6 SEPTEMBER 2018

INVESTMENT TESTS FOR TRANSMISSION NETWORKS

FINAL REPORT

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Executive Summary

1. In common with many other parts of the world, Australia's National Electricity Market (the "NEM") – which is the electricity wholesale market for the eastern and southern states of Australia – is undergoing unprecedented change in the transition to a low carbon system. Technical, environmental, political and economic factors are driving changes in the way energy is produced – with a greater emphasis on renewables production such as solar photovoltaic ("solar PV") and wind generation, and the progressive retirement of aging thermal generation, particularly coal-fired generation. Equally, customers' needs are also evolving with the roll out of smart meters, increasing digitisation and the potential large-scale transition away from the internal combustion engine to electric vehicles. Furthermore, technological developments in batteries and other storage assets mean electricity may increasingly be stored in greater volumes (and more cheaply) than has historically been possible.

2. In light of these developments, it is unsurprising that the role of electricity transmission – the network of high voltage electricity cables that enables electricity to be conveyed from producers to consumers or on to neighbouring networks for onward transportation – will also need to evolve. Over the course of the 20th Century, as electricity systems developed across the globe, transmission networks played an increasingly critical role in ensuring the:

   - reliability of systems' electricity supply by ensuring that electricity can be conveyed to where it is required at all times; and

   - overall affordability to society by enabling the delivery of electricity from lower cost sources of production to the centres of load.

3. Prior to the liberalisation of the energy sector, transmission networks were typically jointly owned with generation, in vertically-integrated entities. This meant, in theory at least, decisions on generation and transmission network investments within the boundaries of their respective jurisdictions could be taken by a 'single decision maker'. In practice, the effectiveness of this coordinated decision making depended on local circumstances.[1]

4. However, a global trend in the 1980s and 1990s was that policy makers sought to increase the efficiency of the electricity sector by privatising generation companies and introducing competition into the generation sector. The overarching concept was that profit-seeking generating companies would compete to meet the demand for electricity by providing consumers efficient and cheaper generation which would, in turn, reduce prices. Over time, the competitive market prices were also intended to incentivise more efficient generation technologies to enter into the market and displace older more costly plants. In short, the new electricity markets of the 1990s were intended to incentivise both short-term, operational efficiency and long-term investment and closure decisions of privately-owned generating plants.

5. A critical area in the liberalisation process was how to develop the market to provide reliable and efficient price signals for wholesale market participants to respond to. While the US and Europe developed different models, all electricity market designs sought to send price signals to generators to reward operational and investment efficiency. A key aspect of incentivising investment efficiency was to provide generators an incentive to site new generating units in the geographic locations on a network where it would be most valued – for example close to a demand centre served by high cost generation or where there was surplus transmission capacity.

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[1] For example, in the US we are aware that there would often be tensions between different parts of the vertically integrated utility on investment decisions. By contrast, the Central Electricity Generating Board ("CEGB") of England and Wales was considered to have had relatively integrated decision-making between transmission and generation.

6. It was also considered whether a similar approach might be extended to investment in the transmission sector. For example, investors might, in response to price signals, choose to invest in transmission assets that allowed them to capture the revenues from allowing low cost electricity to flow to meet demand served by higher cost electricity. Such an approach was intuitively attractive to policy makers and academics at the time as it would mean investment in generation *and* in transmission would be driven by price signals which in turn, the thinking went, would lead to greater efficiencies. Furthermore, it was in line with the prevailing market ethos of the time in that it would devolve decision making and negate the need for centralised planning.

7. However, the so-called merchant transmission investment model has been identified by many commentators (notably academics such as Joskow and Tirole in 2015, for example)[2] to suffer from a number of 'market failures'. Most significantly, as transmission investments are large and 'lumpy' in nature, merchant-based investors would find it hard to capture the required economic rent to invest in these assets.[3] Additionally, as beneficiaries of the transmission investment are likely to be dispersed geographically and change over time, this complicates how to coordinate and capture those willing to fund the investment. Hence, while the merchant model could potentially deliver some investments, overall it would, most likely, under-deliver.

8. Hence, as the 'market' alone cannot be relied on to deliver the appropriate amount of transmission investment, there has been an ongoing need to regulate some transmission investment and recover the costs of the network through mandatory charges on network users. Also, this has meant that there has been an ongoing need for a transmission planning function to ensure the transmission requirements of consumers are met appropriately.

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2 Joskow and Tirole (2005), Merchant Transmission Investment.

3 This issue might be more pronounced in the NEM context where an interconnector might account for a more substantial proportion of generating capacity in each region. This discrete and 'lumpy' investment would have a greater effect in reducing the existing price differentials to a point where the economic rent available would not justify the investment cost in the first place.

9. In addition to the need for a transmission planner, the *role* of the transmission planner has inevitably changed over time. Throughout the 20th Century, growth in electricity demand tended to be directly related to general economic activity and tended to grow in line with economic expansion. The prevailing technologies at the time meant this increasing demand for electricity was historically met at lowest cost through the development of new very large power stations (typically using a mixture of thermal, nuclear or hydro technologies). The role of the transmission planner was to connect these large power stations with the increasing demand. As noted already, in the liberalised market, policy makers aimed to influence the siting decisions of commercial, independent power stations by varying price signals across location.

10. In recent years, however, concerns over climate change have led policy makers in most developed economies to introduce decarbonisation objectives. This has resulted in a considerable increase in renewables generation. Moreover, because renewables technologies have typically required subsidies to induce entry, the price signals created by the electricity market have become less reliable. Rather, in recent years, investment in new (mostly renewables) generation has been less influenced by the market, as per the original aspiration of the liberalisers of electricity markets, and more by policy makers' preferences.

11. Therefore, while transmission investment of the past was planned on the basis of delivering electricity generated in a competitive wholesale market to end-consumers cheaply and securely, concerns over climate change have meant a third factor – that of sustainability – has now also become a critical factor in driving transmission investment in some countries. Transmission planning now has to drive the need to address a combination of faster renewables deployment, slower electricity demand growth (both in terms of annual consumption and peak demand) and retiring thermal generation.

12. These changes are, to a lesser or greater extent, a global phenomenon rather than unique to Australia. And, it is in this context, that the Australian Energy Market Operator ("AEMO") has commissioned the energy teams of FTI Consulting and its subsidiary company Compass Lexecon (together "FTI-CL Energy") to prepare a report on current international practice for deciding upon and agreