faced by TNSPs in developing large, discrete transmission projects, introducing an incentive for TNSPs to delay or abandon projects in these circumstances could promote efficient investment. Providing greater clarity around how TNSPs recover prudent and efficient costs incurred up to the time of delay or abandonment removes this downside risk for TNSPs. With more certainty TNSPs would have a greater incentive to pursue efficient investments that are in the long term interest of consumers despite the risk of abandonment.

Pursuing committed investments no longer in the long term interests of consumers

There is a significant lag in time between a need being identified in the ISP, a solution being selected and refined through the RIT-T process, that project being approved through the contingent project process and then being constructed by the TNSP. The consequence of these time lags is that projects that were selected and/or approved on the basis of their benefits and costs may not remain optimal to pursue, either because:

- the underlying need that gave rise to the project changed; and/or
- the benefits that the project gives rise to have decreased; and/or
- the costs of the project have increased.

These changes may mean that the remaining benefits that can be achieved from pursuing a project are outweighed by the costs required for completion. In these circumstances, the prudent and efficient course of action is for the TNSP to cease the development of the project prior to its completion, since it will no longer deliver positive returns.

We consider that the current regulatory arrangements could be clarified regarding how TNSPs can recover the expenditure already incurred in instances where ultimately the asset is not completed. In light of this possibly uncertainty, TNSPs may have an incentive to continue to construct and commission the asset such that it can enter the RAB and be compensated for under the regulated revenue. This incentive is exacerbated by the fact that the AER would already have approved a revenue allowance for the project.

Providing further clarity for TNSPs to recover all prudent and efficient costs incurred up to the time of abandonment or delay would counter the incentive to pursue suboptimal projects to completion. However, to work effectively the mechanism would likely require greater information disclosure to facilitate the AER engaging with the TNSP on whether a project should be abandoned. These disclosure requirements are necessary because the revenues received by a TNSP at the time of abandonment will necessarily be lower than the revenue allowance – creating a further incentive to TNSPs to continue to complete inefficient investments. We discuss an option for greater information disclosure at section 4.4 above.

4.5.2 Risk allocation may depend on the cause of abandonment or delay

We note in section 2.3 that the AER's fundamental principle in relation to the allocation of risk is that risks should be allocated to those parties best placed to manage them. Within the existing regulatory framework, TNSPs ultimately bear the risk that they may not recover costs in the events that projects are delayed or abandoned, despite having no control over many of the factors that lead to project abandonment. Introducing incentives to delay or abandon a project would have the effect of insulating TNSPs from these risks.

Since this mechanism would shield TNSPs from the risk that it could not recover the cost of abandoned or delayed projects, it follows that this risk must be transferred to another party. The party that is best placed to manage this risk may vary depending on the cause of delay or abandonment. It follows that, to promote the efficient allocation of risk, the regulatory framework may need to be flexible in order to facilitate cost recovery from different parties depending on the cause of the abandonment.

By way of example there may be principled grounds for governments that are ultimately responsible for granting planning and environmental approvals to accept the risk of cost recovery in the event that these processes result in a project being delayed or abandoned. However, when projects are abandoned due to changes in technology or general economic circumstances, consumers may need to provide this function.

4.5.3 The AER would develop and administer mechanisms for delay or abandonment

Mechanisms to facilitate the delay or abandonment of transmission projects provide a means by which the AER can encourage TNSPs to incur only efficient expenditure when developing large, discrete transmission projects . It follows that introducing this mechanism would require processes similar to those used to establish the CESS and EBSS, ie:

- a rule change that provides the AER the ability to implement the abandonment incentive; and
- the development and subsequent implementation of the delay and abandonment mechanism by the AER.

Although the AER would be responsible for administering the mechanism it would likely to do so in a reactive capacity. By way of example, in the United States the onus is on the transmission developer to show that a prospective investment is subject to external circumstances that increase the risk of delay or abandonment. In cases where an investment is ultimately abandoned, it is also incumbent upon the investing developer to demonstrate to the regulator that the expenditure incurred to date is efficient.

While in this sense the role of the regulator is reactive, it likely follows the proactive development of guidelines to detail the requirements that TNSPs must satisfy to qualify for the abandonment incentive and ultimately recover its incurred costs. We discuss the role of procurement guidelines in section 4.2 above.

The delay and abandonment mechanism could also be complemented by requirements for greater information disclosure, which we discuss in section 4.4 above. Regular reporting from the TNSP to the AER would allow both parties to monitor the progression of an investment and engage on whether delay or abandonment is a prudent course of action. Further, developing procurement guidelines would provide a clear means by which the TNSP could illustrate that its incurred expenditure is efficient.

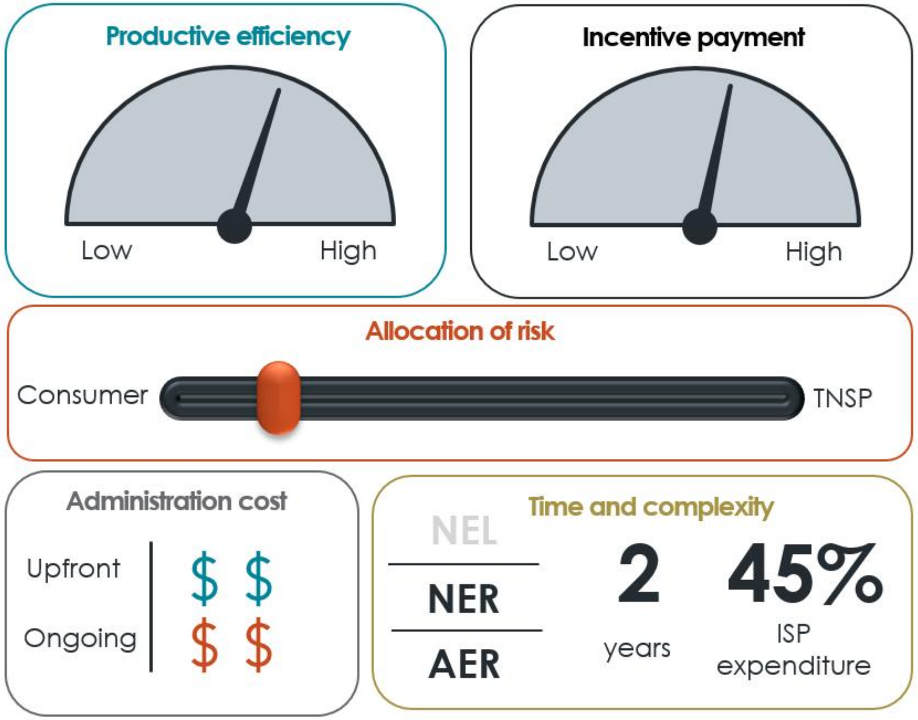
4.5.4 Summary of our assessment

Figure 4.6 summarises our assessment of the introduction of an abandonment incentive by reference to our analytical framework. In our opinion, this option:

- provides strong incentives for productive efficiency, since it works in a complementary manner with other incentive mechanisms currently used by the AER to further encourage TNSPs to pursue efficient investments and cease investments that are no longer efficient due to a change in circumstances (noting the decline in efficiency due to consumers paying for ultimately unused infrastructure);
- reduce the costs faced by consumers since TNSPs will seek a lower incentive payment as a result of the greater predictability of the regulatory framework;
- insulates the TNSP from abandonment risk since it clarifies cost recovery of efficient expenditure on abandoned projects, although the party to which this risk should be transferred is unclear (though most likely will be consumers);
- is associated with:
  - a medium level of upfront costs since the AER would need to initiate a rule change process and subsequently undertake further consultation to further refine the operation of the incentive; and
  - a medium level of ongoing costs reflecting the requirements for TNSPs to demonstrate that the nature of the project is suitable for application of the abandonment incentive and that the expenditure incurred up to abandonment is efficient; and
- may take up to two years to implement due to the need for a rule change process and further refinement of the incentive through consultation, meaning 45 per cent of ISP expenditure would be captured under the approach.[39]

[39] Based on the specified timing, the discussion set out in section 2.4, and the assumption that forecast contingent project application dates reflect the final date in which projects can be influenced by options, we consider that the option would fail to capture the following projects: 'SA system strength remediation', 'Western Victoria transmission augmentation', 'QNI Minor', 'VNI Minor', 'Project EnergyConnect' and 'HumeLink'.

Figure 4.6: Assessment scorecard for introducing an abandonment incentive



4.6 Implementing ex-post guidelines to reduce ex-post review uncertainty

We outline in section 4.1.2 above that the current form of guidance provided by the AER as to the ex-post review of expenditure is unlikely to be sufficiently specific to provide TNSPs with any degree of predictability as to how it would conduct such a review. Further, no ex-post review has yet been applied to a TNSP that would inform this. This lack of predictability, in combination with the risk averse nature of TNSPs, could contribute to large, discrete transmissions not proceeding where they would otherwise provide benefits to consumers.

In this section, we discuss how the AER could seek to better signal and define how it would apply an ex-post review of TNSP expenditure, so as to improve predictability.

However, clarification and specification of ex-post review guidelines will not unambiguously lead to greater investment. Rather, the effect will depend on the extent to which the guidelines:

- resolve uncertainty about how the AER would seek to apply its powers for ex-post review; and
- alter expectations about how the AER would seek to apply its powers for ex-post review.

Although there are potentially adverse effects if guidance were to negatively surprise TNSPs about the AER's willingness and approach to apply ex-post review, to the extent that an eventual ex-post review is very likely, there may be benefits that result from the alleviating uncertainty as to when and how it would undertake ex-post reviews.

4.6.1 The need for ex-post guidance

We explain in section 3.4.3 that the existing regime allows for an ex-post review in the instance that actual expenditure for a regulatory control period exceeds forecast or allowed expenditure (ie, as specified in the regulatory determination with relevant additions such as for contingent projects). The purpose of the ex-post review is to exclude capital expenditure that does not reflect the capital expenditure criteria from entering the RAB – ie, capital expenditure that does not reflect:[40]

> (1) the efficient costs of achieving the capital expenditure objectives;
>
> (2) the costs that a prudent operator would require to achieve the capital expenditure objectives; and
>
> (3) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

The NER state that the AER may only exclude capital expenditure above the approved allowance, and so there are limitations on the magnitude of reductions that the AER can make.

Although the AER has yet to exercise its powers of ex-post review, in our opinion it is likely to be required to do so at some point over the medium term, as it considers proposals to undertake the large, discrete investments arising from the ISP. We explain in section 4.1.2 above that these projects have benefits and costs that are inherently uncertain, and there is a prospect that one of more of them may incur capital expenditure substantially in excess of the approved allowance. This prospect is likely to trigger an ex-post review, given the disproportionate size of many of these projects relative to other investment plans that TNSPs are currently implementing.

Reflecting the potential for cost overruns on these large, discrete projects and the prospect of ex-post reviews, TNSPs may be concerned about the process that will follow if an ex-post review is triggered. In this respect, there is no past experience of ex-post reviews that would inform TNSPs as to the AER's willingness to utilise ex-post reviews, and the approach with which it would seek to undertake such a review.

[40] NER, 6A.6.7(c)

Although existing guidelines provide some clarification as to how the AER intends to undertake ex-post reviews, we explain in section 4.1.2 that these are unlikely to be sufficient to mitigate the effect of the perceived threat of an ex-post review. For example:

- the use of broad language in the existing expenditure forecast assessment guideline allows for wide discretion on the AER as to the factors and approaches that may be applied;
- the processes and procedures that would be implemented as part of an ex-post review are not set out; and
- the lack of certainty as to how the AER would account for cost overruns on contingent projects in ex-post reviews.

We highlight in section 4.1.2 that the consequences of a threat of an ex-post review can be considerable, eg, it may prevent investment in otherwise efficient projects, promote further incentives to inflate forecasts of capital expenditure,[41] or encourage inefficient substitution towards operating expenditure to reduce the likelihood of overruns. Indeed, a range of uncertainties can inhibit TNSP investment, including uncertainty as to the AER's ex-post assessment of efficient costs. If the TNSP believes that, despite best efforts to be prudent and efficient, there is still a material prospect that part of its expenditure is unlikely to enter the RAB, then it is unlikely to be willing to undertake investment. This is particularly likely to affect risk averse investors.

4.6.2 The implication of ex-post review guidelines

The development of improved ex-post review guidance would provide increased clarity to TNSPs as to how an ex-post review may be undertaken by the AER. Ideally, guidelines would provide predictability to the process that the AER would undertake to evaluate efficiency, eg:

[41] Although, this may not be material given there is already an incentive to maximise capex forecasts.

- the identification of specific inputs that will be deemed inefficient if overruns occur, eg, labour costs, or risks that can be hedged, reasonably mitigated or forecast;
- the identification of whether ex-post reviews will focus separately on contingent project overruns if other actual capital expenditure does not exceed the approved forecast; and
- the specification of appropriate processes and procedures for assessing whether capital expenditure is efficient and prudent.

Providing added clarity may address the issue of investors avoiding investments due to uncertainty regarding how the AER will approach ex-post reviews. However, we are cognisant of additional complexities. In particular, the AER providing additional guidance as to how it would seek to conduct ex-post reviews may have offsetting effects because it would:

- encourage additional investment to the extent that the guidance resolves uncertainties in how ex-post review would be applied; but
- discourage additional investment to the extent issuing the guidance causes TNSPs to increase their subjective assessments as to the prospect of ex-post review taking place.

Furthermore, there is the possibility that guidance is different to TNSPs' original expectations, or that there were conflicting effects on the perceived probability and significance of a given reduction. These concerns are highlighted in figure 4.7 below.

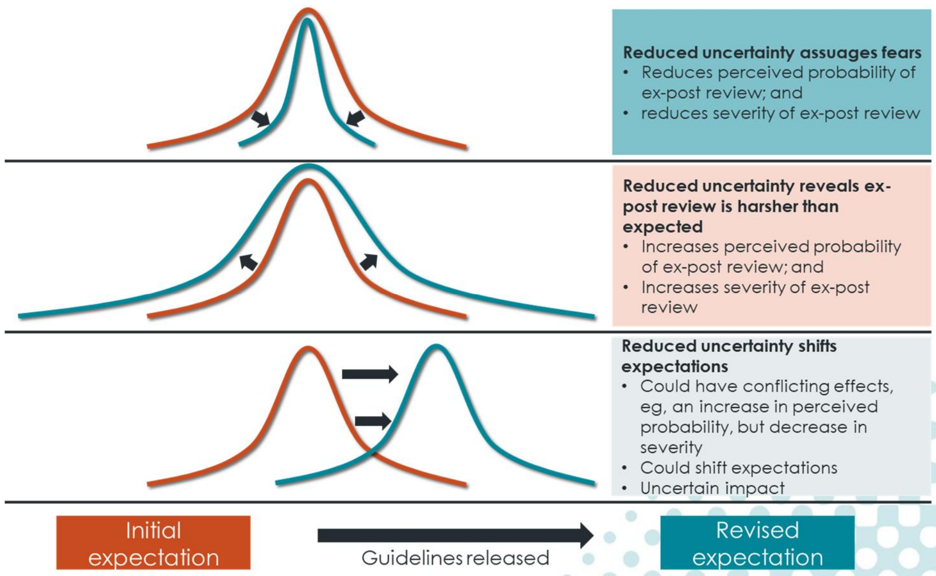
The consequence of an ex-post review occurring without explicit guidance in place would be the creation of implicit guidance. However, the AER would still retain flexibility in its future approach to conducting ex-post reviews. Furthermore, the implicit guidance may result in some TNSPs investing prior to discovering that the AER intends to apply the ex-post review in a more stringent fashion than they expected.

This leads to an auxiliary trade-off between:

- setting guidelines, at the risk of discouraging investment by revealing a more stringent ex-post review process than anticipated; or
- waiting until an ex-post review arises, whereby TNSPs may invest prior to the revelation of the ex-post review process.

Despite these complications, it may be prudent to contemplate that an ex-post review will arise in the future, and so will eventually necessitate guidance. Indeed, as the industry is relatively inexperienced with large, complex projects, the need for ex-post review may be greater in the near term. While there may be some instances whereby TNSPs are discouraged from investing due to the development of guidelines, we consider that it is worth being proactive and updating those presently available.

Figure 4.7: Possible impact of guideline



4.6.3 Implementing ex-post review guidelines

Our understanding is that the implementation of guidelines for ex-post review would not require any modification to the NER or NEL, and rather, would involve updating the guidelines already released to be more specific and clearer. Thus, we understand that the change might be expected to take approximately 18 months to implement.

Furthermore, we understand that ex-post review guidance would only be applicable to TNSPs with regulatory control periods that begin after the guidance is released. This reflects the nature of ex-post reviews, ie, that they are applied to all capital expenditure, rather than capital expenditure relating to a specific contingent project. This means that:

- guidelines will not take effect until the current regulatory control period ends, and so they may not capture projects that would otherwise be captured by a change that is implemented in 18 months; and
- if the guidelines are completed following the beginning of a new regulatory control period, they will not take effect until the next regulatory control period begins (which may take as long as five years).

Furthermore, we do not anticipate that issuing a guideline for ex-post review would substantially increase administrative costs. Although in the short run, the guidelines would require consultation and development, they would likely assist the efficient undertaking of future ex-post reviews and would not face substantial ongoing costs.

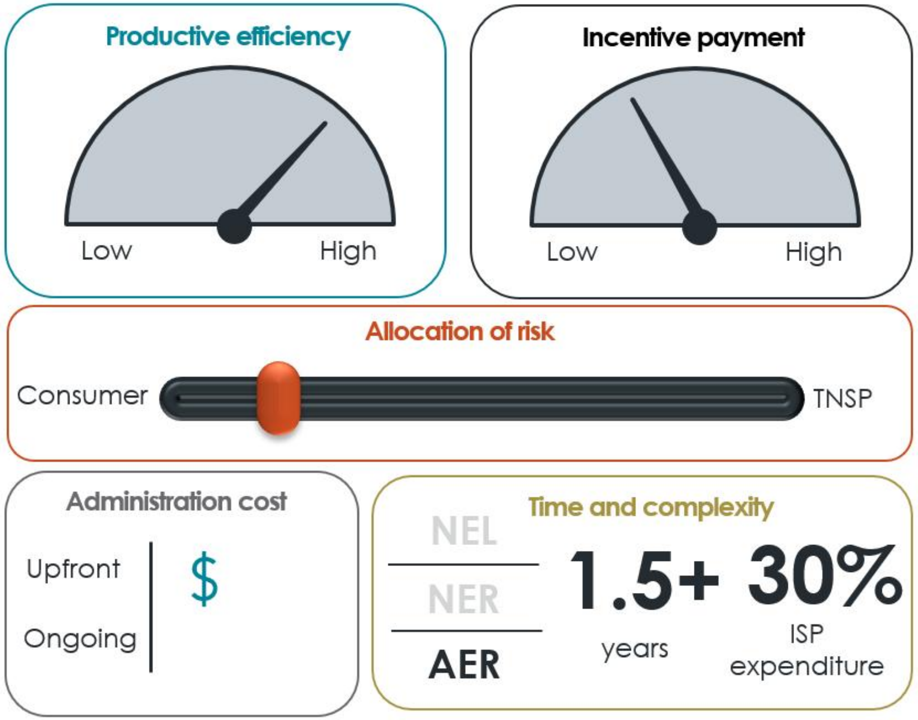
4.6.4 Summary of our assessment

Figure 4.8 summarises our assessment of the introduction of guidelines for ex-post review by reference to our analytical framework. In our view, this option:

- provides strong incentives for productive efficiency, since it could work to encourage TNSPs to pursue efficient investments;
- reduces the costs faced by consumers since TNSPs will seek a lower incentive payment as a result of the greater predictability of the regulatory framework;
- may reduce the risk of adverse ex-post reviews for TNSPs since they are likely to better understand the factors that would contribute to a negative finding;
- is associated with:
  - a low level of upfront costs since the AER would need to consult on and publish a guideline; and
  - a low level of ongoing costs reflecting the fact that the AER would likely need to incur costs to undertake ex-post reviews with or without the guideline; and
- may take up to 18 months to implement due to the need to prepare and refine a guideline, as well as additional time for new regulatory control periods to begin, and so 30 per cent of ISP expenditure would be captured under the approach.[42]

[42] Based on the specified timing, the discussion set out in section 2.4, and the assumption that forecast contingent project application dates reflect the final date in which projects can be influenced by options, we consider that the option would fail to capture the following projects: 'SA system strength remediation', 'Western Victoria transmission augmentation', 'QNI Minor', 'VNI Minor', 'Project EnergyConnect' and 'HumeLink'. In addition, 'VNI West' is unlikely to be captured due to the timing of relevant regulatory control periods.

Figure 4.8: Assessment scorecard for ex-post guidelines



5. Introducing competitive tension to the planning and delivery functions

In the previous section we described various administrative means by which the AER would be able to encourage incumbent, risk averse TNSPs to pursue large, discrete transmission investments despite their uncertainty and risk.

In this section we describe models of competition that would attract new transmission operators, including those with the potential for a greater risk tolerance, to deliver large transmission investments. In particular, we review potential options for introducing competitive tension to the planning and delivery of large transmission investments.

A principal benefit of introducing competitive tension is that it affords significant flexibility as to the components of planning and delivery that are exposed to competition. Accordingly, the focus of this section is on considering the potential range of functions that could be tendered. Under the existing arrangements in the NEM, TNSPs are not required to competitively tender any part of the delivery of large transmission projects. However, we understand that construction of such projects is often tendered, since:

- incumbent TNSPs do not typically have in-house construction capabilities; and
- tendering may assist a TNSP in demonstrating that it has been prudent and efficient in undertaking its capital expenditure.

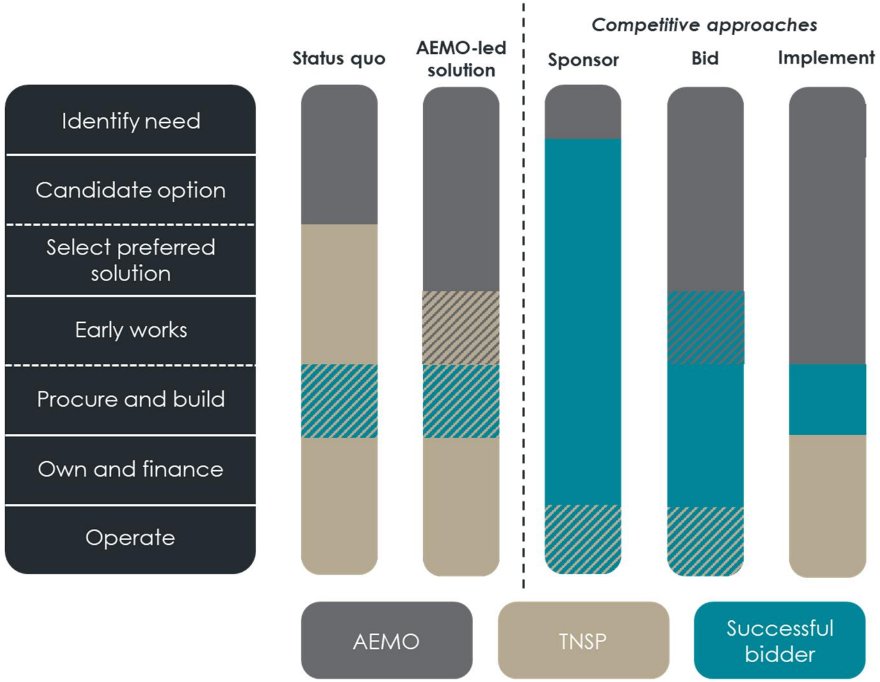
The potential scope for efficiency gains from additional innovation, and the presumptive risk aversion of existing actors within the planning and regulatory framework, forms an important part of these considerations. One of the key benefits to the introduction of competition is the additional rigour that this provides in seeking innovative solutions, a process that is difficult to incentivise by administrative means.

Each of the options that we assess in this section would involve significant and potentially complex changes to the existing processes in the NEM. For instance, some options may require changes to the scope of AEMO's planning role, either to extend this role to specifying the solution by applying the RIT-T, or by reducing the scope of the planning role through the use of a competitive process to identify the best solutions to a system need. These options are:

- sponsor-based competitive processes, where AEMO would select the best and most cost-effective solution to an identified need from competing tenders;
- bid-based competitive processes, where AEMO would select the best and most cost-effective means of implementing, owning and operating the solution that it itself has selected; and
- implementation-based competitive processes, where the AER would select the best and most cost-effective means of managing the implementation of the solution that AEMO has selected.

Figure 5.1 below depicts the varying scope of the roles and responsibilities under each of these options.

Figure 5.1: Models for introducing competition to transmission delivery



The appropriate arrangements by which large, discrete transmission investments are planned, selected, delivered and remunerated are inherently linked to the prevailing circumstances. It follows that any assessment of the different models of competition and regulation requires a considered examination of the circumstances in which they may operate effectively and whether these circumstances arise in the NEM context.

At a very high level, there are three factors related to cost and competition that determine the extent to which competitive procurement can be used as a means to assist in the delivery of large, discrete transmission investments. These are:

- the extent to which potential gains from innovation are available, which is also linked to the degree of information asymmetry between the TNSP and the service provider;
- the extent to which existing decision-makers (such as the TNSP and AEMO) are capable of innovation that would achieve efficient outcomes over the long run, or whether these bodies can be presumed to be risk averse and so prefer more conventional means of meeting power system needs; and
- the extent to which there is the prospect of a workable degree of competition that would allow functions requiring innovation to be sourced externally, which turns on:
  - the economies of scale and scope available to the incumbent;
  - the degree of investment separability from the incumbent's network;
  - the extent of cooperation required from the incumbent; and
  - whether there is a sufficient scale of investment to encourage wide participation.

In the remainder of this section, we review the existing planning and delivery arrangements in the NEM, with a particular focus on the extent to which the existing arrangements may not generate outcomes consistent with the long term interests of consumers because the prevailing incentives of the ultimate decision makers risk sub-optimal solution selection and delivery. Further, we provide a detailed overview of the competitive models described in figure 5.1 and assess each by reference to our analytical framework.

5.1 Existing planning and delivery arrangements

In this section, we explain the institutional and financial incentives faced by TNSPs that may distort the investment process in a manner that leads to the progression of sub-optimal solutions to identified needs. This risk is ultimately borne by electricity consumers through prices that reflect higher costs than may otherwise have been the case. Although the current regulatory regime provides incentives for efficient costs, the mechanisms in place focus on incentives for the cost efficient delivery of a given solution and so do not account for the risk of that solution being either sub-optimal at the time of its selection, or becoming so in the course of its delivery.

5.1.1 Incentives risk of inefficient solution selection and delivery

We describe in section 3.2 that the existing arrangements in the NEM are structured so that TNSPs are ultimately responsible for selecting and implementing the solutions to identified needs. This TNSP-led approach gives rise to the risks:

- solutions to identified needs may not be the most efficient or optimal; and
- the regulatory arrangements that govern the delivery of those solutions may not be the optimal means for minimizing their cost.

We discuss each of these risks in greater detail below.

Selection of sub-optimal solutions

TNSP-led solution selection and implementation gives rise to the risk that the preferred solution is not the most optimal, because of the intrinsic preference of TNSPs for network-focused as distinct from non-network options. There are two potential causes of this risk:

- TNSPs have an institutional preference for network solutions over non-network solutions, since their essential reason for being is to own and operate the transmission network; and
- the essential structure of the regulatory arrangements for the remuneration of transmission, and particularly its focus on profit-based compensation for additional capex but not opex, is likely to encourage TNSPs to give preference to capex over opex focused solutions – we refer to this as an intrinsic, capital expenditure preference.

We note that the strength of this capital expenditure preference turns on the regulatory rate of return exceeding the actual financing costs faced by the business. However, in exercising the difficult judgements that need to be made in relation to this regulatory parameter, the risk of setting the regulated rate of return too low, and thereby dissuading TNSPs from undertaking desirable investments, must also be weighed.

Irrespective of the stance implied by this ultimately unknowable balance between the risk of the regulatory rate of return being set too high or too low, the institutional role of TNSPs is likely to give rise to an intrinsic preference for network solutions. By consequence of their fundamental role as providers of transmission services, the knowledge and capabilities of TNSPs is orientated to supply-side, capital expenditure-focused solutions, rather than as providers of close substitutes for transmission-related infrastructure.

Although TNSPs are required to consider non-network options in the RIT-T (where these are identified in the RIT-T process or final ISP), their intrinsic preference is likely to cause them to take relatively optimistic views of the net market benefits of network options, thereby positioning a TNSP as integral to the preferred solution. In contrast, the technical capability of non-network (including demand-side) solutions to meet an identified need in a cost-effective manner is less likely to attract an optimistic assessment by TNSPs, thereby disadvantaging such solutions.

The ability of TNSPs to respond to this incentive has likely been strengthened by the removal of the AER’s review of the RIT-T under the actionable ISP framework. On the other hand, the requirement to use the inputs and assumptions of the ISP, as well as the prospect of dispute, does mitigate (but seems unlikely to eliminate) these incentives.

The consequence of intrinsic preferences for network-focused solutions gives rise to a material risk that the ultimately selected solution under the existing planning and regulatory arrangements may not be in the long term interests of consumers. Such risks would manifest where:

- a network solution may be identified when a non-network solution would have provided greater net benefits; or

- a network solution may satisfy the RIT-T whereas it may not have been economic to address the perceived need by any administrative means.

In either case, consumers ultimately bear these risks through higher prices. While the combination of ex-ante and ex-post incentives employed in the TNSP revenue determination process may effectively address the risk of inefficient levels of expenditure on delivering the selected solution, those incentives cannot address the risk of delivering a solution that was sub-optimal in terms of its selection process.

Inefficient delivery of the solution

We described in section 4.1.1 that the existing incentive mechanisms give rise to an incentive for TNSPs to over-forecast their capital costs. In particular, the interrelationship between the contingent project application and the AEMO feedback loop, coupled with the CESS, incentivise TNSPs:

- to maximise forecast expenditure, since this is what determines the revenue allowance for the initial regulatory period; and
- to minimise actual expenditure, so as to increase the incentive payment received.

5.1.2 Summary of our assessment

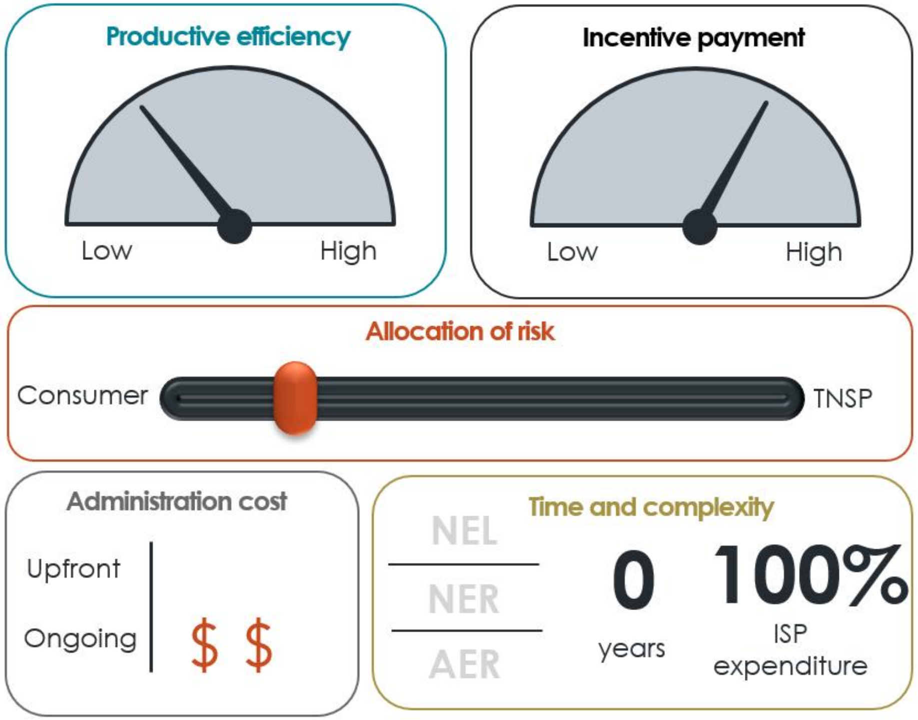
Figure 5.2 summarises our assessment of the existing approach to solution selection and implementation in the NEM by reference to the analytical framework we describe above. In our view, the current framework:

- provides mixed incentives for productive and so long term, dynamic efficiency, since:
  - > the institutional and financial incentives faced by TNSPs are such that network and non-network solutions cannot be presumed to be evaluated in a completely neutral manner; but
  - > where, once selected, the existing incentive mechanisms strongly encourage TNSPs to deliver projects at least cost; while
  - > these same incentive mechanisms are likely to encourage TNSPs to inflate and/or take a very cautious approach to forecast costs; and
- gives rise to two key risks that are predominantly borne by consumers:
  - > the risk that a network solution may be identified when a non-network solution may have provided greater net benefits – this risk is borne by consumers; and
  - > the risk that, once selected, solutions are implemented by means that are not in the long term interests of consumers – which is shared between TNSPs and consumers under the existing mechanisms.

On the other hand, in the context of our analytical framework maintaining the present framework:

- involves no up-front costs (since these have already been incurred) and a medium level of ongoing costs – reflecting the resource intensive nature of the ISP and RIT-T processes and the established procurement practices of TNSPs; and
- has the benefit of applying to all contemplated ISP expenditure, since it is currently in place.

Figure 5.2: Assessment scorecard for selecting and implementing preferred solutions in the NEM



5.2 AEMO-led solution selection

An AEMO-led approach to the selection of solutions to identified needs would retain many of the features of the existing framework in the NEM. However, the roles and responsibilities of stakeholders would alter. Under this option the responsibility of applying the RIT-T would be transferred from TNSPs to AEMO. Although TNSPs would no longer directly apply the RIT-T, they would likely need to play a supporting role to ensure that knowledge of the local network informs the assessment.

In the remainder of this section we explain that moving to a model where the system operator assesses and ultimately selects the preferred solution could be expected to reduce (although not necessarily eliminate) the risk of sub-optimal solution selection. In particular, an AEMO controlled decision-making process would no longer be affected by TNSPs' financial incentives, although a degree of preference for network solutions may remain.

Notwithstanding the potential for mitigation of the risks associated with the present, TNSP-conducted project selection process, consumers would continue to bear some risk of sub-optimal solutions being selected.

Finally, we highlight how moving to an AEMO-led model of solution selection is a pre-requisite for facilitating competition across a greater number of elements of project delivery, relative to the existing approach which provides for competition over the construction element alone.

5.2.1 AEMO conducted RIT-T may reduce risk and promote efficiency

We explain in section 5.1.1 that institutional and financial incentives may distort the project selection process in a manner that creates the risk of sub-optimal network-focused options being selected over non-network alternatives. One way in which this risk can be addressed in the context of large transmission projects is to transfer the ultimate responsibility of assessing candidate solutions (ie, undertaking the RIT-T), to AEMO.

By its role as an independent, not-for-profit system operator, AEMO's decision-making process is not subject to the financial incentives faced by TNSPs. AEMO does not possess a regulatory asset base on which it earns a return and, as such, has no financial motivation for preferring network solutions over non-network alternatives. Put another way, the absence of financial incentive suggests that AEMO should be agnostic between network and non-network solutions to identified needs. This indifference is likely to reduce the overall risk of a sub-optimal solution being selected and to advance the long term interests of consumers since AEMO would be less motivated:

- to inflate the net market benefits of network options; and/or
- to give insufficient focus to the feasibility of non-network options.

Despite AEMO itself having no financial incentive to prefer network options, such influences may continue to affect the decision-making process since TNSPs would need to participate in an advisory fashion. An important aspect of the rationale of the current network planning model is that TNSPs' detailed knowledge of their network makes them better placed to apply the RIT-T. AEMO as a national planner lacks this detailed knowledge and would need to rely on incumbent TNSPs to inform its assessment. It follows that integral to the success of this model is that AEMO possesses the necessary technical capability to critically evaluate information provided by incumbent transmission service providers.

Further, whilst AEMO may not be subject to inherent preferences arising from financial incentives, there remains some prospect of an institutional preference for network solutions. The primary objective of AEMO as the independent system operator is to ensure reliable and secure system operation. Innovative non-network solutions are more likely to be associated with inherent uncertainty as to whether they can adequately support these objectives. In contrast, traditional network solutions have the benefit of long-standing performance in supporting network reliability and security. It follows that AEMO's familiarity with, and confidence in, network solutions can be expected to give rise to some institutional preference for network solutions.

5.2.2 AEMO conducted RIT-T pre-requisite for introducing competition

Transferring the responsibility of undertaking the RIT-T from TNSPs to AEMO would amount to partial extension of the current Victorian model for transmission planning to the other NEM jurisdictions. AEMO's declared network functions under the NEL, which to date have only been invoked in Victoria, enables AEMO (amongst other things) to plan, authorise, contract for, and direct, augmentation of the declared shared network.[43] These declared network functions only apply in adoptive jurisdictions, ie, those that state the functions apply in the relevant jurisdiction's application Act of the NEL.

It follows that, at a minimum, implementing an AEMO-led solution selection approach would require the consensus of the COAG Energy Council. Such consensus is required because legislative changes would be necessary in each jurisdiction (aside from Victoria) to enable AEMO to conduct RIT-T assessments. To ensure all actionable ISP projects are progressed through the same model, each jurisdiction would need to give effect to AEMO's declared network functions.

Importantly, invoking AEMO's declared network functions would be a pre-requisite for facilitating greater competition in all aspects of project delivery for large transmission investments. At present, competition in transmission project delivery occurs solely in relation to the construction element. The pre-requisite nature of AEMO's application of RIT-T assessments reflects that TNSPs are likely to be inherently unwilling to apply the RIT-T and then subsequently compete for the right to build, own and operate the preferred solution. It follows that an independent decision-maker is required to facilitate greater competition. This broader scope of competition across all aspects of project delivery has the potential to drive further efficiencies in the context of large transmission investments.

From a practical standpoint it is important to note that the relevant provisions of the NEL relating to AEMO's declared network functions mandate that, where they are invoked, AEMO must competitively tender transmission augmentations subject to the NER.[44] As a result, complementary amendments to the NER and NEL may be necessary to avoid these flow-on

[43] NEL, section 50C(1)(a).

[44] NEL, section 50F(3).

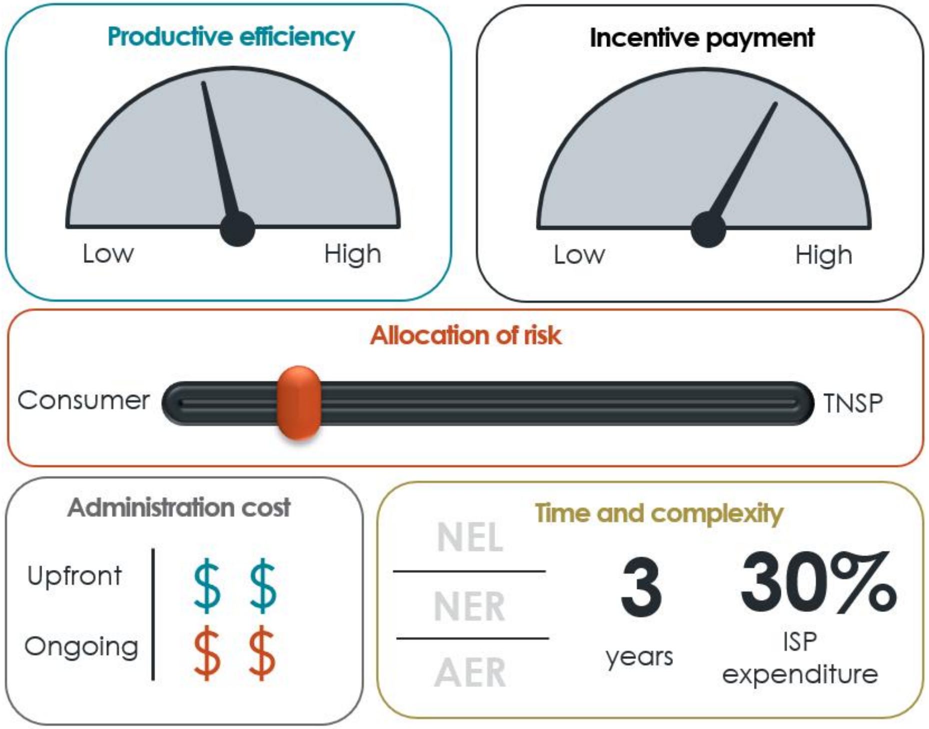
effects, in circumstances where the desired change is to maintain the status quo, beyond transferring responsibility for the RIT-T to AEMO.

5.2.3 Summary of our assessment

Figure 5.3 summarises our assessment – by reference to the analytical framework we develop in section 2 – of the AEMO-led approach to solution selection, relative to the existing approach. In our assessment, this alternative framework:

- would provide greater incentives for productive efficiency, since the financial preference faced by TNSPs would not influence AEMO's assessment of network and non-network options;
- would reduce the overall risk of inefficient solution selection (although this risk continues to be borne by consumers);
- is likely to be associated with:
  - a medium level of up-front costs, reflecting the need to upgrade AEMO's capability to apply the RIT-T to all actionable ISP investments across the NEM; and
  - a medium level of ongoing costs, reflecting the resource intensive nature of the ISP process and undertaking the RIT-T, although this would be offset to some extent since TNSPs would no longer be undertaking the RIT-T; and
- may take up to three years to implement, in light of the extent of the necessary changes to the NER and the NEL, implying that around 30 per cent of ISP expenditure would be captured under the approach.[45]

Figure 5.3: Assessment scorecard for AEMO-led solution selection



5.3 Sponsor-based competitive processes

We define sponsor-based competitive processes as involving developers competing to provide and build innovative solutions to needs identified by the

[45] Based on the specified timing, the discussion set out in section 2.4, and the assumption that forecast contingent project application dates reflect the final date in which projects can be influenced by options, we consider that the option would fail to capture the following projects: 'SA system strength remediation', 'Western Victoria transmission augmentation', 'QNI Minor', 'VNI Minor', 'Project EnergyConnect', 'HumeLink' and 'VNI West'.

independent system planner. Although not yet a term of art in the regulatory economics field, this model of competition for transmission infrastructure has gained prominence in the United States. Such a model of competition is one of two main ways by which regional transmission organisations in the United States have sought to comply with FERC Order 1000, which mandated competitive solicitation be used for transmission infrastructure. We discuss the other model for competition – bid-based competitive processes – in section 5.4.

In the remainder of this section we explain that this approach retains and expands on the essential benefit of the AEMO-led model. In particular, the ultimate decision maker is an independent, not-for-profit entity, so that financial incentives do not distort the decision-making process. Further efficiencies are encouraged by subjecting all aspects of the design and delivery of large transmission investments to competitive tension. Expanding competition in this manner offers the opportunity to attract innovative and cost-effective solutions to identified need.

However, the adoption of a sponsor-based competitive process would represent a significant departure from the existing framework in the NEM and, as such, would most likely involve a lengthy and complex implementation process.

5.3.1 AEMO selection of preferred solution through a competitive solicitation process

Implementing the sponsor-based model of competition would ultimately reduce AEMO's overall role in the planning process. In particular, AEMO would:

- be responsible for identifying system needs;
- no longer develop candidate options (under the status quo) or prescriptive solutions (under the AEMO-led model) to address identified needs; and
- select the preferred solution after soliciting competitive proposals from incumbent TNSPs and non-incumbent transmission developers.

Such a competitive solicitation process would occur by AEMO opening competitive windows in which qualified developers[46] could submit proposals that address the published identified needs. The length of the competitive window would depend on the need date of the project. For example, AEMO may operate (consistent with the PJM):

- long-term competitive windows – where developers can submit proposals within three months of the window opening for projects that do not need to be in-service within the next five years;
- short-term competitive windows – where developers can submit proposals within two months of the window opening for projects that need to be in-service between three and five years; and
- immediate-need competitive windows – where AEMO would hold the discretion to solicit solutions that have an in-service date within three years.

Where a project had a need date that would make it unsuitable for a competitive window, AEMO would retain the right to develop a prescriptive solution to the need, for implementation by the incumbent TNSP.

For projects that proceed under competitive solicitation, AEMO would be responsible for assessing the submitted proposals and selecting its preferred solution. The proponent of the preferred option would be awarded the right to finance, build, own and operate the solution (whether it be of a network or non-network form).

[46] Qualification would likely involve potential developers providing evidence of their technical capabilities in designing, construction, operating and maintaining transmission infrastructure.

It follows that this approach retains the advantages of the AEMO-led selection approach, ie, the risk of sub-optimal solution selection is reduced because the ultimate decision maker does not have financial incentives that may distort the selection process. The overall level of this risk is likely to be less than under the AEMO-led approach, because the incentive for developers to innovate is likely to be greater than that of AEMO.

5.3.2 Competitive solicitation likely to enhance efficiency and shift delivery risks to developers

The sponsor-based model of competition substantially increases the number of functions subject to competitive tension in the design and delivery of large transmission investments. By its nature, this model introduces competitive tension to all aspects of design and delivery. Although the current approach in the NEM provides scope for competitive tension over construction, the approach introduces competitive tension to the construction, finance, design and operation and maintenance of the preferred solution.

Exposing a greater number of elements of design and delivery to competitive tension is likely to enhance efficiency – thereby ultimately reducing electricity costs for consumers, as compared with the status quo. Competition across all aspects of project design and delivery provides greater opportunity to attract innovative and cost-effective solutions to identified needs. The fundamental rationale of the sponsor-based model of competition is that the savings to consumers from selecting an innovative and cost-effective solution to an identified need are likely to outweigh the savings from selecting the lowest cost implementation of a prescribed solution to that same need.

However, these savings can only be expected to accrue if the market for transmission solutions is workably competitive. Put another way, competitive processes are only a substitute for regulation where there is sufficient competition. It follows that the benefits of the sponsor-based model of competition have the greatest prospect of being realised where the market is sufficiently deep. The depth of a market for transmission assets likely depends on there being:

- an independent, not-for-profit organisation tasked with identifying the needs of the transmission network;
- a clear regulatory and legal framework that governs the role of the incumbent to ensure that it cannot use its market power to disrupt the competitive process;
- a sufficient scale of investment opportunities to encourage participation in the competitive process; and
- investments that are sufficiently separable from an incumbent's network to facilitate clear contracting arrangements.

The efficiency enhancing properties of a sponsor-based competitive process will also be strengthened if the contracting arrangements with the successful bidder can be established largely on fixed price terms.[47] Fixed price contracting arrangements provide strong incentives for productive efficiency.

On the one hand, fixed price contracts typically allocate much of the delivery risk to the developer. It follows that any overrun on the costs underpinning the proposal would imply that the revenues received under the contract would not be sufficient to cover the costs of the project.

On the other hand, if the developer can deliver the project at a lower cost than that informing their proposal, the fixed price they receive can be expected to generate more revenues than needed to cover the costs of the investment. This additional revenue amounts to a form of economic rent for the developer, albeit not in the same form of the incentive payments that accrue under the CESS.

[47] Although the price for such services in other jurisdictions are notionally fixed, adjustments are often provided for consumer price inflation, and may also include contingency clauses that allow the pricing terms to be reviewed in response to particular events.

5.3.3 Implementation would require substantial reform

The introduction of a sponsor-based competitive process would represent a substantial change to the existing transmission development framework in the NEM. Given the large scale nature of the change, implementing sponsor-based competition would involve a lengthy and complex process, particularly in light of the ISP reforms only having been recently completed.

Similarly to the AEMO-led solution selection option, the sponsor-based model transfers the solution selection role from TNSPs and to AEMO, in its capacity as the independent system planner. It follows that to facilitate this change, jurisdictions in the NEM aside from Victoria would need to pass legislation that invokes AEMO's declared network functions. To ensure consistency across all ISP projects, this change would need to be agreed to by the COAG Energy Council.

An additional complexity to adopting the sponsor-based approach is that there is presently no framework that would facilitate its operation under the NER. Although the NEL and NER set out the requirements of a competitive tendering process under AEMO's declared network functions, this process concerns prescriptive solutions assessed by AEMO in the RIT-T (see section 5.4.3). Put another way, the existing framework does not provide scope for competitive solicitation of solutions to identified needs. Rather, it provides scope for competition over the lowest cost implementation of an already prescribed solution. It follows that a rule change process would likely to need to occur to set out the framework by which:

- AEMO would undertake competitive solicitation for solutions to identified needs; and
- proposals received by AEMO in the relevant competitive windows would be assessed.

This process has the potential to take as long as four years, implying only 30 per cent of expenditure on near-term ISP projects would be captured under this option. By way of example, implementing the sponsor-based model in the PJM electricity system took four years, comprising:

- one year of consultation by FERC regarding the proposed rule change mandating competitive solicitation of transmission investments;[48] and
- three years for the PJM to develop its framework to implement a competitive solicitation process that complied with the new rule.[49]

5.3.4 Summary of our assessment

Figure 5.4 summarises our assessment – by reference to the analytical framework we develop in section 2 – of the sponsor-based competitive model. In our assessment, this framework:

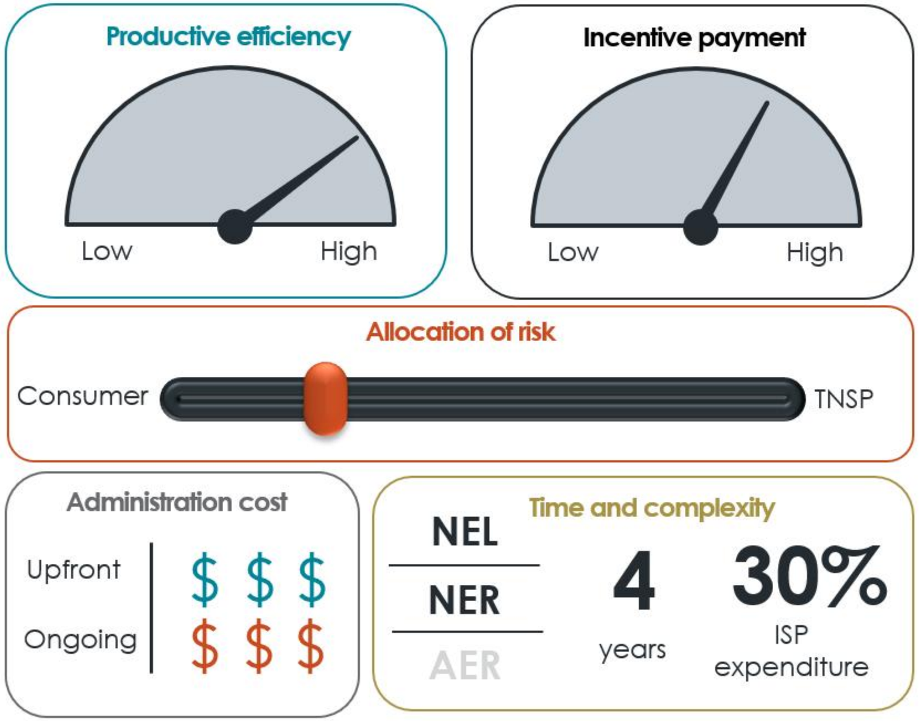
- provides strong incentives for productive efficiency and so may give rise to significant economic rents since:
  - competition across all aspects of project design and delivery provides greater opportunity to attract innovative and cost-effective solutions to identified needs; and
  - fixed price contracting arrangements provide strong incentives for productive efficiency;
- shifts project delivery risks towards developers through the contracting arrangements, although various contingences may mean that consumers are not fully insulated from the risk;
- is associated with:

[48] Consultation on the proposed rule change commenced in June 2010 while the rule came into effect in July 2011, see: FERC, *Docket No. RM10-23-000 | Transmission planning and cost allocation by transmission owning and operating public utilities,* 21 July 2011.

[49] PJM's first competitive solicitation window opened in January 2014.

  > high up-front costs since significant resources would need to be dedicated for establishing the framework and how it will be administered; and
  > high ongoing costs reflecting the need to continual assess proposals submitted as part of the competitive windows; and
- may take up to four years to implement given the likely need of complex changes the NER and NEL, meaning only 30 per cent of ISP expenditure would be captured under the approach.[50]

Figure 5.4: Assessment scorecard of the sponsor-based competitive process



[50] Based on the specified timing, the discussion set out in section 2.4, and the assumption that forecast contingent project application dates reflect the final date in which projects can be influenced by options, we consider that the option would fail to capture the following projects: 'SA system strength remediation', 'Western Victoria transmission augmentation', 'QNI Minor', 'VNI Minor', 'Project EnergyConnect', 'HumeLink' and 'VNI West'.

5.4 Bid-based competitive processes

Bid-based competitive processes involve developers competing to finance, build, own and operate specific projects that represent prescribed solutions developed by the independent planner to an identified need. The bid-based model of competition is used extensively, including in Victoria, in relation to offshore transmission in the United Kingdom and regional transmission operators (RTOs) in the United States that are required to comply with FERC Order 1000.

In the remainder of this section we elaborate on our perspective that AEMO-led selection is a prerequisite for introducing a broader application of bid-based competition to transmission investments in the NEM. In particular, under this potential reform model, AEMO would identify the need for investment and develop a prescriptive solution, which transmission developers would then compete by means of tender to build, own and operate.

This model of competition is likely to enhance efficiency, because a greater number of elements in the delivery of transmission investments are subject to competitive tension, ie, both the financing and operation functions, in addition to construction. Expanding the role of competition in this manner provides broader scope for prescriptive solutions to be delivered at least cost.

Further, since the NEL and NER already provide for the undertaking competitive tenders, much of the challenge of implementation would relate to providing sufficient resources to AEMO to undertake its current role in Victoria across the entirety of the NEM.

5.4.1 AEMO would run a tender process for a prescribed solution

We describe in section 5.2.2 that AEMO applying the RIT-T to determine the preferred solution to an identified need is a prerequisite for introducing a bid-based competitive process to the delivery of large transmission investments. It follows that, under this approach, AEMO would retain many of the roles and responsibilities we identify under the AEMO-led model, ie:

- identifying investment needs through the ISP; and
- developing prescribed solutions to address those needs through the RIT-T.

Under the bid-based model of competition, AEMO would take on the further responsibilities of determining whether a project is suitable for competitive tendering and, if so, administering the tender process.

Determining whether a particular investment is suitable for competitive tender can be a complex exercise and typically turns on:

- the size of the investment, since the cost of administering a tender process for a low cost project may be overly burdensome relative to the size of the anticipated benefits; and
- the separability of the investment from the incumbent's network, since:
  - > the complexity of the contracting arrangements increase with the degree to which the solution is meshed with the incumbent's network; and
  - > where an investment is meshed with the incumbent's network, there is greater scope for the incumbent to exploit its economies of scale and scope to bid in a manner that acts as a barrier to entry – thereby detracting from the competitive process.

Where an investment is deemed suitable for competitive tender, AEMO would solicit and assess bids to determine the party responsible for building, owning and operating the prescribed solution. This assessment typically encompasses dimensions of cost and capability, ie, selecting the lowest cost feasible implementation solution.

The successful bidder would be awarded the right to build, own and operate the prescribed solution, and would enter into a contract with AEMO, typically

30 years in length, for the provision of the transmission service. Such a contract would specify the level of revenue (as bid) to be received by the successful bidder as compensation for all the costs of providing the service, ie, capital costs, a return on capital and all future operating and maintenance costs.

Notably, the arrangements as described above largely reflect those that presently apply in relation to AEMO's administration of the bid-based competition regime for transmission projects in Victoria.

5.4.2 Competitive tendering likely to enhance efficiency and shift delivery risk to developers

The bid-based model of competition expands the number of large transmission investment functions that are subject to competitive tension. As noted above, the contract awarded to the successful bidder compensates for capital costs, the return on capital and future operating and maintenance costs. It follows that developers participating in the tender process are competing over construction, financing and the operation and maintenance of the asset. In contrast, the current approach in the NEM facilitates competition over construction only.

Expanding the elements of project delivery that are the subject of competitive tension is likely to drive efficiency enhancements and so reduce the cost of transmission services for consumers. Exposing a greater number of elements of project delivery to competition increase the scope for innovation to deliver the prescribed solution at least cost. For instance, enabling competition over financing provides a greater opportunity for developers to propose innovative funding models to lower the overall cost of delivery.

Analogously to the sponsor-based model of competition, the benefits of bid-based competitive processes can accrue only where the market is workably competitive, ie, where there is:

- an independent, not-for-profit organisation tasked with identifying the needs of the transmission network and developing a prescriptive solution to that need;
- a clear regulatory and legal framework that governs the role of the incumbent to ensure that it cannot use its market power to disrupt the competitive process;
- a sufficient scale of investment opportunities to encourage participation in the tender process; and
- investments that are sufficiently separable from the incumbent's network to facilitate clear contracting arrangements and thereby reducing the prospect of the incumbent using its economies of scale and scope to act anti-competitively.

The potential for strengthened efficiency under bid-based competitive processes are also supported by the generally fixed price nature of the contracting arrangements. As noted in the context of the sponsor-based model, these contracting arrangements:

- allocate most of the delivery risk to the developer, so that any cost overruns relative to those tendered would be such that the agreed revenue may be insufficient to recover the full costs of the investment; and
- provide scope for economic rent to be earned, since delivering the project at a lower cost than tendered would mean that the agreed revenues are greater than those required to recover the cost of the investment.

5.4.3 A competitive tendering framework exists in the NEL and NER

Competitive tendering is currently used in relation to transmission augmentations in Victoria and so already has a basis in the NEL[51] and NER.[52] Further, the competitive tendering framework provided for under the NEL and NER has been refined by means of AEMO-issued guidelines under the NER.

[51] NEL, Section 50F.

[52] NER, Chapter 8 Part H (8.11).

These competitive tendering arrangements apply by virtue of jurisdictional legislation that adopts AEMO's jurisdictional functions but which, to date, has only occurred in Victoria. Extending the existing framework for competitive tendering to the NEM more broadly would require the remaining NEM jurisdictions to pass legislation that invokes AEMO's declared network functions. Such a change would require the agreement of the COAG Energy Council to ensure that all ISP projects are subject to the same framework.

Adopting a framework with an existing basis in the NEM would shorten the timeframe and so reduce the cost of implementation. In particular, there would be no need to dedicate the resources to developing a framework for competitive tendering since one is already in place. Accordingly, the main challenge would be to secure agreement for expanding AEMO's planning role to be fully national, and for AEMO to be sufficiently resourced to undertake this task.

Further, the presence of an existing framework means that many of the conditions required to facilitate effective operation of the competitive process are in place. By way of example, features of the existing Victorian model include:

- AEMO as the independent planner to identify investment needs and develop prescribed solutions to those needs;
- criteria for determining whether a particular investment is suitable for competitive tender, ie:
  - > the cost of the project is sufficiently large (an estimated cost of over $10 million);[53] and
  - > sufficient separability from the incumbent's network;[54] and
- rules governing the conduct of the incumbent to facilitate the competitive tendering process.[55]

Despite these structural features facilitating competition, there remain concerns as to whether the existing experience of competitive tendering is indicative of a workably competitive market. By way of example, AusNet Services (the incumbent TNSP) had won 13 of the 15 tenders issued up to 2012.[56] However, we understand that more recent tenders have attracted increased number of more active bidders (including the incumbent).

We understand that the relatively low number of bidders participating in the earlier Victorian tender process likely reflects the limited number of contestable opportunities currently available in the NEM, which are not sufficient for many businesses to maintain a tendering and project team to respond to similar opportunities. Further, the size of the projects to date are unlikely to have been sufficient to attract interest from international developers – until recently, over the past 15 years a total of only $100 million worth of investment has been subject to competitive tendering.[57]

The apparently limited depth of the market for developers of transmission augmentations to date warrants caution as to the prospect of a competitive process producing benefits for consumers. In the absence of a sufficiently competitive field of bidders, an incumbent TNSP may be able to submit a price that would otherwise be higher than the regulated outcome and still win the tender.

However, we note that the pipeline of actionable ISP projects represent fundamentally different investment propositions to those that have previously gone through the Victorian competitive procurement process. It is likely that

[53] NER, Rule 8.11.6(a)(1) and NER, Rule 8.11.3 (definition of 'relevant limit').

[54] NER, Rule 8.11.3 (definition of 'separable augmentation')

[55] NEL, 50E(4) and (5). These provisions attract civil penalties if breached

[56] AEMC, *Transmission Frameworks Review,* Second interim report, 15 August 2012, p 80.

[57] AusNet Services, *Customer advisory panel | Presentation on the 2023-27 transmission revenue reset,* 29 August 2019, p 41.

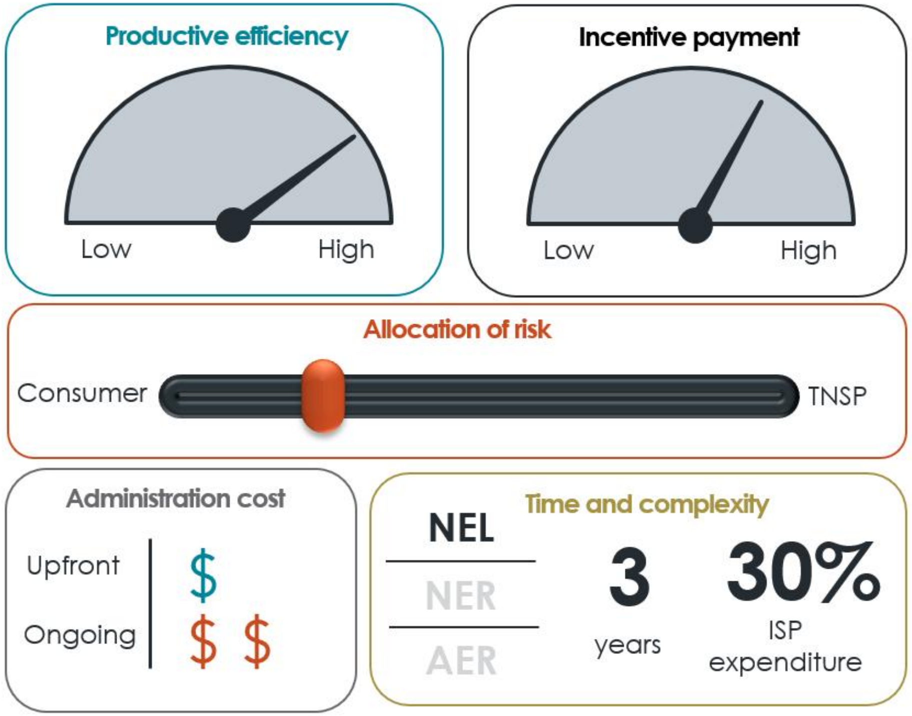
the scale and frequency of the contemplated ISP projects may be able to attract a much greater number of transmission developers.

5.4.4 Summary of our assessment

Figure 5.5 summarises our assessment – by reference to the analytical framework we develop in section 2 – of the bid-based competitive model. In our assessment, this framework:

- provides strong incentives for productive efficiency and so provides scope for material economic rents since:
  - expanding competition to include project financing and operation and maintenance provides a greater opportunity for low cost implementation of the prescribed investment; and
  - the fixed price contracting arrangements provide strong incentives for productive efficiency; and
- project delivery risks are shifted towards developers due to the nature of the contracting arrangements, although various contingencies mean that consumers are not insulated from risk;
- is associated with:
  - a low level of up-front costs, since there is an existing framework for competitive tendering in the NEL and NER, meaning these costs predominantly involve expanding AEMO's resource capability to conduct planning across the NEM; and
  - a medium level of ongoing costs, reflecting the role of AEMO in developing investments to be tendered and assessing the bids received; and
- may take up to two years to implement due to the need for legislative changes to apply competitive tendering across the NEM, implying that around 30 per cent of ISP expenditure would be captured under the approach.[58]

Figure 5.5: Assessment scorecard of the bid-based competitive process



[58] Based on the specified timing, the discussion set out in section 2.4, and the assumption that forecast contingent project application dates reflect the final date in which projects can be influenced by options, we consider that the option would fail to capture the following projects: 'SA system strength remediation', 'Western Victoria transmission augmentation', 'QNI Minor', 'VNI Minor', 'Project EnergyConnect', 'HumeLink' and 'VNI West'.

5.5 Implementation-based competitive processes

In this section, we draw on the experience of commercial procurement to provide a potential option for the regulatory treatment of large, discrete transmission projects. In particular, we note that engineering, procurement and construction management (EPCM) contracts are often considered to be a response to the effective management of large projects that require flexibility, collaboration and innovation. One means of expanding the potential for competitive tension in the delivery of large transmission projects would be for an externally appointed project manager to manage the efficient procurement of an AEMO-preferred solution, as distinct from this process being managed directly (or the manager being appointed) by the TNSP.

This potential option does not draw on regulatory approaches elsewhere, ie, we are not aware of any regulatory jurisdictions that seek to distinguish the role of the project manager from that of the financing and ownership of transmission infrastructure. It follows that there are likely to be some risks in adopting an approach that is untested and that it would be helpful to draw to a greater extent on commercial practice to ensure that such an approach would be practicable in a regulatory context.

Nevertheless, taking into account that:

- transmission procurement arrangements in the NEM appear to lag those that have developed in other highly respected jurisdictions over the past decade; and
- significant, near term reform may be challenging to achieve,

in our opinion this option warrants deeper consideration.

5.5.1 AER selects project manager to implement preferred solution

An implementation-based competitive process would begin with an AEMO-led solution selection process, with AEMO undertaking the RIT-T and identifying a well-defined solution that is capable of being competitively tendered.

Under the existing arrangements, the project manager role defaults to the TNSP sponsoring the relevant investment project. In preparing a contingent project application, TNSPs have substantial discretion as to how they seek to implement a project and inform their estimates of cost. Under the NER, the AER must approve proposed contingent capital expenditure that is efficient.

By contrast to the existing arrangements, under an implementation-based competitive process, once the preferred solution is identified, the AER would hold a tender to identify a project manager to manage the implementation of the preferred solution. We expect that such a tender would seek to identify a manager:

- with substantial experience in managing the construction of similar large infrastructure projects; and
- willing to accept fee and incentive arrangements (for example, an expenditure baseline) that drive the most value for consumers.[59]

We discuss the potential form of such fee and incentive arrangements in greater detail below.

A tendering arrangement of this form would replace the existing contingent project process. Once selected, the project manager would take steps to implement the project, working in consultation with (and being informed by) the TNSP.

[59] We note that similar arrangements could already be adopted under the existing monopoly approach to procurement, with the TNSP selecting the project manager. However, the incentives of a TNSP to agree to innovative fee and incentive arrangements for project managers ultimately depend on the TNSP's objectives and whether such incentive payments would be accepted as efficient and prudent costs.

When the project is complete, the assets would be owned and operated by the TNSP, with the actual cost of the assets and the fees and incentives paid to the project manager rolled into the RAB to be recovered from consumers over the life of the project.

We explain at section 5.2 above that an AEMO-led solution selection approach would require the consensus of the COAG Energy Council. To ensure all actionable ISP projects are progressed through the same model, each jurisdiction would need to give effect to AEMO's declared network functions. There would also likely be consequential changes to the NEL and the NER to implement these tendering arrangements.

5.5.2 Providing incentives to procure the project efficiently

The appointment of a project manager may not appear to resolve the problem of providing incentives for efficient investment, since it largely shifts the role of project manager from the TNSP to a contracted third party. However, such a shift may give rise to benefits where:

- there is significant scope for benefits arising from innovation in implementing a project; and
- there is reason to believe that a contractor might be more likely than a TNSP to adopt some form of innovation in implementing a project.

There may be significant scope for innovation in implementing a project, even where the form of the solution has been narrowly identified by AEMO. Innovation might be expected to give rise to reductions in costs relating to management, operating and technology choice in implementing a solution.

Investments in innovation are risky, and may give rise to the increased prospect of cost overruns. It follows that one of the challenges in providing effective incentives to TNSPs to innovate in project management is that:

- across its various functions, a TNSP tends to be a low-risk business with a preference for low-risk approaches; but
- in relation to the project management function, there may be benefits if the TNSP were able to take more innovative, high-risk approaches.

By their nature as regulated utility businesses, TNSPs tend to be risk averse, with an institutional preference for using well-tested techniques that minimise cost risk. Given the regulatory framework within which they operate, TNSPs can achieve a greater degree of certainty over their profitability by adopting less risky implementation approaches.

It follows that the appointment of a project manager may serve to introduce a party with less institutional aversity to innovative approaches. This offers both risks and opportunities, which stem from the relatively small scale of management fees as compared to the size of the project a manager is responsible for implementing. This asymmetry in scale means that the magnitude of any potential under-or over-spending may be many times greater than the base fee that the project manager earns. This raises potential difficulties in limiting significant under-performance but may also can provide very highly geared incentives for cost reductions.

Mitigating these risks to some extent is that project management is a distinct, specialist function, for whom suppliers can be presumed to have a strong, long term interest in performing well.

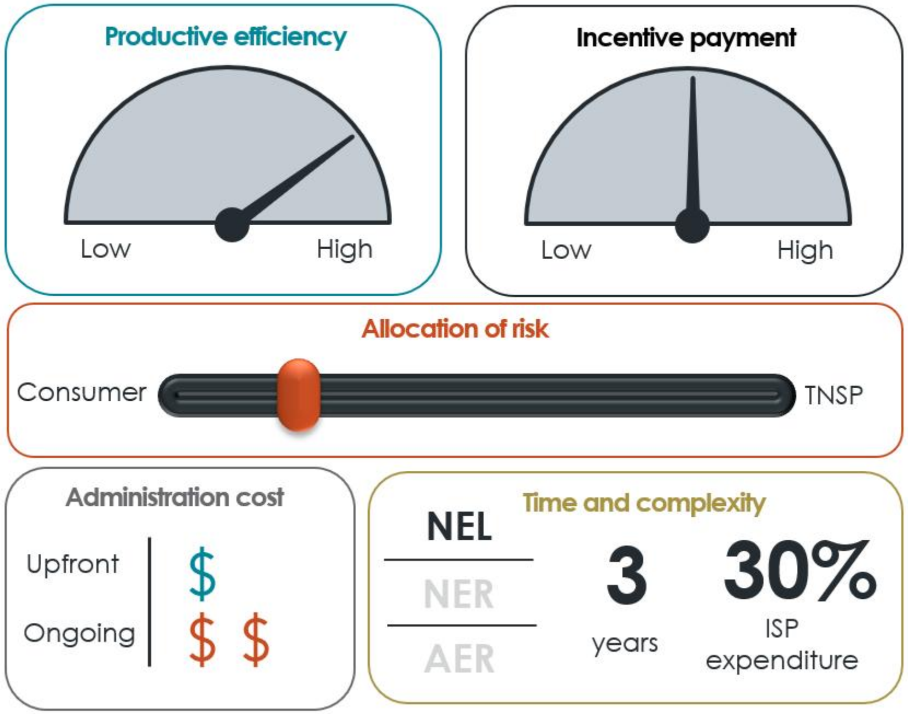
However, the effect of these arrangements is also likely to shift the allocation of risks more in the direction of the consumer. By comparison to the existing arrangements in which the TNSP is asked to shoulder part of the risk that the project is inefficiently implemented, it is likely that less of this risk could be borne by a project manager.

5.5.3 Summary of our assessment

Figure 5.6 summarises our assessment – by reference to the analytical framework we develop in section 2 – of the implementation-based competitive model. In our assessment, this framework:

- provides strong incentives for productive efficiency in relation to project implementation, and may be associated with lower economic rents since the project manager may require lower incentive payments than the TNSP;
- shifts a greater proportion of the risk that the project will be inefficiently implemented onto the consumer, since the project manager is less able to manage the risk of cost overruns than the TNSP;
- is associated with:
  - a medium level of up-front costs, reflecting the need to upgrade AEMO's capability to apply the RIT-T to all actionable ISP investments across the NEM and for the AER to set out guidelines on the arrangements for tendering; and
  - a medium level of ongoing costs, reflecting that although AEMO and the project manager take on additional roles under this option, these are roles that are no longer undertaken by the TNSP; but
- may take up to three years to implement due to the required changes to the NER and the NEL, meaning 30 per cent of ISP expenditure will be captured under the approach.[60]

Figure 5.6: Assessment scorecard of the implementation-based competitive process



[60] Based on the specified timing, the discussion set out in section 2.4, and the assumption that forecast contingent project application dates reflect the final date in which projects can be influenced by options, we consider that the option would fail to capture the following projects: 'SA system strength remediation', 'Western Victoria transmission augmentation', 'QNI Minor', 'VNI Minor', 'Project EnergyConnect', 'HumeLink' and 'VNI West'.

A1. Commercial procurement of large investments

In Australia and in other jurisdictions, the introduction of competitive tension has been one of the most important means of promoting increased incentives for the efficient provision of infrastructure.

The Hilmer report laid the foundations for de-regulation of public and regulated monopolies in Australia. It noted that competition can enhance all types of efficiencies: [61]

- with respect to productive efficiency:

  > Competition can enhance technical efficiency by, for example, stimulating improvements in managerial performance, work practices and the use of material inputs.

- with respect to allocative efficiency:

  > Competition tends to increase allocative efficiency, because firms that can use particular resources more productively can afford to bid those resources away from firms that cannot achieve the same level of returns.

- with respect to dynamic efficiency:

  > Competition in markets for goods and services provides incentives to undertake research and development, effect innovation in product design, reform management structures and strategies and create new products and production processes.

It follows that, as a matter of economic principle, the introduction of competition in a market may provide scope for significant benefits.

Except in Victoria, the regulatory arrangements in the NEM operate so that the incumbent TNSP is treated as the monopoly provider of prescribed and negotiated network services. We explain in sections 5.3 and 5.4 that, in some other jurisdictions, competitive tension is used to:

- select the best solution for power system problems, whether through transmission investment or by other means; and/or
- determine who builds, owns and operates the preferred solution and the compensation for these activities.

Currently in the NEM, competitive tension is used in the delivery of transmission projects. We understand that TNSPs do not usually construct large transmission projects themselves but tender out construction of large projects to third party contractors. The result of these arrangements is that the build costs of a transmission project are, to the extent that competition is preferred, subject to some competitive tension, but not necessarily other aspects of the project.

The efficient procurement of large investments is not a problem that is unique to the economic regulation of TNSPs, or even economic regulation generally. This is a problem that is often faced when constructing significant new infrastructure, whether for private or for public use. In this section, we draw from private sector experience of how to procure large construction projects.

In a commercial context, principals (ie, clients or owners) delegate tasks to agents (contractors, suppliers) for a myriad of reasons, eg:

[61] Hilmer, F, Rayner, M and Taperall, G, *National competition policy review*, 25 August 1993, p 4.

- in the context of public private partnerships, research on behalf of the Australian government considered that:[62]

> [benefits] include the potential for value for money, early project delivery, gains from innovation, obviating the need to borrow to finance infrastructure investment, and access to improved services.

- to gain access to mutually beneficial trade, due to efficiency gain from transferring tasks to specialist agents, which are better equipped to deal with project risks; and
- due to resource limitations.

However, whilst there are benefits to delegating tasks, delegation introduces difficulties in that an agent's objectives may diverge from the principal's.[63] This can be viewed as an issue of control. For instance:

- if the principal were to undertake the task itself it would have complete control of the project and objectives would be completely aligned; whereas
- if the principal delegates the task, it has mitigated control with the possibility of incentive divergence.

In such a context, a contract is a tool for formally sharing risks and producing incentives which align the interests of the principal and the agent, as well as promoting risk mitigation. Ultimately, there are a range of possible contract combinations, with the most suitable option depending on a range of factors, including timeframe and budget. Within the broader procurement process there are many opportunities for variation, which leads to numerous trade-offs faced by a principal.

In this section, we discuss these trade-offs and how they inform the development of construction contracts. We describe:

- the phases involved with delivering a large project;
- the taxonomy of approaches to procurement and how these are selected;
- the economic trade-offs that result from competitive procurement; and
- the lessons from prominent case studies.

Where appropriate, the discussion focuses on the issues faced within the context of large construction and large transmission projects.

A1.1 The phases of a project and project inputs

Large infrastructure projects are characterised by technical, organisational, and environmental complexity, involving numerous steps to develop from early planning to asset commissioning and operation. This complexity is illustrated in Figure A1.1 below, which captures some of the different stages and considerations to be made within a large project.

[62] Webb, R and Pulle, B, *Public Private Partnerships: An Introduction: Research Paper no.1, 2002-03*, Economics, Commerce and Industrial Relations Group, Parliament of Australia, 2002.

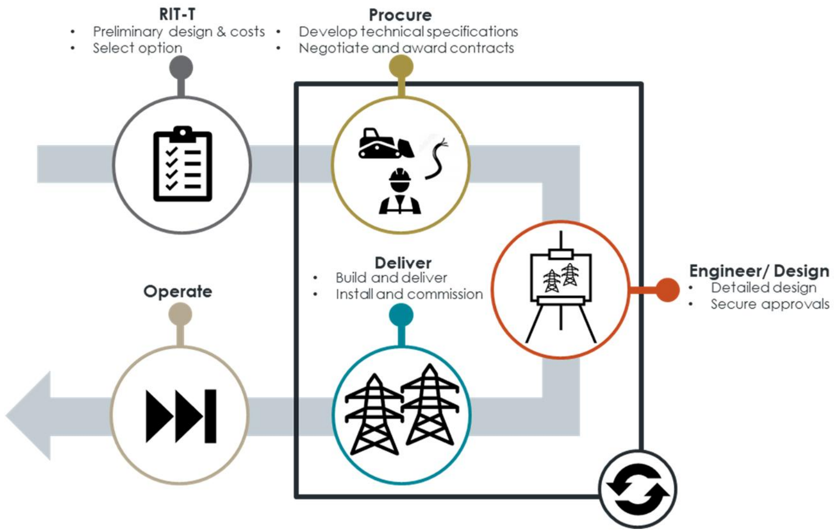
[63] Laffont, JJ and Martimort, D, *The Theory of Incentives: The Principal-Agent Model*, Princeton University Press, New Jersey, 2002.

Figure A1.1: Possible development stages for programs

Source: Parth, FR, Planning and controlling megaprojects, Project Management Institute, North America, 2014

In the context of a simple transmission project, the development stages can be described as beginning at the initial selection of a transmission solution in the ISP and continuing until the project begins operating, ie, as illustrated in Figure A1.2.

Figure A1.2: Transmission development stages



Source: AEMO, Victoria to New South Wales Interconnector Upgrade, Project Assessment Conclusions Report, February 2020, p 51.

From such a process, a range of task emerges, which include:

- build tasks – design, procurement, engineering, construction and project management; and
- planning tasks – enable effective building and project success by allocating responsibilities, and determining the requirements of the project, what to procure and how to procure it.

Whilst the importance of financing is not illustrated in the figure above, it is required to allow a project to continue through the process – if there is insufficient finance or it is too costly, the project would not be deemed feasible and either cease or face delays. As with other large infrastructure projects, large transmission projects rely on these inputs.

Although it is helpful to depict the project development process as a sequential and linear process, such as set out in Figure A1.1 and Figure A1.2 above, in reality this is not the case. Large projects experience in-project discoveries which necessitate innovation and flexibility. In the context of transmission projects, the implication is that between the RIT-T and asset commissioning is an iterative process of determining what inputs are needed, how the asset should be designed, and how the asset should be delivered.

Both generally and within the context of transmission, the complexities of moving from an 'identified need' (or opportunity) through to commissioning an investment require the involvement of numerous parties, which are identified and selected through procurement. Indeed, a myriad of benefits result from public and private sector procurement, such as:

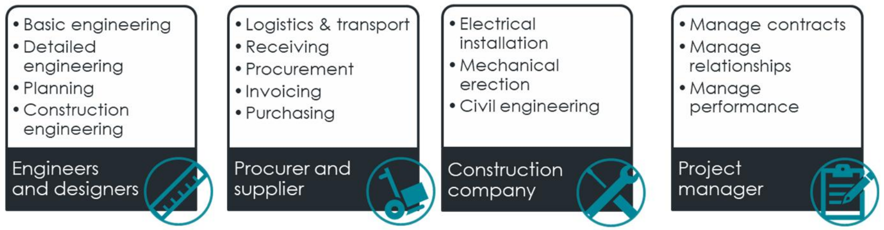
- value for money;
- expedited delivery;
- gains from innovation;
- overcome resource limitations; and
- risk mitigation.

A1.2 Contracting for large projects

Contracts are legally enforceable agreements between two or more parties that enable procurement. Principally, they allow the transfer of risk between parties, providing it to the party best capable of bearing it. For example, a firm which specialises in construction is likely better placed to handle associated risks than its client.

Further, contracts also work to align objectives of the contractor (agent) with that of the principal. Reflecting the range of tasks required to complete a construction project, contractors hired often include engineers and architects, procurement and supply chain experts, construction firms, and project managers – the roles of these parties are depicted in Figure A1.3.

Figure A1.3: Summary of contractors/roles required in a large project



Note: This provides a high level description of the different contractors that may be hired by a principal. There is also a role for commissioning the asset, eg, providing after-sales-service and testing and commissioning the asset. This may be included within the task of construction or can be separated.

Unlike small projects, large projects often necessitate many different contractors, subcontractors and advisors. Indeed, these complexities compound upon the incentive problems that are relevant to contracts (ie, that a principal and agent's objectives do not necessarily align). This leads to three contractual functions:[64]

- safeguard or control – alignment of objectives;

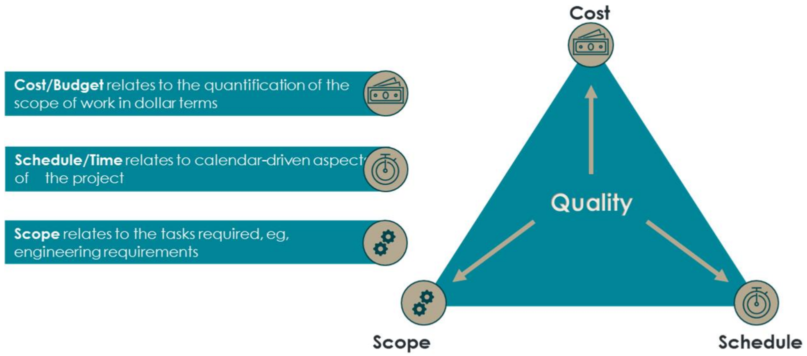
[64] Alberti, J, *An institutional economics approach to megaproject construction contracts*, Inter-American Development Bank, July 2019, pp 3-4; Gao, N, et al, *Addressing Project Complexity: The Role of Contractual Functions*, Journal of Management in Engineering, 34(3), 2018).

- coordination – coordinate interdependent tasks between different parties – establish roles and responsibilities; and
- adaptation function – need to face the inevitable incompleteness of the contract, relating to unforeseen changes.

These functions are extensions of the need to mitigate risk arising both at the time of contract drafting and throughout the life of the contract. Although contracts specify and allocate risks that are known at the time of drafting, realistically, and especially the case with large projects, there is a possibility that contracts will be incomplete. This risk necessitates resolution mechanisms, such as flexibility in contract design and the ability to utilise change orders.

A simple way of highlighting the issues faced by a principal in undertaking a project is the triple constraint theory of projects, which states that the success of the project is impacted by its budget, deadlines and features. This highlights that if a change in scope is necessitated due to circumstantial change (or realisation of previously unknown information), there will be either a change in cost or schedule – resulting in cost overruns or delays (likely both). This trade-off is highlighted in Figure A1.4 below.

Figure A1.4: The triple constraint theory of contracts



When faced with risk, a principal and contractor face a range of choices:

- **avoid** – remove scope from the project/contract, recognising that it will result in lost project benefits – the ultimate form of this is cancelling a project that is too risky;[65]
- **exploit** – increase scope to take advantage of possible upside benefits;
- **transfer** – find a party that is willing and able to bear the potential downside of the project and take responsibility for minimising overall project risk;
- **share** – find a partner to take responsibility for capturing potential upside in return for a proportion of the additional value created; and
- **accept** – involves continuing with the project as currently defined (with accepted levels of risk), monitoring changes in risks, and ensuring contingencies exist.

[65] For example, in September 2013 AngloAmerican released an announcement declaring that it would be pulling out of a joint venture to develop the Pebble Mine copper and gold project in Alaska, after spending $500 million, see: https://www.iol.co.za/business-report/companies/anglo-drops-out-of-pebble-project-1578398.

A1.3 Pricing methodologies

One consideration made when determining how to contract is the form of pricing and incentive scheme to be utilised. These vary from fixed price to cost-plus forms. It is important to note that a project is not restricted to a pricing scheme – different tasks at different stages of development can use different contracts with different schemes.

A1.3.1 Fixed price contracts

Fixed priced (lump sum) contracts offer the contractor a single price which does not change. In theory these transfer all risk to the contractor, and so provides the contractor will significant incentives to cut costs. However, this is far from reality due to:

- **litigation**, which means that a contractor can leverage additional costs, eg, the Sydney light rail project saw the fixed price increase by costs incurred after the contractor faced unforeseen obstructions to delivery; and
- **change orders**, ie, if the principal wants to allow change, the contractor will often (unless scope is to decrease) require additional allowance – which transfers risk back to the principal.

Due to the substantial changes that arise over the course of large projects, placing unnecessary constraints on costs and time allowance is not suitable:[66]

> nobody has ever paid less than the Lump Sum amount, and almost everybody has paid more, often considerably more.

Illustrating this truism, Box A1.1 below sets out the experience of the New South Wales government in contracting for the construction of the CBD and south east Sydney light rail line – a project that was nominally 'fixed price' but resulted in the government and the contractor sharing the impact of cost overruns on the project.

Box A1.1: CBD and south east Sydney light rail line

Opening for complete use on 3 April 2020, Sydney light rail – a 12.8km line from the City to its eastern suburbs – cost approximately $2.96 billion, exceeding the original budget of $1.6 billion by over $1.3 billion and was delivered over a year late.[67]

As part of the New South Wales government's transport strategy, the CBD and south east Sydney light rail was developed as part of a public private partnership.[68] The government awarded the project, which included the design, construction, operation and maintenance of the line and was originally valued at $2.1bn, to ALTRAC light rail consortium (ALTRAC).[69]

To select ALTRAC, the government undertook an evaluation process which led to the shortlisting of three consortia: ALTRAC, Sydney Connect and iLinkQ Sydney, although iLinkQ later withdrew from the process. To evaluate the successful project, the government utilised evaluation criteria including:[70]

- customer focused outcomes during operations;
- integrated design and optimised technical solutions;

[66] Parth, FR, *Planning and controlling megaprojects*, Project Management Institute., North America, 2014

[67] Emma Elsworthy, *Final stage of Sydney light rail opened remotely by minister as travel restrictions limit use*, ABC News, 3 April 2020; The Sydney Morning herald, *Sydney's light rail bill soars to at least $2.9 billion*, 22 November 2019; The Guardian, *Sydney light rail project blows out to $2.9bn, almost double original cost*, 23 November 2019.

[68] Transport for NSW, *Sydney Light Rail Public Private Partnership*, Contract summary, 25 August 2015, pp 2-3.

[69] Previously known as Connecting Sydney; Railway technology, *Sydney's $2.1bn light rail contract awarded to ALTRAC Light Rail*, 17 December 2014.

[70] Transport for NSW, *Sydney Light Rail Public Private Partnership*, Contract summary, 25 August 2015, p

- whole life asset management;
- commercial and financial acceptability to Transport for NSW; and
- risk adjusted cost.

ALTRAC subcontracted the task of constructing the light rail to Acciona, a Spanish construction firm. Within this role it faced numerous difficulties, one of which was that it had encountered unforeseen obstructions when digging.[71] As a result of these difficulties, Acciona entered a legal dispute with Transport for NSW which resulted in a '$576 million settlement over the extra cost of underground utility work along the project route.'[72]

Reviews of the procurement processes undertaken by the NSW government found issues. For example, in November 2016 the Auditor-General released a performance audit report highlighting that:[73]

- planning and procurement did not ensure maximum value for the state;
- costs were higher and benefits lower than in the approved business case and outstanding issues were present that should not have been; and
- incorrect assumptions had been used in the tender evaluation process when benchmarking value for money.

These issues culminated in a project that was both delayed and overly expensive, with costs of over $2.9 billion significantly exceeding the original budget of $1.6 billion.[74]

In any case, many fixed prices are not truly fixed. Adjustments may be built into the contract, such as for inflation or fuel costs. This acts to transfer the risk of these factors back to the principal.

Further, to compensate for risk faced the contractor will demand a risk premium. The consequence is that fixed price terms are more likely to be appropriate when overall risk is low – which is often not the case in large projects.

Table A1.1: Advantages and disadvantages of fixed price contracts

Advantages	Disadvantages
• In theory removes all risk from contractor • Very simple, allowing benefits when performance cannot be measured clearly and so incentives are difficult to design. Consistency and simplicity of contracts reduces the cost faced by potential contractors. Although benefits are limited with sophisticated parties.	• Incentive to complete low quality work, use low quality materials and cut costs • Litigation • Difficulty executing change orders without need to provide further cost allowances • Inflated price to reflect risk premium • Requires sufficient information to make it work

There are numerous variations of the pure form contract, including:

- firm-target fixed-price contracts – price target does not vary over the contract life;
- successive targets fixed-price contracts – price target is allowed to vary over the contract life, through revision; and

[71] Paige Cockburn, Sydney light rail contractor Acciona suing NSW Government; further delays to construction likely, ABC News, 7 April 2018.

[72] Oliver Probert, *Sydney Light Rail legal stoush ended with $576m settlement*, Railexpress, 4 June 2019.

[73] NSW Public Accountability Committee, *Impact of the CBD and South East Light Rail Project*, Report 2, January 2019, p 8.

[74] The Guardian, *Sydney light rail project blows out to $2.9bn, almost double original cost*, 23 November 2019.

- fixed-price award-fee contracts – a bonus is added to the fixed fee price at the end of the contract if work is deemed deserving.

A1.3.2 Cost reimbursement (cost plus) contracts

At its most basic, a cost reimbursement contract pays the contractor allowed expenses to a set limit, with additional payments. This links costs faced with the payment from the principal, and so shares risk between parties. Generally, this is combined with a payment, ie, either an incentive or an award.

Notably, the limit could be set to cover all costs incurred over the project – this was applied by the British Airports Authority (BAA) in the development of Heathrow terminal 5, which we discuss in more detail at section A1.4.9 below. Notably, such a decision places great emphasis on using incentives to prevent cost overruns.

Table A1.2: Advantages and disadvantages of cost reimbursement contracts

Advantages	Disadvantages
• Improves alignment of objectives • Promotes quality • Reduces risk of contractor defaulting • Limit on amount spent can cap contractor expenditure	• Can increase risk faced by contractor • Can promote resistance to contract changes, and thus reduce flexibility • If incentives are not well managed, face overspend issues

A1.3.3 Cost plus incentive contract

In addition to the standard reimbursement of a portion of the costs faced by the contractor, incentives are paid. These reflect payments to the contractor for performance, ie, the mitigation or avoidance of risk. For example, incentive payments might be made to a contractor for meeting price and schedule targets. By doing this, the contract acts to align the objectives of the contractor and principal.

However, this is only possible to the extent that performance is measurable. Even where this is feasible, it may still be difficult to distinguish outstanding performance from normal performance, which creates difficulties in providing different scales of incentive.

Caution is necessary when understanding the implication of joint incentives. For example, if a project has overspent and is delayed, incentives to both cost-cut and meet schedule constraints could see reduced quality work. Another issue with such contracts is the limiting effect that may be had on scope changes which impact incentive requirements. For instance, if the contractor fears that an incentive will not be rewarded due to a scope change they may reject the scope change.

A1.3.4 Cost-plus award contract

In addition to the standard reimbursement of a portion of costs faced by the contractor, a cost-plus award contract provides an award amount that the contractor may earn (in part or in entirety) upon performance of the contract. The amount selected would need to be sufficient to provide motivation for cost, schedule, and technical performance.

This allows for significant flexibility as the award is not contingent on goals set at the time of contracting. However, there are limited incentives for cost control. This thus allows significant potential for owner influence, in line with increased responsibility. To this end, this contract is useful when the scope is poorly-defined and the contractor is known and trusted. As a result, these require significant additional administrative and management effort.

A1.4 Contracting structures

Due to the benefits derived from procurement, its use is not limited to within construction, rather it is also used for ownership and operation of assets. This is commonly undertaken by governments which present a problem, or a solution to a problem to the market, and seek private involvement. This results in a range of project delivery methods, which are combinations of the following:[75]

- design;[76]
- build (procure, engineer/design and construct);
- commission;
- own;
- maintain;
- lease;
- transfer;
- operate; and
- finance.

Depending on what the principal's problem is, a different project delivery method is applicable. In the context of the private sector, the most relevant considerations are design and build, whilst for government this is more inclusive. Naturally, there are varied incentives that emerge from different project delivery methods, eg, a build-own-operate contract will create greater incentive for the contractor to strive for high quality than a contract that is build-only, because the contractor will internalise potentially higher operating costs derived from low quality.

[75] Additional considerations may include lease and transfer.

[76] Can be included as engineering within the build phase. However, is often disaggregated to represent position in delivery process.

In combination with the pricing structures, this leads to a range of possible contracts, which are discussed below. Ultimately, these govern the relationships between parties and the scope for party involvement.

A1.4.1 Build-own-operate-transfer contracts

Build own operate transfer (BOOT) contracts involve a contractor receiving the role of building, owning and operating a piece of infrastructure for a given period of time. At the end of the prescribed time period, the contractor transfers ownership (at no cost) back to the principal.

BOOT contracts are commonly used by the public sector as a form of public private partnership as:

- they provide a new source of funding and reduce public cost for infrastructure development; and
- they draw on innovation and efficiencies from the private sector.

However, these contracts also face limitations. For example, BOOT contracts will only work for projects which are sufficiently large to attract investment and can be associated with high transaction costs. A further risk, which can be caused by inadequate due diligence (or adverse selection) or the uncertainties inherent in large projects, is that there may be low realised demand for the solution constructed.

Demand risk, which emerges within BOOT contracts and other contracts which involve transferring asset ownership, is the risk that demand is insufficient to meet financing costs, ie, that financing costs may increase or realised demand may fail to meet forecasts.[77] An over forecast of demand can be explained by numerous factors, including:

[77] Including Sydney's Cross City and Lane Cove Tunnels, Brisbane's River City Motorway, and the Alice Springs to Darwin Railway.

- **the winners curse** – a party that bids more competitively will likely have forecast higher benefits (or lower costs); and
- **misleading information release by the procurer** – asymmetry of information can result in proposals relying on bullish forecasts, eg:
- the forecast direct demand may be excessive; and
- the ability of the network to support use cases may be lower than anticipated.

The implication of a benefit shortfall depends on the form of financing and ownership employed. For example, in the case of private ownership, a benefit shortfall may not affect end users as the infrastructure has already been developed. However, the developer may become insolvent, as occurred in the case of the Alice Springs-Darwin Railway and Clem7 tollway – Box A1.2. This may cause dynamic inefficiencies if repeat investments are desired, eg, the repeated negative experience of tollway developers in public private partnerships has 'soured the private sector's appetite' for these opportunities.[78]

These further consequences of shortfalls are highlighted by the prevalence of class actions following unrealised traffic forecasts made by government, operators and associated advisors. This suggests that:

- forecast benefits must be cautiously generated in the presence of external investors;[79] and
- although the private sector may bear the instant effects of insufficient demand, other parties may bear some responsibility.

There are numerous methods that can be used to mitigate these issues, eg:

- benefit risks should be borne by parties which are most apt to bear them, which may include the government;
- using appropriate selection methods to mitigate the likelihood of an incapable party winning a tender; and
- completing construction in stages to reduce the cost of lower than realised demand.

Box A1.2: Demand shortfalls in PPP and BOOT contracts

Case 1: Alice Springs to Darwin Railway

The 2,979km Adelaide to Darwin railway line was completed in September 2003 after FreightLink, which was subcontracted to build and operate the 1,420km Alice Springs to Darwin railway, completed construction of its $1.2 billion segment.[80] Whilst it successfully built the Alice Springs to Darwin railway, Freightlink went into voluntary administration after low demand resulted in it being unable to meet interest payments.

In June 1999, the AustralAsia Railway Corporation, which managed the 1,420km Adelaide to Darwin railway line project on behalf of the Northern Territory and South Australian governments, awarded a 'Build, Own, Operate and Transfer' contract to the Asia Pacific Transport Consortium (APTC).[81] APTC subsequently contracted FreightLink to build and operate the project, and so transferred the role of both developing and operating the 50 year concession agreement (which terminates in 2054).

[78] Rod, Morrison, *The Principles of Project Finance*, Gower Publishing Limited, England, 2012, p 304.

[79] Under the ISP, forecast demand risk or the risk of underutilised assets is faced by consumers. As AEMO is responsible for forecasting demand, and to the extent that investment is actively encouraged, this allocation is not unreasonable.

[80] The Advertiser, *FreightLink-owned Adelaide-Darwin railway to be sold to US company Genesee & Wyoming*, 9 June 2010.

[81] See: the AustraliAsia railway corporation website, available: http://www.aarc.com.au/aarc/news/newsletters_factsheets/aarc/brochure_may2000/, accessed on: 26 May 2020; Michael Smith, *Owner of Adelaide to Darwin rail back on block*, AFR, 27 January 2010.

Building the Alice Springs-to-Darwin railway cost approximately $1.2 billion,[82] and was funded with $475 million from federal, Northern Territory and South Australian government funds, and a $900 million investment by Freightlink, approximately half of which was debt.[83] Construction spanned from July 2001 and September 2003.

After opening for utilisation, Freightlink operated well below its profitable capacity.[84] This was the consequence of numerous factors, including:[85]

- **poor quality of the connecting network** – portions of the network south of Alice Springs were of insufficient quality to move high mass freight at high speeds, leading to periods of reduced speed of trains and instances of locomotive and wagon damage;[86]
- **insufficient track quality to carry minerals** – the track was built as a lightweight track, and so it had reduced ability to carry minerals without facing significantly increased maintenance costs; and
- **competition from road-side transport** – road side transport offered a more convenient, expedited and similarly priced solution, leading to freight companies either continuing to use or reverting to road side transport.

The combined impact was that there was low demand for the service, with the AFR stating that:[87]

> …three of the five weekly rail services to Darwin carry little freight, and four out of the five return trips are empty

On 6 November 2008, Freightlink went into voluntary administration reflecting the inability of internal stakeholders to reach agreement with creditors on the terms of a sale of the business. Genesee & Wyoming Australia later (June 2010) purchased its assets, including the 50-year lease on the Adelaide–Darwin railway, for $334 million.[88]

Case 2 – Clem7, Brisbane (public private partnership)

Completed by RiverCity Motorway in March 2010, the M7 Clem Jones Tunnel (Clem 7)[89] is a 4.8km tunnel under the Brisbane River which completes a 6.8km long privately financed tollway system linking five major Brisbane roads.[90] Whilst Clem 7 was completed on time and on budget – costing approximately $3 billion to construct – lower actual traffic volume than forecast led to RiverCity Motorway being placed into receivership in early 2011.

In April 2006, the RiverCity Motorway consortium, which included Leighton Contractors, Baulderstone Hornibrook, Bilfinger Berger and ABN AMRO Australia, became the preferred tenderer of the Clem7.[91] The consortium raised money to finance, design, build and operate Clem7 through a combination of debt and equity, including:[92]

- $690 million, raised via an initial public offering; and

[82] Michael Smith, *Owner of Adelaide to Darwin rail back on block*, AFR, 27 January 2010.

[83] Jennifer Perry, *Adelaide to Darwin railway to exploit future opportunities*, railexpress, 4 November 2009.

[84] Beth Quinlivan, *Tracks put to the test*, AFR, 31 March 2005.

[85] Beth Quinlivan, *Tracks put to the test*, AFR, 31 March 2005.

[86] Whilst this issue was largely resolved, it took the majority of 2004 and so reduced the railways output relative to possible expectations.

[87] Beth Quinlivan, *Tracks put to the test*, AFR, 31 March 2005.

[88] ABC News, *Adelaide-Darwin railway sold to US company*, 9 June 2020.

[89] Previously known as the North South Bypass Tunnel.

[90] The Pacific Motorway, Ipswich Road, Lutwyche Road, the Inner-City Bypass and Shafston Avenue at Kangaroo Point.

[91] The Sydney Morning Herald, *$724m float for toll road firm RiverCity*, 14 June 2006; The Sydney Morning Herald, *RiverCity lists at discount on ASX*, 3 August 2006.

[92] Additional funds were raised via government contribution, with payments to ultimately be made by the rate payer. The Sydney Morning Herald, *RiverCity lists at discount on ASX*, 3 August 2006; Tony Moore, *The Clem7, by the numbers*, Brisbane times, 28 February 2010.

- $1.3 billion, raised via debt.

On 14 June 2006, RCM chairman Bob Morris stated that the IPO opportunity was unique and would allow investors to 'benefit from the maximum exposure' to the Clem7 project:[93]

> The NSBT is a unique opportunity to invest in Queensland's first privately owned toll road, in Australia's fastest growing metropolitan centre…
>
> As a single purpose greenfield project, investors have the opportunity to benefit from the maximum exposure to potential capital growth from an investment re-rating that typically occurs once construction is completed and traffic ramp-up begins…

Whilst this exposure was to the upside potential of the project, it was also to the downside risk. This downside risk was realised when, after the tunnel opened for use in March 2010, actual traffic was much lower than forecast traffic – whilst originally more than 100,000 vehicles were forecast to use the Clem7 per day by 2011,[94] fewer than 27,000 vehicles passed through the tunnel per day as at February 2011.[95] Regarding the risk associated with not meeting forecasts, the Brisbane Times reported that Lord Mayor Quirk consider that:[96]

> …the risk was borne by RiverCity Motorway, the toll consortia that has won the 45-year licence to build and operate Brisbane's first traffic tunnel...
>
> If the numbers don't come in that is a risk absorbed by the consortia, by the companies…
>
> The predictions made by the companies are at their own risk. That is the competitive nature of the private sector.

This discrepancy in actual and forecast traffic was partially attributed to 'aggressive' forecasting, ie:[97]

- traffic estimates provided to RiverCity Motorway by Maunsells/AECOM (2006) predicted an average of 136,188 vehicles per day using the tunnel by 2026; and
- traffic estimates completed by Sinclair Knight Merz and Connell Wagner on behalf of Brisbane City Council (February 2005) predicted 82,000 vehicles using the tunnel by 2026.

The consequence of low realised traffic was that toll payments were significantly lower than originally forecast, which led to RiverCity Motorway receiving insufficient revenue to fund its interest payments. This led to RiverCity Motorway entering receivership in February 2011.

In 2013, the tunnel was acquired by Queensland Motorways in a $618 million deal with the RiverCity Motorway receivers, representing a reduction from the construction costs of approximately $2.4 billion.

In June 2016, RiverCity IPO investors secured $121 million in damages following a successful class action against traffic forecaster AECOM and RiverCity MotorWay. The class action was based on misleading traffic

[93] The Sydney Morning Herald, *$724m float for toll road firm RiverCity*, 14 June 2006; Louise Brannelly, *Clem7 owners RiverCity Motorways go into receivership owing $1.3bn*, The Courier Mail, 25 February 2011.

[94] Matt O'Sullivan, *Bankers pull the pin on RiverCity*, Brisbane Times, 25 February 2011.

[95] Matt O'Sullivan, *Bankers pull the pin on RiverCity*, Brisbane Times, 25 February 2011.

[96] Tony Moore, *Ratepayers 'not at risk' in Clem 7 traffic miscount*, Brisbane Times, 3 November 2009.

[97] Tony Moore, *Clem 7 traffic estimates predict 50,000 car shortfall*, Brisbane Times, 3 November 2009.

forecasts which led investors into thinking 'that the tunnel would have plenty of traffic'.[98]

A1.4.2 Turnkey contract

A turnkey contract requires that the project is constructed so that it can be sold to any buyer as a completed product. The result of such a contract is that the principal has very little involvement and control over the project, with considerable control in the hands of the contractor. Indeed, the contract is often fixed fee, and so the contractor bears all project risk (in theory).

For this contract to be suitable, the principal's needs must be well defined and details must be unimportant, this being as the contractor has complete control over the aspects of the project (engineering, procurement, and construction). Usually, the contractor subcontracts out the specific tasks to subcontractors.

A1.4.3 Engineering procurement construction (EPC) contract

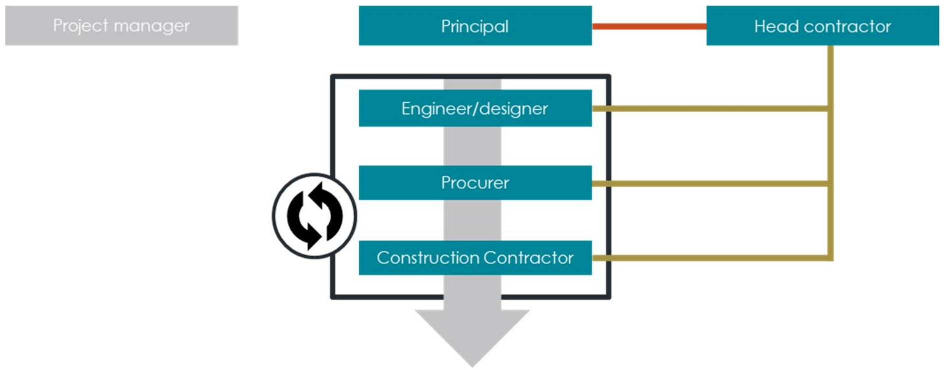
An EPC contract is largely similar to a turnkey contract, presenting a contractor with control over the aspects of the build, ie, engineering, procurement and construction.[99] This presents a single point of responsibility for the principal, and so results in the owner needing only to interact with (and hold responsible) a single party.

Usually EPC contracts include a stipulated completion date that is either fixed, or a fixed period after the commencement of the contract. In the case that the contract is not met, the contractor is liable for delay liquidated damages – eg, as occurred in the case of Samsung C&T's development of Roy Hill mine.

Table A1.3: Advantages and disadvantages of EPC contracts

Advantages	Disadvantages
• Single point of responsibility (and one contract to manage) • Can be more economical as design can consider constructability issues. • Can be time efficient • Reduced complexity	• Difficulties implementing checks and balances as low separation • May be difficult to assess applications due to variation between offerings • Can be expensive due to large premium • Difficult for owner-led variations without penalty • Can lead to disputes between owner and contractor

Figure A1.5: EPC contract structure



[98] Similar claims have been successful against other traffic forecasters, including Arup, which was sued over its traffic predictions for Brisbane's Airport Link tunnel, and Parsons Brinckerhoff and Booz Allen, which were sued over traffic forecasts for Sydney's Lan Cover Tunnel. Jenny Wiggins, *RiverCity IPO investors secure $121m in successful Clem7 class action*, The Sydney Morning herald, 1 June 2016.

[99] The difference being both specificity to the construction sector, and that turnkeys are more inclusive than EPC contracts, ie, a turnkey will include steps from conception to commissioning and startup, whilst the EPC contract may begin with slightly developed design plans and develop from there. EPC contracts are also similar to design and construct contracts, but often involve more risk borne by the contractor and some testing (and possibly commissioning) before the goods are accepted.

A1.4.4 Novated EPC contracts

There is a spectrum of adjustments to the basic turnkey and EPC style contracts presented above. These, in effect, enhance risk mitigation and increase the involvement of the principal.

Under a novated EPC contract, the principal assumes responsibility and control over the design and documentation of the project, either working internally or hiring a contractor which directly reports to it. This leaves procurement and construction to separate contractors.[100] Once design meets an appropriate level, the principal engages a contractor who accepts novation of, and responsibility for the work of, the design consultants.

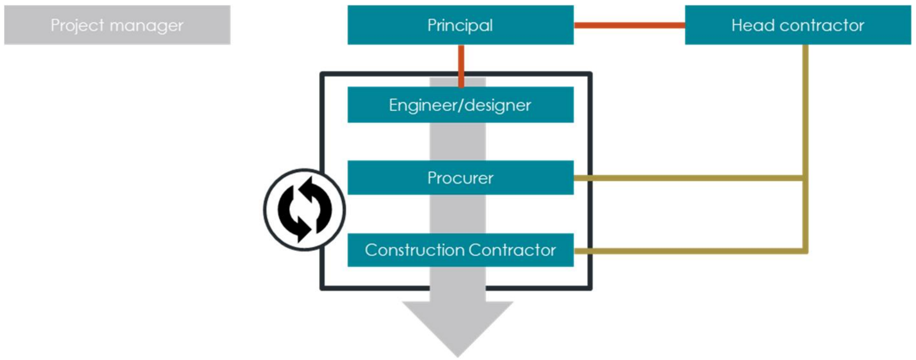
Similar to this, design bid build and construction only contracts separate design and engineering from the procurement and construction stages. This extends the role of the principal to within the design phase, and so increases its control, at the expense of additional risk.

Table A1.4: Advantages and disadvantages of novated EPC contracts

Advantages	Disadvantages
• Close relationship between principal and designer increases principal control • Close relationship between designer and contractor can allow better design that minimises likelihood of constructability issues, and for accuracy checks • Similar benefits to EPC model	• Can be expensive due to possible duplication • Adds complexity due to risk transfer • May lose time effectiveness due to duplication

[100] This is similar to the 'design bid build' method. However, the design bid build method emphasises that the head contractor only contracts procurer/construction contractor and may further require engineers after designs are made.

Figure A1.6: Novated EPC contract structure



A1.4.5 Introducing a project or construction manager

Projects often involve project managers (or construction managers) which provide advice and ownership over ensuring that objectives are met. The difference between the two is that a construction manager is only responsible for the construction and procurement aspects of the project, whilst a project manager is involved to a greater extent. That is not to say that the construction manager is not involved in design or engineering – often advice is sought from the manager to better realise risks. If so desired, the principal can take the role of project manager.

Essentially, a project manager reduces and manages risk, but at a cost, ie:

- reduces likelihood of poor execution – allows criticism of budget, scheduling and scope, and so helps prevent issues such as incomplete design and lack of scope clarity; but
- will take a payment based on the project's success.

A1.4.6 EPC management contracts

Under an EPCM contract, the principal contracts procurers/suppliers, constructors as well as an EPCM contractor which is responsible for carrying out the engineering/design and managing the procurement and construction of the project. At its most basic, the EPCM contract is a consultancy agreement for the provision of numerous services, including:

- basic and detailed design and engineering;
- developing, implementing and managing procurement processes; and
- project management and administration of contracts.

The EPCM can enter directly into contracts with suppliers. However, this is atypical and the EPCM does not often take full responsibility for reaching targets but is incentivised to do so. This captures the potential for variability in EPCM contract roles. An example of an EPCM contract is that used by Telstra and nbn with the nbn II rollout.

Figure A1.7: EPCM contract structure

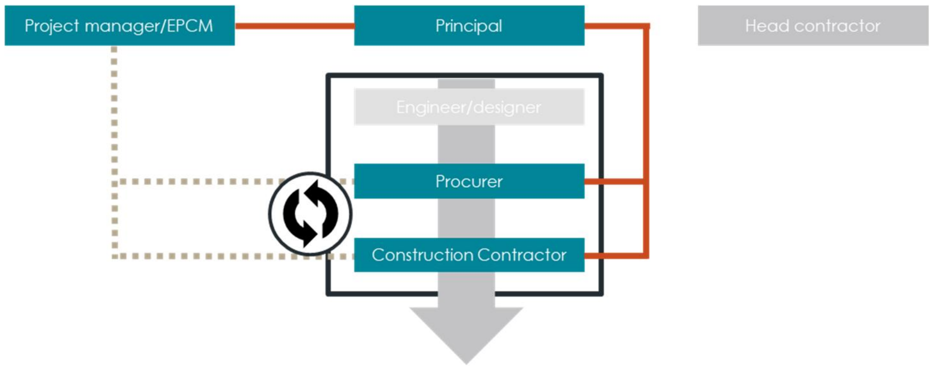


Table A1.5: Advantages and disadvantages of EPCM contracts

Advantages	Disadvantages
• Allows fast tracked construction • Owner retains some control over design • Design can take account of constructability issues by using manager	• No firm project cost established until underway and no warranty of fitness for purpose • Risk that EPCM contractor may prioritise achievement of its goals • EPCM contractor with control over design and construction can lead to conflicts of interest

A1.4.7 Project and construction management (PCM)

Under a PCM contract, the principal engages a contractor (or project manager) to project/contract manage. The purpose of this is to assist the principal in the management aspects of the delivery process. Under this structure, the principal enters directly into contracts with design/engineer contractors, construction contractors and procurers/suppliers.

Figure A1.8: PCM contract structure

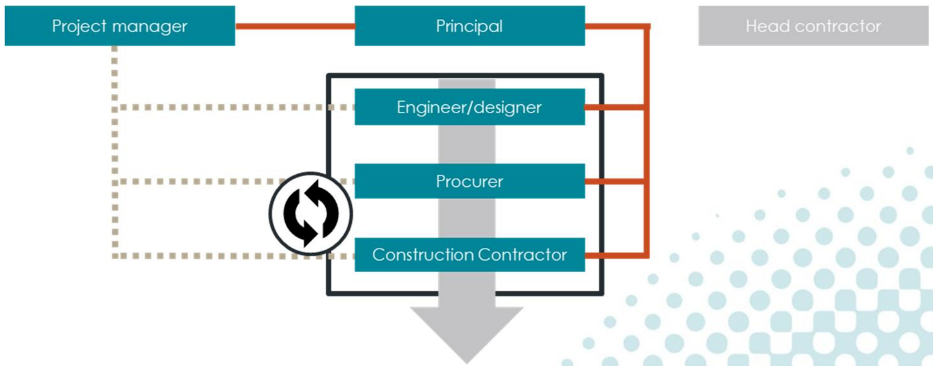


Table A1.6: Advantages and disadvantages of PCM contracts

Advantages	Disadvantages
• The project manager provides useful expertise, and can help control costs and promote collaboration • The system is fast due to the possibility of early works, ie, starting construction before design is finalised • Flexibility is allowed by the principal's direct relationship with contractors • Quality is enhanced • The principal has control throughout the entire project	• Project cost risk lies with the principal • Costs of contract administration and management are high • Many interfaces results in complexity • Managers can face adverse incentives to meet incentives, further requiring well designed contracts

A1.4.8 Other considerations

There are many additional structures and combinations that may be considered, eg:

- **early contractor involvement** – engages contractors early in the process, often before requirements or deigns are finished;
- **front end engineering and design (FED/FEED)** – involves undertaking planning and design early so as to promote ease of contracting;
- **construction manager at risk (CMAR)** – construction manager consults principal during design, but accepts responsibility for construction; and
- **construction management multi-prime (CMMP)** – construction manager consults principal and principal enters contracts with contractors/suppliers.

A1.4.9 Fostering further collaboration

Further forms of contracting are more deliberate in creating collaboration between parties, eg, the principal and all contractors.

Partnering

Partnering is where parties to a construction contract set out guidelines as to how they are to conduct themselves. This aims to promote trust, cooperation and therefore success. The process, which places great emphasis on communication, often starts with a workshop which identifies goals, communication channels and procedures for avoiding disputes – which is codified into a partnering charter that complements the contract and is non-binding.

Alliance contracting

Alliance contacting (often known as integrated project delivery) is an arrangement where parties agree to co-operate and share risk and reward, as measured against performance indicators. This involves the principal and contractors working as an integrated team to jointly achieve their project objectives, which are designed to be consistent with commercial incentives. Underpinning this is a no blame framework, which mitigates the likelihood of costly litigation and disagreements.

Alliance contracting is characterised by the following:

- the remuneration regime is performance based, typically consisting of cost reimbursement of contractors on a 100 per cent open book basis, a fee to cover normal profit and overheads, and gainshare/painshare, which divides gains or losses across project team members;[101]
- project teams are established consisting of team members from across parties (ie, principal, and each non-owner participant)

[101] Success is evaluate relative to clear targets, ie, target outturn costs and minimum project outcomes.

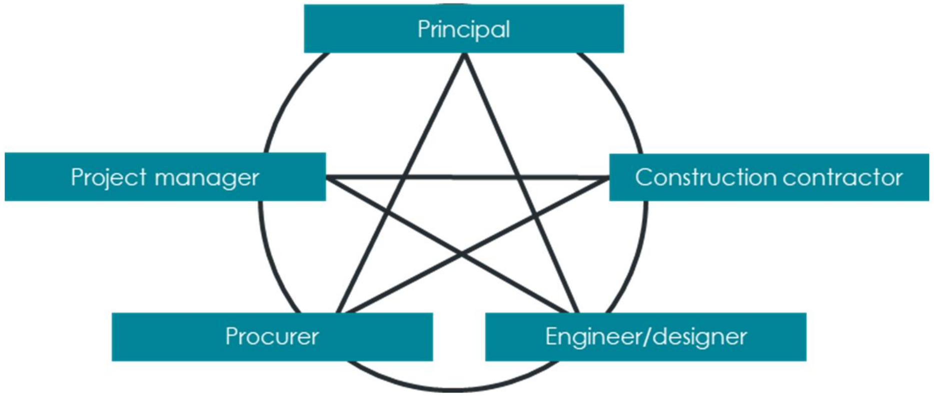
- contractors are continuously involved in the project, from scoping and design to completion;
- decisions are often made unanimously, to ensure support and trust is maintained; and
- the no blame, no disputes clause, under which parties agree to avoid pursuing legal claims (unless, for example, wilful default occurs).

This structure of contract thus places considerable risk upon the owner. However, some remains with contractors, which can lose profit due to cost overruns causing actual outturn cost to exceed targets.

Table A1.7: Advantages and disadvantages of alliance contracts

Advantages	Disadvantages
• All parties have shared responsibilities • Provides flexibility to modify the design • Provides incentives to complete the project on time and on budget • Integrated team eliminates any potential adversarial culture	• Requires a commitment to collaboration • Initial costs can be high, eg, planning and team building • Lack of blame means large ramifications of errors, and difficulties with insurance

Figure A1.9: Alliance structure



Box A1.3: Procurement of Heathrow terminal five

Opened in 2008, Heathrow Terminal 5 is an airport terminal at Heathrow Airport. Whilst construction cost approximately £4.3 billion, took almost 20 years to complete, and involved a public inquiry of approximately four years, the project is considered to have been completed on budget and on schedule.[102]The procurement strategy used by BAA, which informed its approach to procurement, was developed using a 'reference class', ie, a list of similar projects and the difficulties encountered.[103] This list was used to identify risks and get a probability range for outcomes, such as forecast for fatalities, length of development and cost.[104] The procurement strategy

[102] Noting that: (i) the terminal did not open smoothly, which was the consequence of numerous IT problems as well as issues with car parking and (ii) complications regarding the roof of the terminal have led to minor dispute as to whether the budget was indeed met. See: Rogers Stirk Harbour + Partners website, available: https://www.rsh-p.com/projects/heathrow-terminal-5/#, accessed on: 26 June 2020.

[103] A procurement strategy aims to determine the most appropriate contract and payment mechanism, and so enhance the ability to manage the project despite constraints and challenges such as changes in schedule, scale and scope, ie, it aims to minimise cost overrun and time delays whilst achieving quality targets. The reference-class was developed as part of a two year study of large construction projects both in the UK and which related to international airports.

[104] Gerald de Valence, *Procurement case study: Heathrow Terminal 5 2007*, 29 May 2018.

developed by BAA focussed on managing innovation, risk and uncertainty, recognising that a modern approach was required to make the considerable project succeed.

The approach developed by BAA, which has been described as 'unusually collaborative',[105] involved in house project management teams, and collaboration and collocation of its different suppliers. This corresponded to the incentive contract designed by BAA to promote coordination between its many suppliers, ie, the T5 Agreement.[106]

The T5 Agreement was a form of cost-plus incentive contract, whereby, at its most basic, BAA paid suppliers the actual cost that they encountered plus a fixed fee, including overheads and profit. Unlike standard cost-incentive contracts which share risks between the client and contractors, the T5 Agreement meant that BAA assumed all responsibility for the risk. An implication of this was that suppliers could not price risk into their estimates.

To ensure contractors were productive given that they were not bearing risk, an incentive mechanism was developed which provided contractors with lump sum payments for beating targets, ie:[107]

- it granted contractors rewards for beating estimated sub-project specific target costs;[108] and
- it rewarded project teams (rather than specific suppliers) for beating deadlines for deliveries.

The incentive mechanism evolved throughout the project. For example, in 2004 cost targets were made more difficult to reach, which resulted in the accumulation of a £100 million central pot that allowed more effective adaption to risk. Overall, the effect of the incentive mechanism was that the risk of cost overruns borne by BAA was hedged due to contractors striving to maximise their profit through cost savings. However, whilst the incentive mechanism evolved, BAA worked to ensure that the profit margin defined at the onset was maintained, ie, changes that would result in additional work or cost were treated as exceptional and ring fenced profit was adjusted in response.[109]

Excluding the delays within the planning process, construction was considered to have been on schedule, with construction beginning in early 2002 and the terminal opening in March 2008. The implemented approach led to a final cost of £4.3 billion, which was attributed to the construction of the main terminal building and related projects, including a multistorey carpark, an air traffic control tower, a spur road, a 605-bed hotel, the diversion of the Twin Rivers and the extensions to underground rail lines.'[110]

[105] Gerald de Valence, *Procurement case study: Heathrow Terminal 5 2007*, 29 May 2018.

[106] The undertaking required the collaboration of many suppliers including traditionally competitive engineers, architects and design consultants, specialised subcontractors, general contractors, and manufacturers. Indeed, the supplier network had 80 first-tier, 500 second-tier, 5,000 third and 15,000 fourth-tier suppliers, eg, Laing O'Rourke, AMEC and MACE, Richard Rogers Partnership, Pascall+Watson, Arup and Mott McDonald. Rogers Stirk Harbour + Partners website, see: https://www.rsh-p.com/projects/heathrow-terminal-5/#, accessed on: 27 May 2020; Gerald de Valence, *Procurement case study: Heathrow Terminal 5 2007*, 29 May 2018.

[107] Note that, for the below the converse is also true, ie, delays or cost overruns would see a reduction in contractor profit.

[108] These rewards were split three ways between the suppliers and BAA, with one third held as contingency for delivery once the project completed. Furthermore, the split between suppliers/contractors was shared amongst the suppliers on a basis that was negotiated by members. Initially, complaints were made that the incentive payments were too delayed.

[109] Nuno Gil, *BAA – The T5 Project Agreement (A)*, Case study 308-308-1, The University of Manchester, p 7.

[110] Louise Butcher, *Heathrow Airport*, Briefing paper CBP 1136, House of Commons, 20 June 2018, p 10; The Telegraph, *Heathrow's Terminal 5: a great leap forward*, 26 January 2008.

A1.5 Awarding contracts

A further consideration made by principals is the mechanism by which contracts are awarded, ie, the means by which the contract is allocated to the best value contractor, subject to relevant constraints. Within the procurement space, there are a range of approaches which aim to tackle this problem, including:

- negotiated tender, which involves the principal entering negotiations with a single contractor;
- traditional tender, which involves the submission of proposals and analysis by the principal;
- the public private procurement (PPP) process; and
- designed procurement, which involves the application of modern auction theory to design a competitive process.

We discuss these options in further detail below.

A1.5.1 Negotiated tender

Negotiated tender involves the principal selecting and engaging with a single contractor until agreeable terms are reached. As a single contractor is interacted with, the contractor can become increasingly involved in the project, eg, a construction contractor can share its knowledge while the design is still being developed.

Negotiated tender is largely relationship based, and so closely corresponds to the alliancing partnering methods, as well as the early contract involvement (ECI) method whereby a construction contractor is hired prior to design completion and before details of construction requirements are fully developed. The benefits of negotiated tender are thus related to its ability to enable the leveraging of existing relationships, ie, to enable construction contractor involvement in design and so promote time effectiveness, to reduce the need for the development of new relationships, and to reduce administrative burden associated with selection.

However, because of its focus on existing relationships, negotiated tender places little emphasis on promoting competition. Furthermore, it does not overcome issues related to information asymmetry and incentives, ie, it:

- makes little effort to overcome information asymmetry, and so may result in contractors receiving significant premiums in instances where the principal is not knowledgeable;
- may be impacted by imbalances in bargaining power, which arise due to contractors having greater dedicated resources and understanding; and
- does little to overcome possible instances where contractors have sharper incentives than the principal.

Table A1.8: Advantages and disadvantages of negotiated tender

Advantages	Disadvantages
• Time effective • Cost effective where strong relationships exist • Reduced administrative costs associated with simple selection process • Allows the leverage of pre-established relationships and construction contractor involvement in earlier stages	• Reduced usefulness in discrete interactions where relationships cannot be leveraged, or do not exist • Does not promote competition and so may promote inefficient costs • Makes little effort to overcome information asymmetry or incentive problems

A1.5.2 Traditional (competitive) tender

The traditional tender approach involves the presentation of the project to contractors, which then provide cost estimates and possibly design specifications. This involves competition in the sense that the procurer is provided with a range of alternatives which it selects from.

Usually, the traditional approach requires comprehensive documentation so that there is little room for errors and discrepancies. Indeed, to ensure that appropriate selection can be made, documentation needs to be adequately thorough such that it induces substantially similar and comparable proposals. If documentation is unclear, and so responses are varied and ill-suited, it is unlikely that a decision will be clear and timely. This places significant pressure on administrative costs.

However, allowing for competition can lead to a vast array of benefits, namely that the premium required by contractors may reduce. Furthermore, open competitive tender lends itself to the involvement of new and innovative contractors, which in turn can lead to cost efficiencies and expedited project completion. Importantly, to the extent that reputation and past relationships are valued, these can be given weight in tender assessment – although caution would be needed to ensure that this would not be overly strong as to disincentivise entry.

Table A1.9: Advantages and disadvantages of traditional tender

Advantages	Disadvantages
• Paired with a reference price, can result in efficient costs through competition • To the extent that tender is open, can promote a wide array of solutions being submitted, which can lead to innovation and cost efficiencies	• Success may be limited in a thin contractor market • Requires significant administrative effort to ensure that the problem is well defined • Requires significant administrative effort to ensure that an appropriate bidder is selected, and so may be both cost and time intensive • Is likely to be less effective where selection is difficult, eg, when there is large variance in proposals

[111] As common defined in Australia.

A1.5.3 Public private procurement processes

Public private partnerships (PPP) describe arrangements whereby the public and private sector work together to achieve an outcome, and usually involve private sector finance and the bundling of design, construction, maintenance, and other services.[111] PPPs are generally of two types:

- social infrastructure PPPs, which involve the government providing revenue to the private sector directly; or
- economic infrastructure PPPs, which involve the private sector receiving revenue from users, eg, through road tolls or tariffs.

The mechanism used to secure the partnership generally follows a distinct and clear process, ie:

- the government announces the contract, prepares a draft contract, detailing the desired outcome and risk allocations, and calls for proposals;
- consortiums are formed and respond to the request, specifying designs and costs; and
- the government selects the preferred bidder.

As an alternative to traditional contracting (discussed in Appendix 1.4), PPPs *can* deliver superior value for money for government as they can combine better infrastructure solutions and outcomes, with less government risk. Furthermore, in theory, a PPP mitigates issues related to continued negotiation and need for further contracts throughout project development, as it requires necessary contracts to be signed at an early point in the project.

The PPP process itself offers a thorough and clear mechanism by which risks are identified and allocated. Indeed, the devotion of effort from government to assess risks and concerns promotes a reduction in risk based information asymmetry.[112] A further benefit of the process is its focus on outputs (ie,

[112] There is no reason why good practice risk allocation cannot be applied to options in Appendix 1.4.

solutions), rather than a means by which services are provided. This can help avoid solutions which are unnecessary large and inefficient.

While the PPP process is popular in government, some consider it to be too prescriptive, ie, because the process is essentially a recipe for procurement, it can fail to appropriately account for nuances, eg, information asymmetry between government and the private sector, and the incentive structures needed in contracts. Consequently, procurement via PPP may be expensive for the purchaser and involve inefficiently priced risks, eg, demand risk.[113]

Table A1.10: Advantages and disadvantages of the PPP process

Advantages	Disadvantages
• The standardise process results in best PPP practice being readily adopted • Effort to understand risks may reduce information asymmetry • If project is appropriate, can result in substantial benefits from risk sharing and private sector outsource	• Can restrict innovation by placing significant risk on private partner • May be too rigid following of PPP processes leads to failure to recognise incentive issues and concerns relating to information asymmetry

A1.5.4 Designed procurement

Designed procurement presents a modern approach to solving the procurement problem, relying on the application of auction theory to design a competitive process. We understand that this approach appreciates the fact that each project (or group of projects) has nuances, and so a bespoke, tailored solution is required.

Designed procurement involves the dedication of substantial thought as to the practical realities of the market, the incentives present and information asymmetry which may lead to poor outcomes. While this may be associated with increased administrative costs associated with research and development, the prospect of enhanced competition may offset any and all relevant costs. Examples of solutions stemming from designed procurement include:

- the use of closed multi-round or open auctions to increase the intensity of competition; and
- the segmentation of assets, and application of a combinatorial auction to increase the margins of competition.

However, we understand that the adoption of designed procurement has been limited.

Table A1.11: Advantages and disadvantages of designed procurement

Advantages	Disadvantages
• Creative and bespoke solutions may lead to considerable cost efficiencies • Places enhanced emphasis on understanding incentive issues and issues arising from information asymmetry	• May be considered risky as has not been utilised to the same extent as traditional solutions • May incur increased administrative effort, which results from bespoke process

[113] One approach to mitigating demand risk is to use a revenue target.

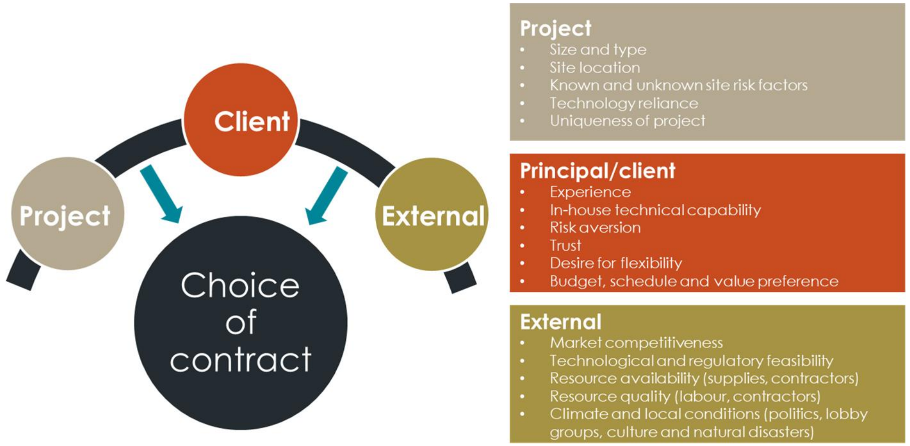
A1.6 Selecting a contract and mechanism

The process used to select a contracting structure is based around multiple key concerns:

- principal characteristics and objectives;
- project characteristics; and
- external environment.

These considerations are depicted in the following figure.

Figure A1.10: Factors influencing choice of contract/procurement



The method by which a procurement processes is selected, and procurement processes themselves, are by no means an exact science,[114] ie, there is no mutually exclusive set of criteria which both uniquely and completely determine an optimal procurement method.[115] Indeed, given that there are many different combinations of procurement structure and pricing methodology, an expert consensus which provides a simple framework for procurement selection has not been reached.[116]

While we recognise that there is no absolute solution to the procurement problem, there are circumstances which promote particular pricing methodologies, contract structure combinations and mechanisms, or, at the very least, lead to unambiguously unsuitable combinations. Our analysis of the circumstances in which contract mechanism combinations are suitable is summarised in the table below.

Table A1.12: Analysis of contract combinations

Characteristic	Suitable pricing and structure	Unsuitable pricing and structure
Large, complex projects lead to design uncertainties and the need for flexibility In large projects, there is often room for progressive changes in design as discoveries are made, eg, in greenfield projects, due to finding unstable grounds along the preferred route, and in brownfield projects, due to the need to assess existing assets to understand the level and nature of work required. If the principal wants to retain control over the reactive design process, it will need to select a contract structure that allows for design control and flexibility. Furthermore, it will need to avoid pricing methods which do not cater for flexibility. This issue is exacerbated by the adversarial nature of contracting.	EPCM contract, PCM contract, and alliance contract. Incentive based pricing with well designed incentives	EPC contract and turnkey contract. Fixed fee.

[114] Alberti (2019) provides a description of the different approaches used by the literature to select procurement methods, eg, priority and weighting based, and case based reasoning. Alberti, J, *An institutional economics approach to megaproject construction contracts*, Inter-American Development Bank, July 2019, pp 6-12.

[115] Love, P, Skitmore, R and Earl, G, *Selecting an appropriate procurement method for a building project*, Construction Management and Economics, 16, 1998, pp.221-223

[116] Love, P, Smith, J, Regan, M, *Procurement Method Selection in Practice: A Journey to Discover the Optimal*, Proceedings W092 - Special track: Procurement systems, CIB publications, 2010, p 52.

Characteristic	Suitable pricing and structure	Unsuitable pricing and structure
Large, complex projects make collaboration and effective management important Large projects necessitate the hiring of multiple contractors and subcontractors, and result in the many parties interacting. Collaboration and a strong culture are one means of promoting effective contractor relationships. Similarly, project managers become increasingly necessary to manage the numerous parties and relationships.	EPCM contract, PCM contract, and alliance contract. Incentive based pricing with well designed incentives	EPC contract and turnkey contract. Fixed fee.
Principals with expertise can get involved A principal that has considerable expertise can be heavily involved in the project, eg, as project manager or within the design phase of the project. With expertise, the principal is well equipped to participate in the project and contribute to its success. This holds for the government also, especially where it is well placed to bear risk.	EPCM contract, PCM contract, construction contract, alliance contract. Incentive based pricing with well designed incentives	EPC contract and turnkey contract. Fixed fee
Inexperienced principals can reduce responsibility A principal with little expertise will be best placed reducing their involvement so as to mitigate risks. This may involve obtaining an advisor such as a project manager to assist, with concern that they may face incentives to mislead.	EPC contract and turnkey contract. Fixed fee	Alliance contract Cost plus incentive
Risk aversion may encourage fixed fees Risk averse principals may prefer contracts which absolve them of as much risk as possible, eg, turnkey and fixed priced contracts. However, the ability of these contracts to absolve the principal of risk is limited given uncertainty and the need for change – which will require change orders or result in litigation. Thorough planning and careful contract development may such issues.	Turnkey and EPC contracts. Fixed price	Alliance contracts.
Insufficient competition may necessitate a cost plus system Limited competition between contractors can lead to inflated bidder margins. To prevent this, a pricing mechanism that utilises a non-fixed price method may be suitable. Furthermore, given the absence of competition, it may be beneficial for the parties to develop long term relationships. A procurement solution that shares risks and encourages trust and cooperation may thus be appropriate. If the principal has sufficient bargaining power, or countervailing market power, then this issue is mitigated. Furthermore, if low quality is a concern a continuity contract may be used, whereby the project is decomposed into smaller elements and the contractor may only continue to the next element if it meets performance requirements.	Alliance contract and partnering. Cost plus incentives.	Turnkey/EPC contract. Fixed fee.
Pre-existing relationships can be powerful Existing relationships between the principal and contractors can lead to efficiencies, eg, through reduced communication barriers and developed trust. Concern must be had for the pricing and incentive structure used as, regardless of relationship quality, incentives can override any preexisting goodwill. The existing relationships of providers may promote the use of negotiated tender. However, this can simply be overcome by a competitive tender which provides weighting to relationships.	Alliance contract and partnering. Cost plus incentives.	Turnkey/EPC contract. Fixed fee.
Innovation can be found in many places Desire for innovation within projects is interesting as innovation may be encouraged by a vast array of contractors. For example, turnkey (fixed priced) contracts may incentivise innovation as a form of cost cutting. However, to the extent that innovation is risky, its use in these situations may be limited. Incentive based systems that encourage collaboration may provide explicit innovation incentives recognising possible gains from innovation. Regardless, involving a wider range of parties will promote innovation – the earlier, the more opportunities. Innovative should not only be encouraged through contracts, but through mechanisms. Designed procurement offers one means by which innovation can be shown by the principal, so as to encourage cost efficiency.	All contracts. Collaboration may be favourable, eg, alliance contracts with cost plus incentive mechanisms	Contracts which reduce contractor involvement are likely less conducive to innovation, eg, construct/build only contracts.
Administrative costs can be difficult to prevent There are many ways in which administrative costs increase when contracting, eg, the need to create competitive tender processes, to develop positive working culture and relationships, and to hire project managers. The leverage of pre-existing relationships and incentive based contracts may overcome this. However, this is only possible to the extent that relationships exist, and may be an unpalatable solution as it is not transparent or competitive.	If relationships exist, negotiated tender	Competitive tender

Highlighted by the above discussion is that, for an appropriate procurement contract to be selected, the principal needs to:

- have a clear idea of the conditions present; and
- understand what it values most, ie, whether there are any indispensable priorities or priorities which can be sacrificed.[117]

One trade off that we consider pivotal to procurement decisions, and so requires explicit reference, is the trade off between risk and control, ie, the more involved the principal becomes, the more risk it is likely to have to bear.

By delegating tasks to contractors, the principal moves from a position of complete project control towards reduced project control, where it can contract out risks associated with project failure. The implication of lost control is that the principal is increasingly subject to the risk that the objectives of the contractor will diverge from its own – an issue which is overcome using incentives. In that sense, the tradeoff faced by a principal designing a contract is between sharing risks and incentives.[118]

Indeed, there is evidence of contractors responding to risks and incentives, and so incentive contracts are often designed to adjust the balance of risks between the contractor and principal, eg, using a defined sharing ratio.[119] Intuitively, the allocation of risks between parties depends on features such as uncertainty, risk aversion, and the contractor's ability to control costs.[120]

A clear takeaway from the above discussion, which is relevant to both mechanism and contract design, is that selection is complex, particularly in the case of large projects. We considered that, as a consequence of the complexities of procurement, devotion of time and thought are necessary for success.

[117] Alberti (2019) summarises different ('criteria') considerations made within the literature, eg, time availability, time certainty, cost certainty, price competition, flexibility, complexity, quality, control/chain of responsibility post briefing, direct responsibility, risk transfer. Alberti, J, *An institutional economics approach to megaproject construction contracts*, Inter-American Development Bank, July 2019, pp 6-12.

[118] Kwawu, W, Laryea, S, *Incentive contracting in construction*, Smith, S.D and Ahiaga-Dagbui, D.D (Eds) Procs 29th Annual ARCOM Conference, September 2013, p 733.

[119] Kwawu, W, Laryea, S, *Incentive contracting in construction*, Smith, S.D and Ahiaga-Dagbui, D.D (Eds) Procs 29th Annual ARCOM Conference, September 2013, p 733; Weitzman M, *The "Ratchet Principle" and Performance Incentives,* Bell Journal of Economics, 11(1), 1980; Stukhart, G, *Contractual incentives*, Journal of Construction Engineering and Management, 11(1), 1984.

[120] Kwawu, W, Laryea, S, *Incentive contracting in construction*, Smith, S.D and Ahiaga-Dagbui, D.D (Eds) Procs 29th Annual ARCOM Conference, September 2013, p 733; Weitzman M, *The "Ratchet Principle" and Performance Incentives,* Bell Journal of Economics, 11(1), 1980; Stukhart, G, *Contractual incentives*, Journal of Construction Engineering and Management, 11(1), 1984.

A2. Delivering transmission investments in the US

Generally, transmission investment in the United States remains a heavily regulated activity, underpinned by state-level or regional planning with transmission tariffs set to enable the recovery of costs incurred, including an approved return *on* investment and return *of* investment. However, competition has been utilised across many jurisdictions, to varying extents, and its prevalence as a means of promoting efficient costs is increasing.

Within this appendix we describe how efficient transmission investments are promoted across the United States, with particular focus on the means utilised by PJM, CAISO and ERCOT.

A2.1 Increasing use of competition to promote efficient costs in the United States

In the United States, high voltage transmission facilities have historically been owned and operated by incumbent monopolist utilities, which are subject to state and federal certification, siting, and cost of service regulation. Both federal and state regulation of the TNSP as a natural monopoly has continued through numerous transformations, including vertical and horizontal restructuring, the creation of competitive wholesale electricity market, and the formation of Independent System Operators (ISO) or Regional Transmission Organisations (RTO) to operate these competitive wholesale markets and the relevant transmission networks.

ISOs do not perform the role of the economic regulator, ie, they are not responsible for the determination of rules for the compensation of transmission owners or the tariffs that specify the level of payment required from users. Where it has jurisdiction, this role, and the role of regulating ISOs, belongs to the Federal Energy Regulatory Commission (FERC), which is an independent federal agency that regulates the interstate transmission of electricity, natural gas, and oil in the United States.

Despite this, states retain some authority, such as to review the siting of proposed transmission projects, eg, environmental impacts and the identified need for investment. Indeed, state certification is required in order for major transmission projects to proceed.

FERC's regulatory processes provide transmission owners with compensation through cost of service procedures. Furthermore, FERC forms a revenue requirement for transmission owners that are within an ISO. The revenue requirement is determined as follows:

- a rate base is determined, which is equal to the depreciated original cost of the transmission owner's facilities;
- the portion of the rate base related to capital cost is the annual depreciation on the rate base plus carrying charges on the rate base, where carrying charges are derived by the specification of an allowed rate of return which is multiplied by the rate base;
- the capital cost elements are then added to each transmission owner's operating and maintenance costs, fees, and adjustments for taxes; and
- in instances where there are multiple transmission owners within the region and shared regional cost responsibility, portions of the revenue requirement are allocated to or from other transmission owners.

As per its role as economic regulator, in principle FERC applies prudent investment and reasonable cost standards to presented capital and operating costs, with the ability to disallow imprudent or unreasonable expenditure. However, in reality these exclusions are rare. Indeed, aside from abandonment incentives, little incentives have been implemented to encourage cost efficiency, and so:[121]

> for all intents and purposes the FERC regulatory process is a model of cost pass-through regulation with little scrutiny of costs.

Despite this, there are some efforts to encourage efficient costs through competition. Indeed, while elements of competition have always existed within the transmission investment space, FERC Order 1000, which was introduced in 2011 and is summarised in Box A2.1, has provided significant impetus for its promotion.

Box A2.1: FERC Order 1000

By 2011, FERC identified that insufficient competition in the nationwide power sector was prompting great inefficiency and so, in July 2011, issued FERC Order 1000. Effective on 11 October 2011, FERC Order 1000 required those under FERC jurisdiction to promote competition for the solution (sponsorship model) or for ownership and development of transmission assets (competitive bid model).

FERC Commissioner John R. Norris summarised the Order as follows:

> Order No. 1000 seeks to provide consumers and our economy with more efficiently priced and delivered electricity by introducing greater competition in the provision of transmission services.

FERC Order 1000 focused on three areas of reform for utilities: planning process reform, cost allocation reform, and nonincumbent developer reform.

1. *Planning process reform*: Planning process requirements include mandatory regional and inter-regional transmission cooperation among TOs. This multi-state or multi-RTO planning process also incorporates a top-down approach that must consider federal and state public policy mandates.
2. *Cost allocation reform*: This focuses on ensuring transmission project costs are distributed appropriately between those who benefit from the project. FERC has identified regional cost allocation principles that each project must meet.
3. *Nonincumbent developer reform*: This involves removing the right of first refusal from TOs. Whereas previously a TO had a right of first refusal to build, own and operate transmission projects in their service territories, this provision, though still in existence in some states, is now opening transmission projects to competition.

The third area of Order 1000 is of particular interest, and the two general models for nonincumbent developer reform emerged from this, ie, the sponsorship model (Level 1) and the competitive bid model (Level 2).

The Order did not set out the details for these two models, except in general terms and to require that both incumbent TOs and nonincumbent TOs must be able to submit competitive proposals. Rather, regions across the country responded to Order 1000 with their own proposals.[122,123] Each Model has its own perceived advantages and challenges, ie:

[121] Joskow, PL, *Competition for electric transmission projects in the US: FERC Order 1000*, MIT CEEPR. March 2019, p 13.

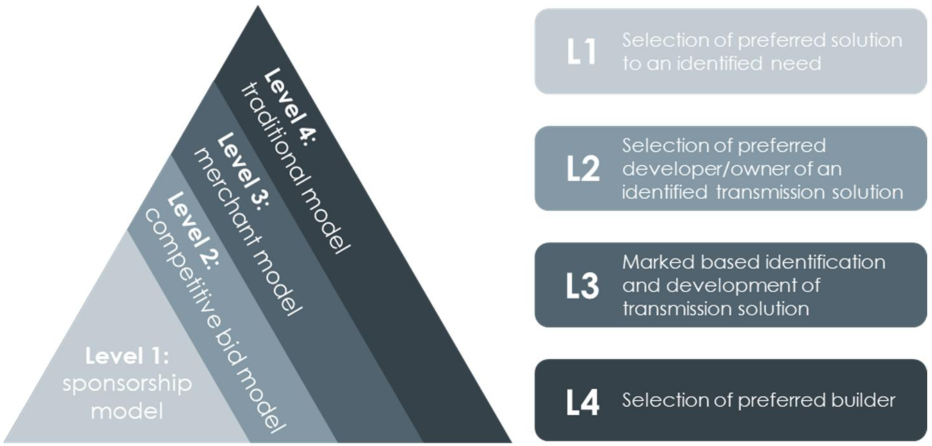
[122] The United States consists of regions with RTOs as well as regions where there are not RTOs performing the transmission coordination function. Further, there are some regions within the United States that do not fall under FERC jurisdiction at all, such as ERCOT. Planning is more regional in nature in the integrated regions where an organised market and numerous state policies exist, such as PJM. In short, there is no common set of rules in the US, despite the fact there is a single national regulator (FERC).

[123] By way of background, US transmission investments are currently amount to about US$20 billion per year in FERC jurisdictional areas, up from about US$2 billion per year in the 1990s. It has been a widely-held view that the US had been under-investing in transmission for many years and change was urgently required. There is a significant desire in the United States to build on FERC Order 1000 and bring more competition into the transmission sector.

- proponents of the sponsorship model, including PJM, argued that allowing competitive tension during the planning phase would allow for the possibility of more innovative solutions and greater efficiency to be delivered. This model was developed to drive a lower cost approach by allowing stakeholders to develop solutions. Indeed, actual results to date from this model have shown at times that the solutions found by the market can be quite different and lower cost than what the central planners might have assumed.
- proponents of the competitive bid model argued that this model is a more practical and more predictable form of increased competition. Indeed, regions using this model have now awarded more projects and many have argued that the process is clearer, more transparent, and easier to manage and control than the sponsorship model.

Encouraged by FERC Order 1000, at present, competition in the transmission sector can exist at various levels, which are highlighted in Figure A2.1.

Figure A2.1: Levels of competition



These levels can be described as follows:

1. **sponsorship model** – involves selecting the preferred transmission solution to an administratively identified need from multiple developer/owner proposals:
   > a centralised planner (RTO) identifies a generalised need and invites competitive proposals/solutions; and
   > developer/owners compete to provide innovative solutions to meet that need;
2. **competitive bid model** – involves selecting the preferred developer/owner of a specific administratively-identified transmission solution:
   > a central planner (RTO) identifies the need and the specific solution/project required; and
   > developer/owners compete to provide the specified project;
3. **merchant model** – involves market-based identification and development/ ownership of transmission solutions:
   > no role for central planner;
   > responding to energy market price signals, merchant investors develop assets in exchange for financial transmission rights (FTRs) or physical transmission rights (PTRs); and
4. **traditional model –** involves selecting the preferred *builder* of a chosen transmission solution, whether the solution was identified by any of the three processes above, or alternatively by an administrative process in which the identity of the transmission owner was predetermined.

In the United States there is a long history of competition at Level 4 (the traditional model), with regards to competition to build transmission projects that were identified as part of an administrative planning process and where it was predetermined that the owner would be the proximate transmission operator (TO). For example, the model has been common practice for PJM in the instance whereby specific transmission solutions are identified. Here, proximate TOs are allocated build/own/operate responsibility, and then put the building process out to competitive tender (typically under an EPC contract). The TO's costs, including those resulting from the competitive tender, are then placed in its rate base, and the TO proceeds to own and operate the facilities under the direction of the RTO.

While competition at Level 3 has historically been stunted, in PJM since 1998 and in some other parts of the United States more recently, the introduction of locational marginal pricing (LMP) and associated financial transmission rights (FTRs) have prompted increased merchant opportunities. This is as:

- LMP provides price signals by which competitive market participants can identify opportunities for efficient "merchant" development and ownership of transmission solutions; and
- FTRs provide the property right such that an owner of merchant transmission can be rewarded for the value created.

With that said, in practise difficulties have emerged which have hindered the adoption of the merchant model, at least in the classical sense.[124] Indeed, while FTRs were once thought to hold great promise for facilitating widespread and efficient merchant transmission investment,[125] the following 20 years have revealed that, whilst they are a helpful instrument for risk management, and LMP by itself has many advantages over its alternatives, FTRs deliver little incentive for transmission investment in practice.[126]

While merchant development remains limited, involvement has been encouraged through physical transmission rights (PTR), which allow developers to take advantage of sustained price differences between adjacent regional zones that have fallen through the transmission planning cracks. Generally, these projects are DC lines because DC lines are more easily controllable than AC lines.

Another form of PTR merchant transmission investment that has taken place, eg, in PJM, has been the equivalent of merchant REZ zones. Merchant transmission developers in Western PJM have financed new transmission lines into untapped wind resource areas in the US Midwest and offered prospective wind farm developers access to their privately financed and planned lines at a price. The wind developers then gain access to sell the energy they produce at the PJM market price of energy at the connection point of the line to the PJM network. While this has been a promising development, it is nevertheless still a very small proportion of total transmission investment.

Level 2, which is analogous to the competitive bid system used in Victoria, ie, seeking competitive tender to a pre-identified transmission solution, has seen use across a wide array of contexts in the US. For example, prior to the introduction of FERC Order 1000, ERCOT utilised a competitive bid system to enable the development of its competitive renewable energy zones.

Competition at Level 1 has been recently explored by PJM and in New York, and has the potential to lead to innovative solutions which may prevent the need for costly transmission expenditure. In the case of PJM, while this option has enhanced competition in the transmission sector, it is fair to say that it has not been the resounding success that was once hoped.

While FERC Order 1000 does promote competition, its effectiveness has been limited. Indeed, in the seven years since FERC Order 1000 was introduced, relatively few transmission projects have been competitively awarded in the wider United States. There are numerous reasons for this, including that stakeholders are still adjusting to operating under the new

[124] Joskow, PL, *Competition for electric transmission projects in the US: FERC Order 1000*, MIT CEEPR. March 2019.

[125] That is, when the FTR concept was initially developed in theory in the 1990s and implemented in practice in PJM and New York in 1999.

[126] There are a number of reasons for this being the case. These reasons have been well-documented and range from issues associated with economies of scale to issues associated with price caps and other factors. In any event, there have been only a few merchant transmission investments driven by FTRs.

regime that FERC Order 1000 has brought. A further description of the success of FERC Order 1000 is provided in Box A2.1.

The key problem in the United States is that the jurisdictional map of regulators and law makers is literally *swiss cheese*. At the national level, the ability of FERC to drive policy is substantially limited as a result. These limitations are highlighted in Texas, where effort has been made to make the network independent, and so FERC has very little regulatory involvement.

Box A2.2: The success of FERC Order 1000

Numerous reports have recently been commissioned on the subject of the success (or otherwise) of FERC Order 1000. They are perhaps best summarised by the House Energy Subcommittee which held a hearing on the state of transmission infrastructure and transmission planning in May 2018 and concluded that Order 1000 has not yet incentivise transmission development as intended and refinements are needed. Former FERC Commissioner Tony Clark summarise his views as:[127]

> Given the changes in the electricity industry over the last decades, now is a good time for the Commission to consider an Order. 1000 reassessment.

He went on to specify one major pitfall of the rule, ie:

> …[that] it imposes bureaucratic planning requirements on the national transmission system, largely without considering that each region's needs, priorities and processes are different.

Nevertheless, a key finding has been that roughly half of the approximately $70 billion of aggregate FERC-jurisdictional investments over the past five years were made based on local planning processes of incumbent TOs with limited RTO review and stakeholder input. Consequentially, less scrutiny was used in assessing the needs and cost-effectiveness of the investments than envisaged. For example, in PJM between 2013 and 2017, approximately US$31 billion of transmission investment was added to the consumer rate base, and of that less than half was subject to the full stakeholder engagement process in the regional transmission expansion plan, ie, investments based on local planning processes of incumbent TOs (supplemental projects) were only subject to limited review.

There does not appear to be a strong industry-wide consensus to revoke FERC Order 1000. Rather, there is general agreement that the three key elements of reform are required, but the means to implement them needs to be further refined.

Former FERC chairman, James J. Hoecker, made this point and others when testifying to the House Subcommittee. ie, that:[128]

- continued under-investment is not an option;
- an integrated, regional and multistate network under laws and a jurisdictional division of labour is being built based on a completely outdated business model of local and state monopoly; and
- Order 1000 instituted the regionalisation of grid planning and allocation of costs to true beneficiaries that are, and should remain, the touchstones of grid regulation. It has generated many successes, and now we should move beyond it.

A2.2 Planning and delivering large transmission investments in PJM

PJM is a FERC-jurisdictional multi-state Regional Transmission Organisation (RTO). It has approximately 1,040 members, who in turn have approximately 186 GW of generating capacity, 360,000 miles of transmission lines, and serve approximately 65 million people in 13 states and the District of

[127] Rawley, J, *Assessing the effectiveness of FERC Order 1000*, Burns & McDonnell, 2019, p 10.

[128] Rawley, J, *Assessing the effectiveness of FERC Order 1000*, Burns & McDonnell, 2019, p 10.

Columbia. PJM's Transmission Owner (TO) members are subject to economic regulation from both the state Public Utility Commission (PUC) regulators and the federal regulator (FERC).

PJM's methodologies for planning and delivering transmission infrastructure are generally considered to be among best practices in the United States, but the factor that makes PJM a particularly interesting case study is its evolving boundary between the use of administrative mechanisms to promote desired transmission outcomes, and its use of competitive mechanisms to promote these outcomes.

A2.2.1 Regional transmission expansion planning

Planning the enhancement and expansion of transmission capability on a regional basis is one of the main purposes of RTOs like PJM. PJM implements this function through its regional transmission expansion planning (RTEP) process, which aims to ensure the transmission system continues to deliver power reliably and economically into the future. The process, which is region-wide, is designed to provide the opportunity for economies of scale, which promote more efficient transmission planning and construction.

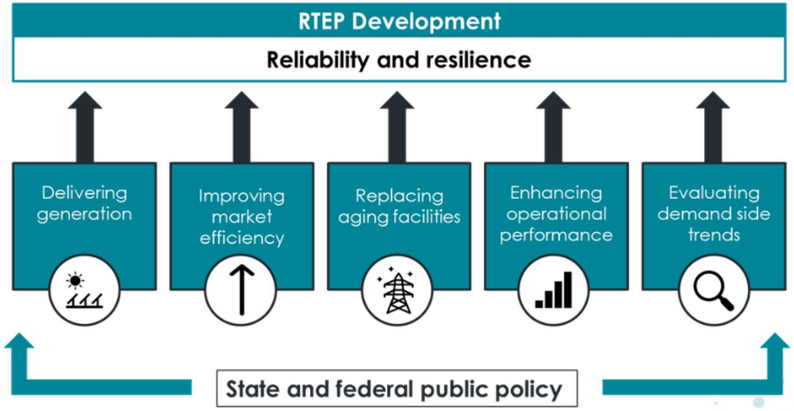
RTEP identifies transmission system upgrades and enhancements to provide for the operational, economic and reliability requirements of PJM customers.[129] Furthermore, a 15 year planning horizon is applied to ensure that transmission constraints, reliability concerns, and the long term effects of numerous drivers are appropriately considered. The drivers considered, which are viewed through the perspective of system reliability and resilience, have evolved since the RTEPs inception in 1997, whereby PJM mainly consider load growth and generation resource interconnection requests. Indeed, as illustrated in Figure A2.2, in additional to these considerations, PJM's RTEP process currently studies the interaction of drivers including those arising out of public policy, market efficiency, aging infrastructure, operations performance and demand-side trends.[130]

Following the identification of possible reliability criteria violations, transmission upgrades are identified and examined for feasibility, impact and costs. The RTEP process thus has two main steps:

1. identifying project needs; and
2. developing transmission solutions.

These steps, which are expanded upon below, are not unusual for RTOs or their global equivalents. However, PJM is a particularly interesting case study as it has driven the introduction of competition in the identifying project needs.

Figure A2.2: RTEP development



Source: PJM

[129] It also integrates transmission with generation and load response projects.

[130] In practice, the dynamics driving transmission expansion have been shifting rapidly in PJM. New large-scale transmission projects (345 kV and above) have become rarer as load growth has fallen below 0.5 percent. Three main factors are driving new system enhancements: aging infrastructure, grid resilience and the shift in generation resources (towards renewables)..

Project needs are first identified

This step involves PJM identifying future transmission needs. As part of this process, PJM assesses what is required to ensure that the transmission system continues to comply with national and regional reliability criteria to prevent overloaded facilities and potential blackouts. Several interrelated drivers go into identifying transmission needs. Criteria include those set out in PJM planning procedures, North American Electric Reliability Corporation (NERC) Reliability Standards, regional entity reliability principles and standards, and individual transmission owner local planning criteria. The standards include thermal, reactive, stability and short-circuit standards.

The RTEP process is highly structured, and very much centred on its stakeholders. A Transmission Expansion Advisory Committee (TEAC) provides the main stakeholder forum for the ongoing exchange of ideas, discussion of issues and presentation of RTEP upgrades. PJM's Regional Planning Process Working Group (RPPWG) addresses specific issues associated with 15-year planning, market efficiency and interconnection request processes. Three sub regional RTEP committees (SRRTEP) provide a forum to review sub-regional RTEP upgrades and to provide input and recommendations to the TEAC. Ultimately the TEAC recommendations, including the baseline project recommendations, are formally submitted in the form of a PJM Staff White Paper for PJM Board approval.

The final RTEP plan contains three types of transmission requirements:

1. *Baseline needs* – which are investments needed to ensure compliance with national and regional reliability standards, including PJM transmission planning criteria, TO criteria, and market efficiency criteria. These projects are identified to fix issues like overloads, bus voltage drops, excessive short circuit current, generator stability and congestion issues. Importantly, baseline projects include projects that have been identified for market efficiency reasons (for example, lowering overall PJM generator dispatch cost).[131]
2. *Network projects* – which are identified to help new generation resources connect to the grid reliably.
3. *Supplemental projects (transmission replacement projects)* – which are expansion or enhancement projects identified and developed by TOs to address local needs, including customer load growth, equipment replacement needs, cyber security, safety and environmental requirements, operational performance and risk, and infrastructure resilience. They are not required for compliance with PJM reliability, operational performance, or economic efficiency criteria. PJM reviews them to evaluate their impact on the regional transmission system.

Competition is implemented in the development of transmission solutions

The means by which competition is enabled depends on the relevant transmission requirement.

Baseline needs

The Sponsorship Model is applicable to baseline needs. Baseline needs are largely expressed in terms of what solution is required, rather than how the solution is delivered with a particular technical or engineering requirement. After PJM identifies a baseline transmission need, PJM may then open a competitive proposal window, depending on the required in-service date, voltage level and scope of likely projects.

PJM announces its intention to solicit competitive solutions to identified planning needs in rolling 'windows'. There are three such windows, which are highlighted in Table A2.1 below.

[131] In practice an important component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission enhancement plans to resolve reliability criteria violations identified under prescribed deliverability tests.

Table A2.1: Planning cycles

Planning Cycles	Standard Window Length	Required In-Service Date
Long-Term: considers reliability criteria violations, economic constraints, system conditions and public policy requirements. This is relevant to projects with required in-service dates greater than five years away that address identified reliability criteria violations, economic constraints or reliability pricing model (RPM) limits, operational performance and public policy requirements.	120 days	> 5yrs
Short-Term: considers reliability criteria violations. This is relevant for projects which address reliability driven upgrades with required in-service dates between three and five years out.	60 days	3-5yrs
Immediate-Need Reliability: considers reliability criteria violations. If PJM determines that insufficient time remains for a proposal window to be implemented, PJM may post reliability violations that could be addressed by a project required to be in service within three years or less. If PJM determines that there is sufficient time for a proposal window for immediate-need reliability project proposals, PJM will open a shortened proposal window.	Shortened	< 3yrs

Source: PJM Manual 14F

Throughout each RTEP window, developers can submit project proposals to address one or more need. When a window closes, PJM evaluates each proposal to determine those that meet all the stated requirements. Assuming that minimum competitive requirements are met, PJM then evaluates the proposals and recommends the preferred proposal to the PJM Board. Once the Board approves a proposal, the designated developer becomes responsible for project construction, ownership, operation, maintenance and financing.

The process provides non-incumbent transmission developers (and incumbents) an opportunity to participate in the regional planning and expansion of the PJM bulk electric system. By publishing a set of criteria violations and soliciting solutions from competing transmission developers, PJM aims to encourage innovative, cost effective and timely solutions to the challenges of building and maintaining a highly reliable electric system.

Network projects

PJM identifies the affected parties who bear the responsibility for network system projects that permit the interconnection of new generation and other new transmission services. The sponsorship model does not apply to these projects.

Supplemental projects

Historically, TOs have developed supplemental projects themselves to address local reliability needs and were responsible for building them. Prior to 2020, supplemental projects required no approval from the PJM and were only subject to a “no harm” analysis by PJM. However, in January 2020 FERC approved a change to the PJM tariff that eliminates the exemption from the competitive proposal window process. FERC required this change to recognise that costs of these RTEP projects are no longer allocated to the zone where they are located but are allocated via a distribution factor and load ratio share.

A2.2.2 Competition is increasingly used to augment administrative means of revealing efficient costs

PJM’s default regime relies on an administrative means for revealing efficient costs. For example, costs of legacy transmission (which is most transmission) are generally regulated on a cost-plus basis with periodic rate cases to reset tariffs as required.[132] A complex system of fixed and formula rates (and mixed fixed and formula) has evolved over the years. Furthermore, there can be gaps of many years between rate cases, eg, if a TO can reduce its costs then it might wish to delay its net rate case, and vice versa if costs increase.

As competition increasingly moves into the transmission sector in PJM, the means for revealing efficient costs is evolving. First, where competition is at Level 4 (traditional model), FERC and the PUCs are increasingly concerned that procurement tender processes run by TOs are efficient and competitive. This involves regulations regarding transparency, codes of conduct for any TO affiliates participating in the tender, minimum competitive metrics, clearly-defined project specifications, and so on. For competition at Level 1 (sponsorship model), FERC is concerned that PJM itself runs an efficient process; albeit many of the requirements that apply to PJM might not be the same as those that apply to a TO. For example, as the sponsorship model does not necessarily include clearly defined project specifications; the evaluation methodology is much more complex as it must allow for non-price factors to be considered and for a bidder-specified risk allocation. On the other hand, the sponsor model does not lead to bidding concerns and so there is no need for codes of conduct.

In either case the goal is to ensure that, where tender bid prices ultimately enter the TO rate base, the cost revealed by the tender process reflects full and efficient competition. It is not a requirement to reflect actual costs, but this may be considered to the extent that it is deemed efficient to do so on a risk-adjusted basis.

The importance of appropriate selection of proposals has led to innovation in how proposals are evaluated. For example, recent developments at PJM have included the introduction of greater flexibility in how PJM evaluates costs within the competitive planning process, ie, project proposals can include binding cost commitments, non-binding cost estimates, or a mix.

A2.3 Delivering transmission investments in CAISO

Transmission planning in the majority of California is undertaken by the California Independent System Operator (CAISO), which is an independent system operator responsible for providing open and non-discriminatory access to the majority of California's wholesale transmission grid. Indeed, in addition to the large footprint that CAISO is responsible for, as highlighted in Figure A2.3, it manages the flow of electricity for about 80 per cent of California and a small part of Nevada.

As California is interconnected with and imports substantial electricity from neighbouring states, CAISO is FERC regulated. Furthermore, CAISO must interact with the California Public Utilities Commission (CPUC), which regulates investor-owned utilities and their network assets.

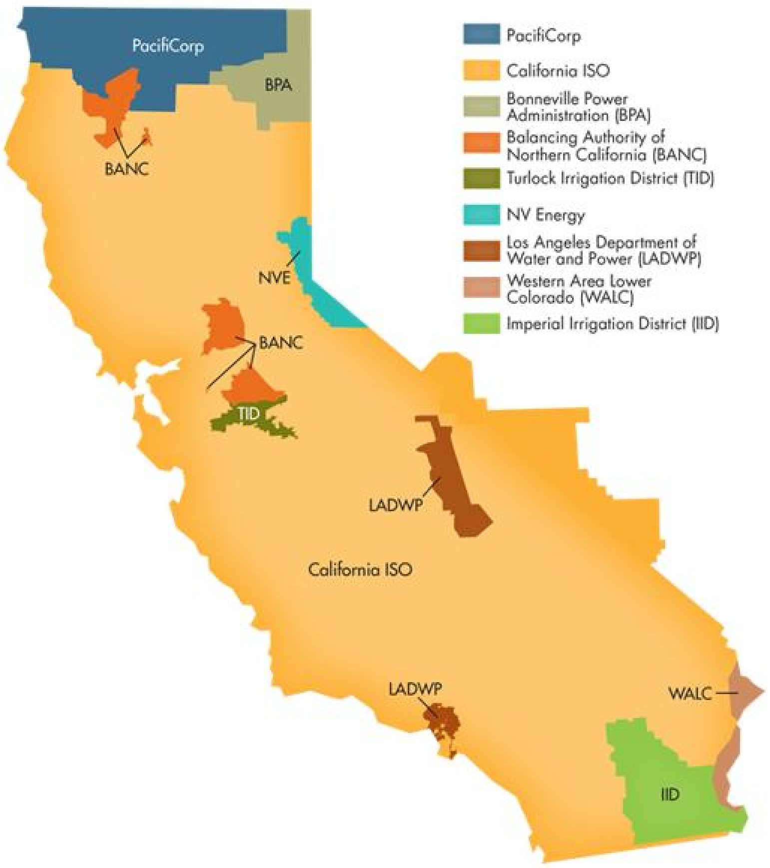
A2.3.1 The transmission planning process

Each year, CAISO conducts its transmission planning process to identify potential system limitations as well as opportunities for system reinforcements that improve reliability and efficiency. This process culminates in a CAISO Board of Governors (Board) approved transmission plan that identifies:

- necessary transmission solutions and authorises cost recovery through CAISO transmission tariff rates (subject to FERC regulatory approval); and
- non-transmission solutions that can be pursued as an alternative to transmission investment (although these alternatives fall outside of CAISO's direct control).

[132] Transmission charges in PJM primarily apply to consumers on the basis of the incumbent TO service territory in which the consumption occurs. Each incumbent TO has a tariff sheet that applies transmission charges with electricity consumed within its zone. Allocations are calculated using a distribution factor methodology that allocates the cost to the load zones that contribute to the loading on the new facility and/or on a load-ratio basis. Projects exclusively benefitting a local TO are allocated to the local TO zone concerned. Market efficiency projects are allocated to the load zones that benefit from the upgrade.

Figure A2.3: CAISO grid and neighbouring balancing areas



Source: CAISO

The planning process encourages stakeholder involvement

The transmission plan, which is developed through stakeholder consultation, relies on inputs from the CPUC and the California Energy Commission (CEC), including:

- long term forecasts of energy demand produced by the CEC as part of its biennial integrated energy policy report;
- biennial integrated resource planning (IRP) proceedings conducted by the CPUC; and
- annual transmission planning processes performed by CAISO.

With appropriate inputs obtained, the transmission plan proceeds to identify three main categories of solution: reliability; public policy and economic needs. In addition, it may also:

- include transmission solutions needed to maintain the feasibility of long-term congestion revenue rights;
- provide a funding mechanism for location-constrained generation projects; or
- provide for merchant transmission projects.

CAISO also considers and places an emphasis on the development of non-transmission alternatives, both conventional generation and preferred resources.[133] Though CAISO cannot approve non-transmission alternatives as projects, these can be identified as the preferred mitigation in the same manner that operational solutions are often selected in lieu of transmission upgrades. Further, demand side response assumptions are also incorporated into the load forecasts adopted through state energy agency (CPUC and

133 Preferred resources refers to energy efficiency, demand response, renewable generating resources and energy storage programs.

CEC) activities that CAISO supports, and provide an additional opportunity for preferred resources to address transmission needs.

The planning process consists of three phases

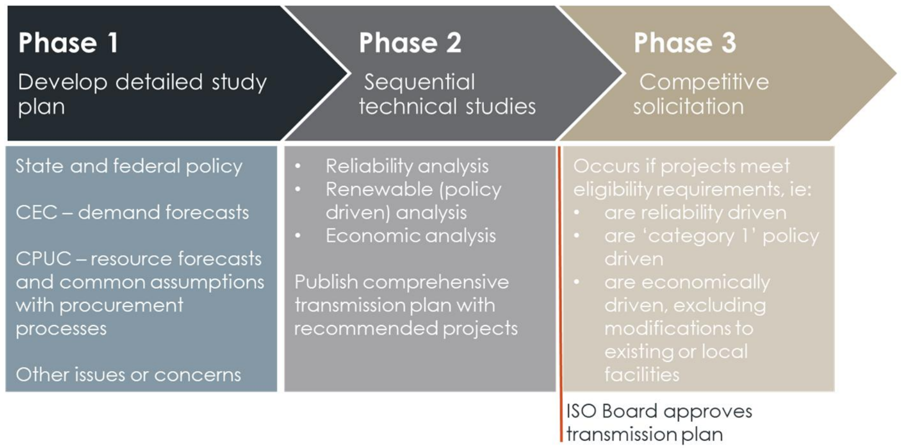
The transmission planning process is defined by three distinct phases of activity that are completed in consecutive order, ie:

- **phase one (develop study plan)** – in collaboration with stakeholders, CAISO establishes assumptions and models for use in planning studies, develops and finalises a study plan, and specifies the public policy mandates that planners will adopt as objectives in the current cycle;
- **phase two (conduct technical studies and develop comprehensive plan)** – CAISO performs technical studies and develops an annual comprehensive transmission plan that examines the CAISO controlled grid, as well as reliability requirements, and identifies mitigation solutions which may meet reliability, economic or public policy-driven needs that support state, federal, municipal and county policy requirements and directives;[134] and
- **phase three (competitive solicitation, if appropriate)** – CAISO solicits solutions from prospective developers to build and own transmission facilities identified in the Board approved plan.

Phase two, is of particular interest as it involves the identification of options to meet a range of transmission needs, ie:

- policy driven transmission facilities to integrate renewable generation, consisting of two forms:
  - > category one transmission elements, which are relatively urgent, and determined using a least regrets analysis which balances the need to minimise risk of underutilisation with timely development; and
  - > category two transmission elements, which may be needed to achieve policy requirements but are contingent on future developments;
- facility enhancements or modifications to promote achievement of planning needs; and
- non-transmission alternatives that are being relied upon in lieu of transmission solutions also takes place at this time.

Figure A2. 4: CAISO grid and neighbouring balancing areas



Furthermore, phase two involves CAISO undertaking economic studies (which are summarised in Box A2.3) to determine which of the identified reliability and policy driven solutions should be included in the final comprehensive transmission plan. The Board's approval of the authorises implementation of the reliability-driven facilities, category 1 policy-driven facilities and the

[134] The identification of non-transmission alternatives that are being relied upon in lieu of transmission solutions also takes place at this time.

economically driven facilities.[135] Additionally, it enables cost recovery through CAISO transmission rates (subject to FERC approval).

Box A2.3: CAISO's economic assessment

CAISO has developed a transmission economic assessment methodology (TEAM) to undertake an economic evaluation of transmission upgrades (to comply with processes and standards defined in its FERC tariff). While this methodology has been used by CAISO since 2004 it continues to evolve to reflect changes in the underlying market, the impact of renewables integration, and to take advantage of improved study tools and models.

Five key aspect underpin the evaluation:

- benefit framework;
- network representation;
- market prices;
- uncertainty; and
- alternatives.

These aspects do not need to be applied in exacting detail for each study. Rather, the type of study and initial study results dictate at what level each are applied.

CAISO relies on a ratepayer (customer) perspective when evaluating the economic viability of a potential transmission upgrade since the cost of transmission upgrades is collected from ratepayers through the transmission access charge (TAC). Additionally, a societal perspective is applied as a test for the benefit of the whole Western Electricity Coordinating Council (WECC) region, especially when upgrades have interregional impacts.

A2.3.2 The competitive solicitation process provides a competitive means for revealing efficient cost

Phase three of the planning process provides for competition in instances where there are eligible reliability-driven, policy-driven, and economic-driven projects deemed necessary in the final comprehensive transmission plan.[136] However, while the latest transmission plan (2019-2020) identified nine transmission projects with an estimated cost of $141.7 million to maintain transmission system reliability, no transmission projects included facilities eligible for competitive solicitation.

Where transmission projects that are compatible with the competitive solicitation process are identified, a process which seeks to select an appropriate project sponsor to finance, own, and construct the transmission facilities commences.

To determine the key criteria for each relevant transmission solution, CAISO considers:[137].

- the nature, scope and urgency of the need for the transmission solution;
- expected severity of siting or permitting challenges;
- the size of the transmission solution, potential financial risk associated with the transmission solution, expected capital cost magnitude, cost overrun likelihood and the ability of the Project Sponsor to contain costs;

[135] Under existing tariff provisions, CAISO management can approve transmission projects with capital costs equal to or less than $50 million. Such projects are included in the transmission plan as pre-approved by CAISO management and not requiring further Board approval.

[136] CAISO, *California Independent System Operator Corporation Fifth Replacement FERC Electric Tariff*, 12 August 2019

[137] Proposals are also required to fulfill information requirements, ie, so as to provide adequate information to allow selection.

- the degree of permitting, rights-of-way, construction, operation and maintenance difficulty;
- risks associated with the construction, operation and maintenance of the transmission solution;
- technical and engineering design difficulty or whether specific expertise in design or construction is required;
- special circumstances or difficulty associated with topography, terrain or configuration;
- specific facility technologies or materials associated with the transmission solution;
- binding cost containment measures, including cost caps;
- abandonment risk; and
- whether the overall cost of the transmission solution impacts CAISO's prior determination of, and inclusion in, the comprehensive Transmission Plan of the more efficient or cost-effective solution during Phase 2 of the transmission planning process.

If the transmission solution adopted in Phase 2 involves an upgrade or replacement to an existing TO facility, the TO will construct and own such upgrade unless a project sponsor and the TO agree to a different arrangement.

Furthermore, if there are multiple qualified project sponsors and proposals for the same transmission solution, CAISO will select one qualified approved project sponsor based on a comparative analysis of the degree to which each project sponsor's proposal meets the qualification criteria and the selection factors. The CAISO tariff states that the purpose of this comparative analysis is to:[138]

[138] CAISO, *California Independent System Operator Corporation Fifth Replacement FERC Electric Tariff*, 12 August 2019, para 24.5.4.

> …take into account all transmission solutions being proposed by competing project sponsors seeking approval of their transmission solution and to select a qualified project sponsor which is best able to design, finance, license, construct, maintain, and operate the particular transmission facility in a cost-effective, efficient, prudent, reliable, and capable manner over the lifetime of the facility, while maximizing overall benefits and minimizing the risk of untimely project completion, project abandonment, and future reliability, operational and other relevant problems, consistent with good utility practice, applicable reliability criteria, and CAISO Documents.

Reflecting the evolving nature of the competitive regime, CAISO has conducted numerous rounds of stakeholder engagement to review and improve the competitive solicitation process. A range of improvements have been identified including the need for more clarity regarding selection criteria, which has been met by the utilisation of two external consultancies which provide advice to developers, whilst maintaining independence of evaluation.

A2.4 Planning and delivering large transmission investments in the ERCOT region of Texas

Transmission planning in the majority of Texas is the responsibility of the Electric Reliability Council of Texas (ERCOT) – the independent system operator. ERCOT manages approximately 90 per cent of Texas' electricity load, with the transmission network comprising around 75,000 kilometres of transmission lines. Another feature of the ERCOT region is that it is not subject to the Federal Energy Regulatory Commission's (FERC's) jurisdiction because electricity generated in the region is not transmitted in interstate commerce.[139]

An important consequence of the ERCOT region not being under FERC jurisdiction is that it is not required to comply with FERC Order 1000, which

[139] The authority of FERC to exercise jurisdiction arises when activities involve interstate commerce, ie, interstate transmission.

mandated that a competitive solicitation process be used in transmission investment. This lack of requirement is reflected in ERCOT's planning and investment approach, which mimics that of Australia where the independent system planner identifies the need, but the solution is ultimately allocated to the incumbent transmission operator. That said, competitive tendering has been used in ERCOT in the context of competitive renewable energy zones (CREZs).

In the remainder of this appendix, we discuss ECROT's standard planning and investment process as well as the special processes undertaken to develop transmission connections to CREZs.[140]

A2.4.1 Planning and delivery of transmission infrastructure

ERCOT's planning process is designed to support the Public Utility Commission of Texas' (PUCT's) finding that projects are necessary for service, accommodation, conscientious or safety of the public. In its role as system operator, ERCOT works collaboratively with the incumbent transmission operators to evaluate the need for transmission system improvements (and alternatives) based on economic and technical criteria.

The process, which is describe in detail below, does not give rise to substantial competitive tension, instead relying on administrative means for revealing efficient costs.

ERCOT's standard planning and investment process

Identifying needs and potential solutions to those needs in the ERCOT region is the responsibility of the Regional Planning Group (RPG). The RPG, which is lead and facilitated by ERCOT, is a non-voting, consensus-based group that comprises a range of stakeholders from the transmission industry, including:

- incumbent transmission operators;
- market participants;
- consumers; and
- PUCT staff.

The need for investment can be identified by any stakeholder as part of the RPG process – all stakeholders are allowed to submit projects for review.

Network needs are formally identified through the long-term system assessment (LTSA). The LTSA, which is conducted by ERCOT in coordination with the RPG on a biennial basis and reviewed annual, uses scenario analysis techniques to assess the potential needs of the system up to 20 years in the future. Whilst the LTSA does not identify specific upgrades, it evaluates indicative system upgrades under a range of scenarios to identify whether they are robust and whether possible alternatives may be more economic.

Aside for minor transmission projects, all transmission projects in the ERCOT region undergo a formal review by the RPG. The exact nature of the review process is dependent on which of four tiers the project is allocated to. An overview of the project tiers and their associated assessment requirements is provided in Figure A2.5.

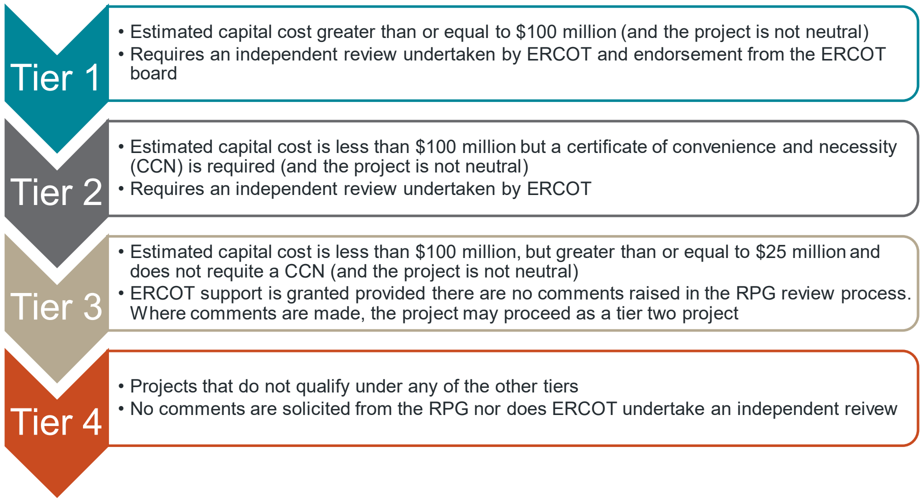
Parties that wish to submit a project for RPG review are required to set out the project's:

- description, including expected cost, feasible alternatives, transmission topology, modelling parameters and data, study cases used to generate results and maps and diagrams of options;
- reliability or economic problem that it solves;

[140] This appendix draws on material from: ERCOT, *ERCOT Planning Guide*, 2 July 2018; ERCOT, *ERCOT Nodal protocols*, 10 October 2018.

- desired in-service date and feasible in-service date; and
- analysis of rejected alternatives.

Figure A2.5: ERCOT project tiers and corresponding assessment process



Notes: a neutral project is a project that consists entirely of the addition of or upgrades to radial transmission circuits, the addition of equipment that does not affect the transfer capability of a circuit, repair and replacement in-kind projects, projects that are associated with the direct connection of new generation, the addition of static reactive devices, a project to serve a new load (unless such a project would create a new transmission circuit connection between two stations), replacement of failed equipment and equipment upgrades that only result in ratings changes.

Proposed transmission projects are evaluated by ERCOT and the RPG using a range of tools and vary based on the tier of the projects. For instance, regarding tier 1 projects – which are subject to the most rigorous assessment – ERCOT:

- undertakes a generation sensitivity analysis to evaluate the effect that proposed generation resources will have on the recommended transmission project; and
- evaluates impacts related to load scaling used or any constraints resulting from projects.

The preferred solution is typically that which has the lowest cost over the life of the asset, subject to operational impacts and long-term system needs. Further, ERCOT is able to use its discretion when undertaking reviews such that an adequate solution to the identified need can be reached. Where necessary, the independent review undertaken by ERCOT consists of studies and analyses sufficient to determine whether the proposed project is needed and whether it is the preferred solution to the identified need.

Projects that pass the RPG review process are designated to the incumbent transmission operator of the relevant area. For example, transmission augmentations are allocated to the transmission operators whose network comprises the end points of the line. Transmission operators are able to delegate the responsibility to an alternative operator. Further, if the designated transmission operator is not cooperating sufficiently to progress the investment, ERCOT may solicit interest from other transmission operators and transfer the responsibility to build, own and operate the asset.

ERCOT's standard regime relies on administrative means for revealing efficient costs

As with other jurisdictions in the United States, transmission operators in the ERCOT region are subject to rate of return regulation. In other words, prices are set at rates that reflect infrastructure build and maintenance costs, administrative costs and regulatory expenses. Prices are updated when a transmission operator successfully applies for a revision to be made. These revisions are typically capped at occurring twice a year, though exceptions are made in light of exceptional circumstances.

The tariff revision process is the primary means by which rate of return regulation provides incentives to reveal efficient costs. If additions to the rate base are not considered reasonable and necessary, the PUCT can exclude the expenditure from the rate base. Further, the PUCT may also estimate the over-recovery and reconcile it through a refund process.

In addition to the rate review process, there a number of features of the regulatory framework that incentives the revelation of efficient costs, including:

- requiring transmission lines to be granted a certificate of convenience and necessity, which requires the PUCT to consider the adequacy of the existing service, the need for additional service and the effect of granting the certificate (amongst other factors);[141]
- protocols that mandate additional project review and explanation in circumstances where:[142]
- there are significant modifications to an ERCOT endorsed project; or
- for economic driven project, there is increase in the estimated project costs from those endorsed by ERCOT of more than ten per cent; and
- stakeholder and ERCOT scrutiny prior to project approval; and
- independent review by ERCOT.

A2.4.2 Planning and delivering transmission connections to renewable energy zones

In 2005, Texas faced continued expansion in demand for renewable power. However, since the majority of readily available renewable generation was wind power sourced from wind farms in rural plains far from demand centers, two key issues emerged:

- constrained transmission networks that were already reaching these areas; and
- the coordination problem between generators and transmission operators, ie:
- transmission builders were reluctant to develop new infrastructure where wind projects had not yet been built; while
- wind developers were reluctant to build generating units where there was no connection to the transmission network.

To overcome these issues, and so secure access to cheap and environmentally sustainable renewable energy, CREZs were established. The plan, which was developed to deliver renewable energy in a manner most beneficial and cost-effective for costumers, placed increased emphasis on encouraging efficient costs through competition relative to the standard regime.

The preliminary development of CREZs

The development of CREZs was progressed in 2005 via Texas Senate Bill 20, which required the PUCT, with consultation and advice from ERCOT, to identify CREZs where there were readily exploitable renewable energy assets, especially wind power, without adequate transmission available. Additionally, this required that a transmission plan be developed to deliver renewable power from CREZs to consumers.

The first set of tasks considered by the PUCT required it to establish which CREZs were needed, and to develop preliminary estimates of the maximum generating capacity that would need to be transmitted. Promising areas for development were identified by ERCOT, which highlighted the wind energy production potential in Texas, and the transmission constraints that were most likely to hinder the delivery of electricity from wind energy resources.

Reflecting the litigious nature of regulatory frameworks in the United States, the preferred location of CREZs was further informed by a public hearing conducted by PUCT. The research undertaken by ERCOT, coupled with the

[141] 16 TAC § 25.101, Public Utility Regulatory Act (1997) § 37.056

[142] ERCOT, *ERCOT Nodal protocols*, 10 October 2018, 3.11.4.10.

public hearing, culminated in an order by the PUCT that designated five areas of the state as CREZs (Panhandle A, Panhandle B, McCamey, Central and Central West), and determined the maximum generating capacity that was expected to be transferred.

Following the selection of the location of the CREZs, the related tasks of determining what transmission investments would deliver energy from these locations, and which transmission operators would be responsible for constructing these assets remained.

This process was shaped by the PUCT, which deemed that it would be necessary for ERCOT to study four aggregate tiers of megawatt transfer capability identified for the designated CREZs, and directed ERCOT to develop a CREZ Transmission Optimization Study (CTO) which:

- determined what transmission infrastructure was necessary to transmit generation capacity to population centres; and
- produced different scenarios comprising various system configurations and power capacities, with varied costs.[143]

The objective of the study was to independently identify and evaluate which transmission proposals would produce the most beneficial and cost-effective transmission solutions under each transfer capability scenario. To inform its report, ERCOT conducted stakeholder workgroups over a 6-month period and tested numerous alternative transmission solutions.[144]

To supplement the report, a study by General Electric (GE) was produced to determine the level, type, and cost of additional ancillary services to maintain the reliability of the grid. The report concluded that it is possible to integrate any of the levels of wind studied in the report without compromising reliability.

These studies were again complemented by a public hearing and formed the basis on which the PUCT selected the major transmission improvements necessary to deliver energy generated in the CREZs to customers, in a manner that is most beneficial and cost-effective to customers. This included identifying the requirements for new and upgraded lines, and other improvements to the grid, as well as updating the maximum expected generation capacity. Indeed, in 2008, the PUCT selected Scenario 2, which would accommodate 18.5 GW of wind, cost $6.8 billion, and consist of approximately 3,600 circuit miles of 345 kV transmission.

The CREZ process utilised competition to encourage efficient costs

Efficient costs are encouraged through competitive tendering, which was used to determine who would build, operate and maintain the transmission capacity necessary to deliver renewable energy from CREZs. An iterative process of transmission operators submitting and refining proposals upon request from the PUCT was implemented. In selecting the appropriate entities, the PUCT considered a range of factors, namely:[145]

> the interested TSP's current and expected capabilities to finance, license, construct, operate, and maintain the CTP [CREZ transmission plan] facilities in the most beneficial and cost-effective manner; the expertise of the TSP's staff; the TSP's projected capital costs and operating and maintenance costs for each CTP facility, proposed schedule for development and completion of each CTP facility, financial resources, expected use of historically underutilized businesses (unless the TSP is an electric cooperative or municipally owned utility), and understanding of the specific requirements to implement the CTP

[143] Identified costs were incomplete, reflecting the timing of the study, and other simplifications, eg, it relied on standard per acre cost right of way development costs, utilised straight-line distances for transmission lines, and did not include financing costs such as interest rate applied to funds borrowed to build the CREZ projects within unit costs.

[144] Solutions were proposed by transmission operators.

[145] PUCT, *Docket No. 35665*, 30 March 2009, pp 1-2, 6-11.

facilities; and if applicable, the TSP's previous transmission experience and historical operating and maintenance costs for existing transmission facilities.

The commission emphasised various selection criteria:[146]

- **financial considerations** – the PUCT aimed to establish that interested transmission operators were financially capable, and so required provision of: projected costs; historical average direct operating and maintenance costs per mile of same voltage transmission lines (past five calendar years); estimated overhead rate for managing third parties; and current and projected financial resources;
- **priority projects** – the PUCT considered that priority projects (those considered critical to relieve current congestion) should be prioritised over other projects, and that incumbent transmission operators that own and operate existing facilities geographically proximate to these projects would be best placed to undertake them;
- **balance in selecting multiple entities as transmission operators** – the PUCT recognised the trade off between selecting a large pool of transmission operators to enable spread of financial risk, innovation and diversification of skills, and selecting a small number of transmission operators to reduce complexity and coordination difficulties, and so selected several incumbents and the strongest new entrants;
- **selection of municipally owned utilities** – the PUCT considered that a range of difficulties related to selecting municipally owned utilities, eg, that they are out of the PUCT's jurisdiction for routing;
- **proximity of facilities** – the PUCT considered there to be benefits related to transmission operator specific projects being geographically proximate, eg, an incumbent transmission operator's project being close to its pre-existing area;
- **size of transmission operators relative to assignment** – the PUCT considered interested transmission operator's current and future capabilities to handle new projects, with allocations reflecting transmission operator's experience with large scale energy projects, financial capacity and ability to expand; and
- **consideration of facilities requested by transmission operators** – the PUCT considered that the transmission operators' interest in particular projects, as indicated by proposals, was a valuable signal.

The transmission operators developing connections to CREZs had to bear the initial up-front costs for transmission investments and recovered funding from consumers post-development. Furthermore, the builder was guaranteed to recover the costs incurred in building new transmission assets.

Administrative means were used to further encourage efficient costs

In addition to the competitive tendering process, ERCOT and the PUCT implemented administrative measures to overcome possible inefficiencies resulting from the guaranteed recoverability of development costs. Aside from thorough planning, the PUCT implemented monitoring/oversight and reporting requirements.[147]

Project oversight involved delegating authority to an executive director to select, engage and oversee persons with responsibility for oversight of the planning, financing, and construction of all CREZ facilities to ensure timely completion. It was considered reasonable that the relevant transmission operators pay for project oversight and could recover the amount paid within project costs. In addition, new entrants were required to submit plans for operation, maintenance, and ongoing control of assigned CREZ facilities, as required by the Executive Director or project oversight monitor.

The reporting requirements set by the PUCT stipulate that:[148]

- within six months of the PUCT granting a certificate of convenience and necessity (CCN) for a CREZ transmission facility, transmission operators

[146] PUCT, *Docket No. 35665*, 30 March 2009, pp 6-11.

[147] PUCT, *Docket No. 35665*, 30 March 2009, pp 20-22.

[148] PUCT, *Docket No. 35665*, 30 March 2009, pp 54-56.

file cost estimates and schedules based on the latest available information, including certificates of CCN acquisition, right of way and land acquisition, engineering and design, procurement of materials and equipment, and construction of facilities, as well as information regarding the transmission operator's financing methods, costs, and schedules;

- during implementation of a CREZ transmission facility, any schedule change that is greater than 60 days for any of the estimated dates provided in the six-month report, the transmission operator must provide a detailed explanation of the reasons for the change within 30 days of becoming aware of the change, and must specify any change in method, costs, or scheduling for financing;
- at any time, transmission operators must report within ten working days of becoming aware of any change in circumstance that will affect the transmission operator's ability to complete a project, or that would change any of the most current cost estimates provided to the Commission by more than 15 percent;
- one year after CCN approval (and updated yearly until service begins), each designated transmission operator must file updated total cost for each of its CTP facilities requiring a CCN, as well as costs of right-of-way and land acquisition, engineering and design, procurement of material and equipment, and construction of facilities, and updated cost of financing; and
- to facilitate communication between transmission operators, each transmission operator must provide implementation reports to other transmission operators that are responsible for interdependent projects.

Furthermore, flexibility was enabled via allowances for the proposal of modifications for the purpose of improving capacity or reducing costs, with the PUCT directing ERCOT to undertake a review. Similarly, proposals which expedite the project's implementation timeline, promote other technical efficiencies, or are otherwise cost effective were submitted to ERCOT for review (including timely stakeholder input). If the proposed modifications impacted a project requiring a CNN, the PUCT made the final decision on adoption. Otherwise, ERCOT was to authorise cost effective minor projects which are consistent with the intent of the CTP.[149]

[149] Minor projects include modifications such as changes to line conductors, specifications of series compensation, adding substations and using existing transmission infrastructure for interconnection of generation.

A3. Delivering transmission investments in the United Kingdom

The Office of Gas and Electricity Markets (Ofgem) is responsible for regulating the electricity and gas industries in Great Britain, and so protecting the interests of existing and future energy consumers. Within its role, Ofgem has contributed to the development of numerous policies that promote the use of renewable energy, and further, the economic and efficient supply of electricity to Britain's grid. Regarding electricity transmission, Ofgem regulates both offshore and onshore regimes.

Whilst, in its current form, Ofgem's onshore regime is similar to that implemented in the NEM, Ofgem has been working to introduce competitive tension within transmission. This followed the successful introduction of competition in the development of offshore transmission assets, which connect floating wind farms to the onshore network. However, the implementation of an onshore regime which encourages competition has been limited due to a range of issues, eg, difficulties with legislative change.

In the remainder of this appendix, we discuss Ofgem's offshore transmission regime as well as the regime used to regulate onshore transmission.

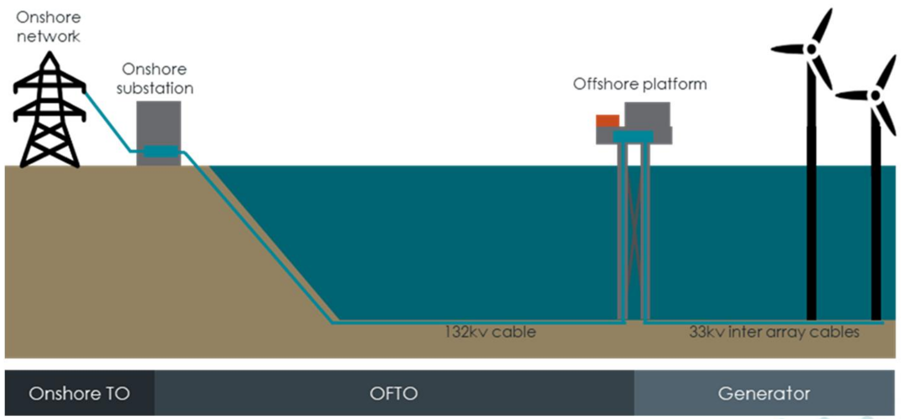
A3.1 The offshore transmission regime

To promote the achievement of the government's renewable energy targets, Ofgem partnered with the Department of Energy and Climate Change (DECC) to establish the competitive offshore transmission regulatory regime. The approach, which was implemented by Ofgem in 2009, is dynamic relative to traditional network investment, open and competitive, with the purpose of encouraging innovation, new sources of technical expertise and finance. Whilst the regime emphasises competition, it also utilises numerous administrative measures to promote efficient costs.

A3.1.1 Offshore developments

Under the offshore transmission regime, an investment is identified by generators (or developers) which desire to develop an offshore wind generation facility. Given the isolated nature of these facilities, offshore transmission assets, which are owned and operated by offshore transmission operators (OFTO), must be developed to connect the generator to the grid, as shown in Figure A3.1 below.

Figure A3.1: Relationship between parties



Note: The assets transferred to the OFTO under the Generator Build model typically include the offshore substation; the transmission export cables, the onshore substation and ancillary equipment. The assets are radially connected. Source: Ofgem.

At present (ie, under the enduring regime), generators face two options for developing the offshore transmission assets:

- **the OFTO build option**, where the developer obtains the connection offer and undertakes high level design and preliminary works, whilst the OFTO constructs, operates, maintains and decommissions the transmission assets; and
- **the generator build option**, where the developer carries out the preliminary works, procurement and construction of the transmission assets, whilst the OFTO operates, maintains and decommissions the transmission assets.

As transmission assets must be owned and operated by an OFTO, the options represent a choice between tendering a completed asset or tendering the development of the asset as well as its operation and ownership. Further to this, given that the OFTO build option is yet to be adopted, the generator build option appears to be preferred by developers.[150]

To be eligible for tender, Ofgem must determine that the project meets, or will meet, the qualifying project requirements, as described in Table A3.1.[151]

Table A3.1: Generator build tender and OFTO build tender qualification requirements

Paragraph	Generator build tender	OFTO build tender
(a)	Developer has entered into a bilateral agreement with the holder of a co-ordination licence in accordance with the arrangements for connection and use of the transmission system.	Developer has entered into a bilateral agreement with the holder of a co-ordination licence in accordance with the arrangements for connection and use of the transmission system.
(b)	Developer has entered into an agreement for lease of the seabed.	Developer has entered into an agreement for lease of the seabed.
(c)	Developer has obtained all necessary consents and property rights for the transmission assets to be constructed and maintained and ensured that any such consents or property rights which are capable of being assignable to the successful bidder are so assignable.	Developer has obtained, or secured financing to obtain, the notified preliminary works for the transmission assets and provided the Authority with evidence in writing of how preliminary works that are not yet obtained, will be obtained.
(d)	Developer has completed construction of or entered into all necessary contracts for the construction of the transmission assets and ensured that any such contracts are assignable to the successful bidder.	Developer has satisfied the Authority that the terms of each construction phase contract, if any, are conducive to the development of an efficient, coordinated, and economical system of electricity transmission.
(e)	Developer has secured financing to construct the transmission assets.	Developer has provided the Authority with evidence in writing of its commitment to secure financing to construct the relevant generating station.

Source: Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2015

In addition to qualification requirements, entry conditions apply to developers. These vary for generator build tender and OFTO build tender, but together involve the developer agreeing to provide information to Ofgem, to operate in an efficient manner, and to comply with other conditions that Ofgem consider necessary in relation to the qualifying project [152]

Ofgem utilises a competitive tendering process to determine the developer of assets. Indeed, this process has undergone iterative adjustments since its initiation in 2009, which reflect Ofgem and stakeholder learnings. For

[150] PwC, *Offshore transmission*, Market update, October 2018, p 5.

[151] A project which fails to qualify for a tender round may be considered for subsequent rounds. The qualifying project requirements are defined in Schedule 1 of *the Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2015*. A per paragraph 3, Ofgem may consider deem that a project meets the requirement if the developer provides an undertaking to meet the requirement within a defined timeframe.

[152] Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2015, Schedule 2.

example, the sixth tender round introduced a 25 year revenue term (previously 20 year) and provided greater tender guidance.[153]

The process by which the successful bidder of a generator build tender is selected, which is summarised in Figure A3.2, involves the following stages:

1. **qualifying projects and tender start** – a project must qualify and meet tender entry conditions;
2. **enhanced pre qualification (EPQ)** – a shortlist of interested bidders is formed, ie, the EPQ stage:
    a. provides full instructions on how and what bidders should submit;
    b. involves assessment based on the a range of factors, eg, economic and financial standing, and technical and professional ability;
    c. develops a shortlist of eight (as at tender round 6);
    d. includes a second EPQ stage is held if there are too few bidders; and
    e. has a passporting process, introduced in tender round 6, which means that bidders only need to obtain one EPQ award that will remain valid for the full tender round (unsuccessful bidders may reapply for later projects/stages.
3. **invitation to tender (ITT)** – a preferred bidder is identified, which involves;
    a. Ofgem evaluating bidders' proposals for financing, managing and operating a specific OFTO project;
    b. qualifying bidders being granted access to additional data from the project developer, which assists bidders in making an investment decision and in structuring their bid;[154]
    c. the evaluation criteria, which vary by project, are based upon an evaluation of the financial and non-financial deliverability of the bidders' submissions;[155] and
    d. the possible identification of a reserve bidder.
4. **best and final offer (BAFO)** – a discretionary step that Ofgem may request if it considers that it will provide the opportunity for the generation of further value, or where the ITT responses have not been sufficient to select a preferred bidder;
5. **preferred bidder (PB)** – a period of due diligence whereby the preferred bidder and developer agree on arrangements for transferring the assets, followed by a 28 day public consultation on amendments to the OFTO licence, which involves:[156]
    a. the adjustment of the tender revenue stream (TRS) if necessary and the request is permissible;[157]
    b. the determination of the methodology for, and calculation of the market revenue adjustment;[158]
    c. the calculation of the final transfer value, which is reflective of the economic and efficient costs that ought to have been incurred in

[153] Further description will principally focus on the most recent approach, ie, that applied in tender round 6. Ofgem, *OFTO Tender Round 6 (TR6)*, Launch Event, 9 October 2018; PwC, *Offshore transmission*, Market update, October 2018; Ofgem, *Offshore Electricity Transmission Tender Process Guidance Document*, 30 November 2018.

[154] This information includes contracts, leases, warranties, project financials, seabed surveys and evidence of compliance with applicable legislation and regulations.

[155] For tender round six, evaluation placed a 100 per cent weighting on price, with quality criteria being set as a pass/ fail, rather than also being scored, ie, all bidders were firstly evaluated on their quality submission, with the preferred bidder achieving the highest price score or lowest submitted bid.

[156] These are all undertaken by Ofgem.

[157] Possible examples of a permissible change may include changes to underlying market rates, changes to the indicative transfer value, updates to the final transfer agreement and, material changes regarding the transmission assets.

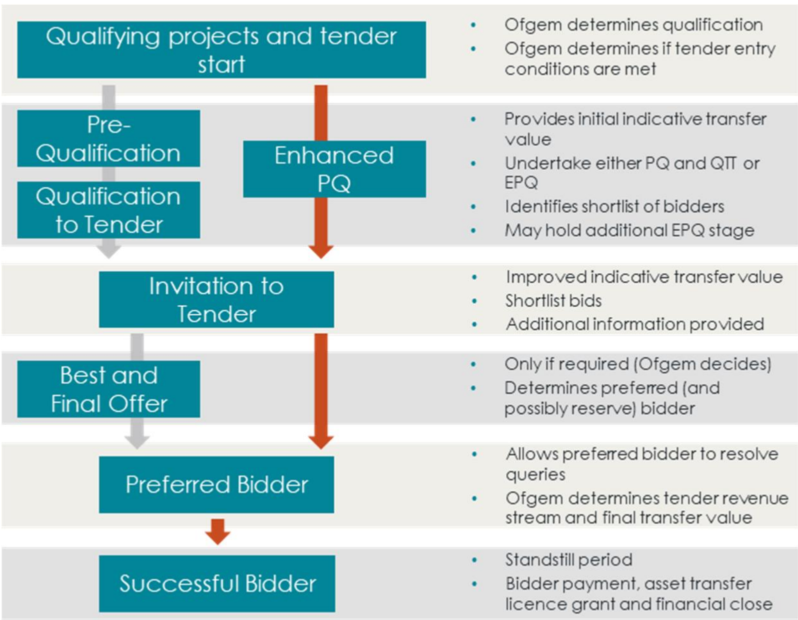
[158] The purpose of this is to ensure that the OFTO is not affected by underlying market rates.

connection with the development and construction of the relevant transmission asset;[159] and

d. if the reserve bidder becomes preferred, this stage restarts; and

6. **successful bidder** – all relevant financial close and asset transfer activities take place and the licence is granted.

Figure A3.2: Generator build tender process



Source: Ofgem, Offshore Electricity Transmission Tender Process Guidance Document, Guidance, November 2018, pp 14, 29-55.

There are two possible OFTO build options available, which follow a similar process to that described above:[160]

- **early OFTO build** – following the generator obtaining a connection offer, the OFTO bids its approach to aspects of preliminary works, consenting, design, procurement, financing, construction, operation, maintenance and decommissioning of the transmission assets and the costs associated with these activities; and
- **late OFTO build** – following the generator undertaking preliminary works, consenting and high level design of the transmission assets, the OFTO bids its approach to procurement, financing, construction, operation, maintenance and decommissioning of the transmission assets and the costs associated with these activities.

A3.1.2 Competition to encourage efficient costs and charges

The available models provide different opportunities for competitive tension, ie, under the generator build model, competition is over the operation, maintenance and commissioning, whilst competition under the OFTO build model extends to the build process. In essence, the allowed RAB is determined post construction in the case of the generator build model, whilst the allowed RAB is determined pre-construction in the case of the OFTO build model. As such, under the OFTO model, competition encourages further efficiency gains within the build phase, which may in turn promote further cost efficiency.

[159] This is only completed once the transmission assets are available for use for the transmission of electricity.

[160] Ofgem, *OFTO Build: Providing additional flexibility through an extended framework, Updated policy proposal*, December 2014, para, 1.4.

Relative to the OFTO build model, the OFTO build tender process promotes efficient costs through:[161]

- reducing construction funding requirements faced by generators and increasing sources of alternative funding;
- enabling an OFTO to take a whole life approach to investment, which lowers overall cost of capital;
- providing early clarity and certainty as to capital expenditure and network charges;
- enhances scope of competition promotes downward pricing pressure;
- allows the best fit constructors to build transmission assets, so promoting downwards cost pressure.

A3.1.3 Administrative means for revealing efficient costs

Under the generator build model, the tendering process provides Ofgem with the ability to determine the amount of expenditure which it considers is reflective of the economic and efficient costs that ought to have been incurred in connection with the development and construction of the relevant transmission asset. As such, Ofgem ultimately determines the remuneration the developer receives for the asset. However, as described above, bidding ultimately determines how much expenditure is recovered from consumers.

Under both models the TRS, which is paid by the National Electricity Transmission System Operator (NETSO),[162] is included within the licence, as well as any uplift to be applied over the contract term. Furthermore, whilst there is no regulatory discretion for amending the TRS,[163] bonuses and deductions are made based on availability.

Given NETSO's obligation to pay the OFTO, even if the wind farm ceases to operate, NETSO continues to pay the OFTO.[164] Further, as a consequence of the fixed nature of the TRS, the OFTO has incentive to minimise maintenance and operating costs so as to maximise profits, without jeopardising availability payments.

A3.2 The onshore regime

The onshore regime applies to Great Britain's three TNSPs (or TOs), Scottish Hydro Electric, Scottish Power Transmission and National Grid Electricity Transmission – Figure A3.3.

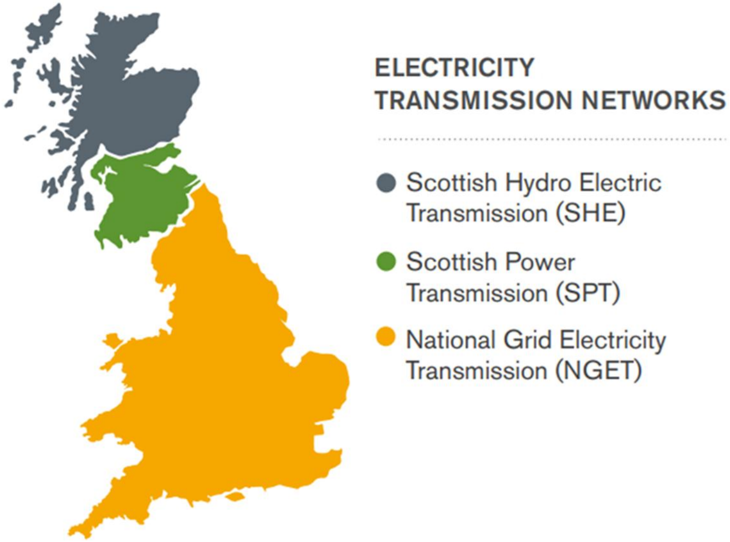
[161] Ofgem, *OFTO Build: Providing additional flexibility through an extended framework, Updated policy proposal*, December 2014, para, 1.12.

[162] Currently National Grid Electricity Transmission (NGET))

[163] In the case that the final transfer value is not calculated prior to finalisation, Ofgem may adjust the TRS to reflect the difference between the indicative transfer value and the final transfer value.

[164] However, the NETSO is underwritten by the consumer. PwC, *Offshore transmission*, Market update, October 2018, p 10.

Figure A3.3: Onshore transmission operators



Source: Ofgem.

In its current form, the regime is similar to that implemented in NEM as it provides little opportunity for competitive tension, aside for in the merchant environment. However, Ofgem have been progressing towards encouraging competition where possible, albeit slowly due to difficulties including legislation, ie:[165]

> In June 2017 we published an update on our plans to introduce competition to onshore electricity transmission, stating that we are deferring further development of the Competitively Appointed Transmission Owner (CATO) regime until the timing of the necessary legislation is more certain. We reiterated that we continue to consider that there are significant benefits to consumers in introducing competition into the delivery of new, separable, and high value onshore electricity transmission projects.

On 23 April 2020, after a period of statutory consultation, Ofgem finalised its decision to modify standard condition C27 of the electricity transmission license.[166] These changes, which take effect from 18 June 2020, include the requirement for the NGESO to assess certain projects described in the network options assessment (NOA) report against the criteria for competition, ie, if the projects are 'new', 'separable' and 'high value', competition should be introduced.[167] However, modifications to C27 relate to identifying potential projects for competition, rather than making decisions on application of competition and so further work remains.

The figure below describes some possible forms of onshore competition, as considered by Ofgem.

[165] Ofgem, *Update on competition in onshore electricity transmission*, 23 January 2018, p 2.

[166] Ofgem, *Decision on the modifications to standard condition C27 of the electricity transmission licence*, 23 April 2020; Ofgem, *Notice of the modifications to standard condition C27 of the electricity transmission licence*, 23 April 2020.

[167] Ofgem describes these criteria as follows:

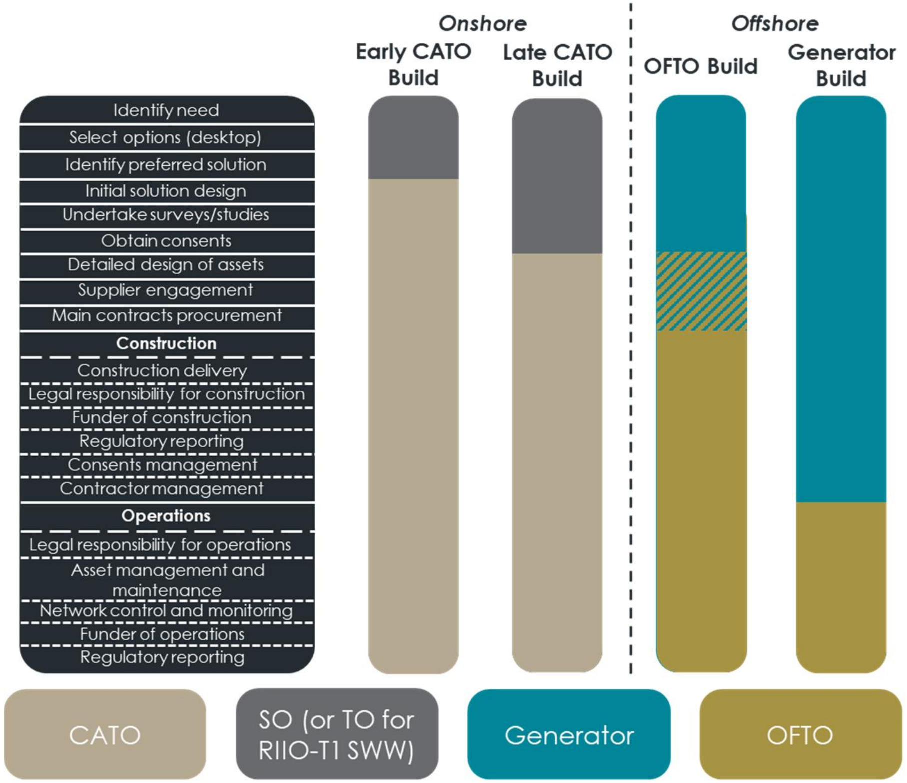
(a) new means 'a completely new transmission asset or a complete replacement of an existing transmission asset';

(b) separable means 'the boundaries of ownership between these assets and other (existing) assets can be clearly delineated', although assets do not need to be electrically contiguous or separable from other assets; and

(c) high-value means 'a threshold set at or above £100,000,000 of expected capital expenditure at the point of initial assessment of the appropriate delivery model', which is fixed in nominal terms and not indexed and includes construction costs, land costs, project management costs, and a range of further costs.

See: Ofgem, *Guidance on the criteria for competition*, 12 February 2019.

Figure A3.4: Ofgem's CATO options



Below is a description of numerous processes utilised under the current regime, which apply to large transmission projects.

A3.2.1 Strategic wider works costs are regulated via administrative means

The strategic wider works (SWW) arrangement, which was introduced as part of the RIIO-T1 electricity transmission price control, is used to assess large transmission projects that are needed to extend and strengthen the transmission network, as well as transfer electricity from generators to consumers.[168] The arrangement applies to projects which meet the following criteria:

- the project will deliver additional transfer capability capacity or wider system benefits;
- costs cannot be recovered under any other provision of the TO's price control settlement; and
- total expected delivery cost exceeds those specified in Table A3.2

Table A3.2: Thresholds for each company

Company	Cost threshold
Scottish Hydro Electric Transmission Plc	£50m
Scottish Power Transmission Ltd	£100m
National Grid Electricity Transmission Plc	£500m[169]

The SSW arrangement, which is summarised in Table A3.3 below, is largely similar to the contingent project arrangement applied in the NEM. Here, a TO identifies an opportunity, investigates costs and designs, and proceeds to

[168] Applies until 31 March 2021, after which RIIO-T2 will apply.

[169] Projects with smaller capital costs may be considered as an SWW project if certain criteria are met, as defined in National Grid's Networks Options Assessment, which is updated annually.

apply for approval for an adjustment to its allowed expenditure recoverable from consumers.

Table A3.3: Summary of SWW arrangements

SWW arrangements	TO's role	Ofgem's role
1. Assessment		
Eligibility assessment[170]	Formally advises Ofgem of new SWW proposal and provides accompanying information which show project eligibility. Reflecting its statutory obligation to develop and maintain the transmission system in an efficient, coordinated and economical manner, the TO is responsible for driving all SWW projects.	Review whether proposal is eligible for assessment under SWW arrangements.
Initial needs case	Submits initial needs case (including CBA from SO).	Verify future system requirement for additional capacity and review TO's optioneering. Assess case for TO developing its preferred option. Intend to assess whether project is suitable for competition. Consult on initial views arising from assessment and issues under consideration. After considering consultation responses, decide whether all or parts of project may be suitable for competition, or delivery through an alternative model intended to deliver the benefits of competition.
Final needs case	Submits final needs case (including CBA from SO).	Assess whether the need for proposed reinforcement is well justified. Ensure the proposed reinforcement provides value for money for existing and future consumers. Consult on views arising from assessment and issues under consideration.
Project assessment	Submits detailed plans about design, costs, delivery and managing risks for the project.	Assess the TO's delivery plans and proposed costs to deliver the SWW output by the proposed completion date. Ensure proposal is cost efficient and TO is ready to proceed according to the proposed project timelines. Consults on initial views and proposals for SWW output to be delivered, efficient costs, and scheduled completion date.
2. Decision and implementation		Publish decision on whether project is in interests of consumers. If so, specify a new SWW output for TO to deliver and adjust the TO's RIIO-T1 allowed expenditure. Propose and consult on licence changes. Direct licence modification
3. Construction	Reports on progress, expenditure and any Cost and Output Adjusting Event	Monitor progress and actual expenditure against allowed expenditure. Ensure timely progress towards delivery of SWW outputs.
4. Monitoring	Advises on the delivery of outputs.	Monitors the TO's performance in the delivery of the outputs.

Source: Ofgem, Guidance on the Strategic Wider Works arrangements in the electricity transmission price control, RIIO-T1, November 2017, p 43-44.

A3.2.2 Interconnectors are competitively identified with the option for administrative regulation

In 2014, the GB electricity market had 4GW of interconnector capacity, sourced from France (2GW), Netherlands (1GW), Northern Ireland (500MW) and the Republic of Ireland (500MW). Indeed, Ofgem considered that its regime did not deliver the right level of interconnection.[171] This was mainly the

[170] Where a proposed reinforcement has already been shown as suitable for assessment under the SWW arrangements, Ofgem may not review the eligibility of the proposal.

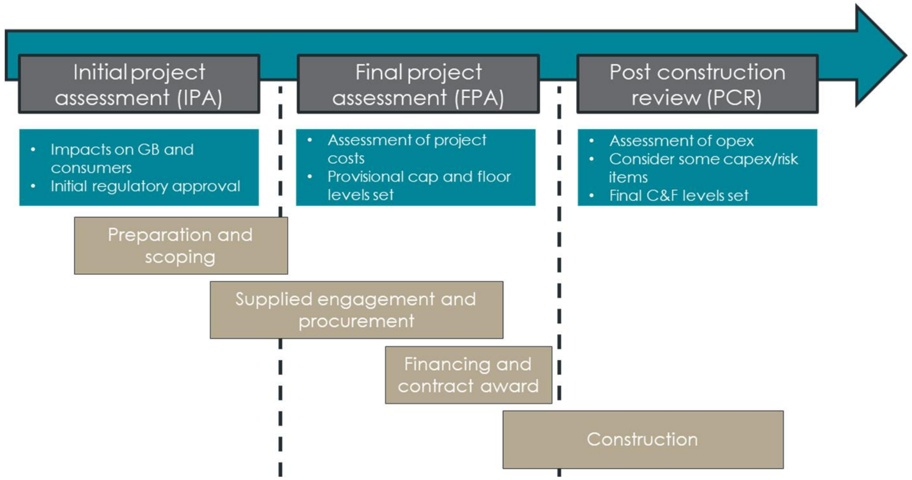
[171] Ofgem, *Proposal to roll out a cap and floor regime to near-term projects*, May 2014, p 8.

consequence of the regime exposing interconnector developers to market (revenue) risk, without any consumer underwriting, ie, developers did not receive any guaranteed regulated revenue and faced full downside risk related to interconnector use.

Through reforms throughout 2013-2014, Ofgem sought to overcome this issue which was stymieing developer led interconnection. Indeed, it introduced a develop-led cap and floor regime. Notably, developers maintained the option to lead the development with no consumer underwriting. The cap and floor regime, which sets a minimum and maximum return that interconnector develops can earn, was developed for NEMO Link and subsequently extended it to other interconnectors in August 2014.[172] These stages involved are summarised below in Figure A3.5.

[172] Ofgem, *Decision on the Post Construction Review of the Nemo Link interconnector to Belgium*, Final decision, December 2019, p 8.

Figure A3.5: Interconnector development process



Source: Ofgem, Decision on the Post Construction Review of the Nemo Link interconnector to Belgium, December 2019, p 8. See also Ofgem, Decision to roll out a cap and floor regime to near term electricity interconnectors, August 2014, Appendix 1, pp 7-8; Ofgem, Proposal to roll out a cap and floor regime to near-term projects, May 2014, pp 44-50.

The three stages considered are:

- the initial project assessment (IPA), where Ofgem assess the needs case for new interconnector projects, using an economic assessment which accounts for the total costs and benefits of the interconnector and its likely impact on consumers;
- the final project assessment (FPA), where Ofgem confirm the application and provision levels of a cap and floor regime, assess the efficient costs associated with developing, constructing, operating, maintaining and decommissioning of the interconnector, set the project's financial

parameters, develop a project-specific financial model, and set incentive values;

- the post construction review (PCR), where Ofgem confirms the cap and floor levels, revises the components of the cost assessment that were not fixed at the FPA stage, and assesses the efficiency of costs incurred during construction.[173]

The cap and floor levels, which are set using a building blocks approach based on development costs, capital costs, operating and maintenance costs, replacement costs, decommissioning costs, tax and allowed return, may thus develop between prior construction and post construction. A high level description of the regime is set out in Table A3.4.

Table A3.4: High level aspects of interconnector regime

Characteristic	High level description
Regime length	25 years.
Cap and floor levels	Levels set at the start of the regime and remain fixed in real terms for 25 years from the start of operation.
Availability incentive	The cap varied by +/- 2% depending on performance against an availability target. The floor only applies if a minimum availability threshold is met.
Assessment period (assessing whether IC revenues are above or below cap/floor)	The base case is 5-year assessment periods. There is also the option of within-period annual adjustments.
Mechanism	If revenue is between the cap and floor, no adjustment is made. Revenue above the cap is returned to consumers and shortfall of revenue below the floor requires payment from consumers (via transmission charges).
Assessment of efficient costs to inform cap and floor levels	Ofgem will assess efficient capex costs ahead of construction, with limited, specific reopeners. Similarly, Ofgem assesses opex costs ahead of the project becoming operational with limited re-openers.

Source: Ofgem, Proposal to roll out a cap and floor regime to near-term projects, May 2014, p 19.

[173] In the NEMO link PCR, Ofgem also assessed operating, maintenance, replacement, and decommissioning costs. Ofgem, *Decision on the Post Construction Review of the Nemo Link interconnector to Belgium*, Final decision, December 2019, p 9.

A4. Delivering transmission investments in Brazil

In 1995, the Brazilian government embarked on a major reform program which set to unbundle and privatise the Brazilian electricity sector. The reform allowed the financing of projects that Brazil could not otherwise afford and thus promoted security of supply, whilst also aiming to improve the efficiency of utilities, enhance competitiveness, and improve service quality.

Prompted by the reform, between 2000 and 2010 approximately 70 percent of investments in transmission came from the private sector. Furthermore, this led to Brazil sustaining approximately 65 private and government owned transmission companies, the largest of which is federal owned Electrobas, which owns approximately 57 per cent of Brazil's transmission assets.[174]

In the remainder of this summary, we discuss Brazil's planning and investment process, highlighting its focus on promoting efficient costs through competition, as well as the additional administrative means implemented.

A4.1 Brazil's planning and investment process

The Ministry of Mines and Energy (MME), which is responsible for power sector policy, is tasked with identifying the need for investment.[175] This is completed through research and input from both the Operator of the National Electricity System (ONS), which is the system operator and ensures that power supplied to the national interconnected system (SIN) is continuous, high quality and cost-efficient, and Empresa de Pesquisa Energética (EPE), which is a company that is responsible for undertaking strategic research within the electricity and energy sectors.

Three types of reports are used to plan and identify system needs:[176]

- a long term (10 year) plan prepared by EPE, which is indicative and helps inform future needs;
- a short term (5 year) plan prepared by EPE, which determines the required investment in new transmission lines, is updated yearly and forms the basis for tenders; and
- a three year document prepared by ONS, which identifies reinforcement and extension projects.

Preferred developments are determined through EPE's short term plan, which identifies projects that are considered appropriate for development. That is, the planning process allows the development of a prescriptive solution to the identified need. These prescriptive solutions, which classify length, capacity and design, are then tendered for through auction.[177]

[174] 30 per cent of which was from foreign companies, and 39 per cent which was from local private companies; World Bank Group, *Linking Up: Public-Private Partnerships in Power Transmission in Africa*, 2017, pp 75 and 77.

[175] Within its role, the MME is responsible for planning, granting transmission line concessions, and issuing bidding process guidelines for public services concessions.

[176] All plans require MME approval.

[177] Contracts and lot annexes are available (in Portuguese) on ANEEL's website, eg, http://www2.aneel.gov.br/aplicacoes/editais_transmissao/documentos/ANEXO%207A_Colinas_Sobradinho.pdf.

A4.2 Competitive tendering is utilised to promote efficiency

The primary means by which cost efficiency is encouraged in Brazil is through competitive tendering. Specifically, competitive tendering is used to award 30 year build own operate transfer (BOOT) contracts.[178]

The process, which is run by Brazil's energy regulator, Agência Nacional de Energia Elétrica (ANEEL),[179] begins with the release of a tender notice and technical specifications. To be successful, a bidder must meet criteria, ie:

- **technical** – the bidder must be registered with the CREA, which registers and regulates qualifications, and provide proof of contracts, commitment letters with relevant subcontractors and proof of experience in building, operating and maintaining transmission systems and substations with voltage exceeding or equal to 220kV;
- **financial** – the bidder must meet a minimum liquidity, equity and capital level, and fulfill fiscal requirements including tax compliance;
- **delays in past tenders** – the bidder cannot participate for a certain period if it has faced delays in past tenders.

Eligible bids are evaluated through a single stage reverse auction, whereby ANEEL sets a benchmark maximum annual revenue which functions as a price cap, and bidders subsequently propose discounts.[180] The firm which bids the eligible lowest proposed annual revenue (or the highest discount) wins the tender.[181] Once a successful bidder is selected, ANEEL publishes auction details including the size, location, winning party, price, and construction costs.

A4.3 Administrative means are also utilised, albeit with varying success

The main administrative means by which efficient costs are encouraged is ANEEL's selection of the benchmark annual revenue. This provides ANEEL with the opportunity to develop a maximum estimate of costs prior to construction. The competitive process is then used to specify the costs that transmission operators expect, as well as the expected returns.

Additionally, the regime allows the regulator to review aspects of prices during five year price determinations. This allows for the revision of items including the cost of capital, adjustments for efficiency gains, and minimum schedules and procedures for operating and maintenance costs. These adjustments, which began in 2012, have increased perception of regulatory risk. Further factors, such as an insufficient WACC, environmental issues and delays and funding difficulty, have led to a decline in successful tenders, ie, while 100 per cent of tenders received bids between 2005 and 2009, 37 per cent of lots received no bids between 2012 and 2015.[182]

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[178] The contracts specify numerous requirements for the transmission company, including that it is responsible for obtaining environmental permits, that it must provide all third parties access, that it will be paid on the basis of availability, with penalties capped at 12.5 per cent of annual revenue for falling below 97 per cent availability, that it will be penalised for delayed commissioning, and that it must post a guarantee.

[179] ANEEL is responsible for a range of tasks including administering and supervising power sector concessions, regulating tariffs, settling administrative disputes, and developing the methodology and criteria for the determination of tariffs (both transmission and distribution).

[180] The benchmark is calculated based on various factors, ie, the cost of equipment, the depreciation rate of equipment, O&M costs, and the cost of capital.

[181] Annual revenue covers the firm's investment, as well as operational costs, maintenance costs and profit.

[182] World Bank Group, *Linking Up: Public-Private Partnerships in Power Transmission in Africa*, 2017, p 77.

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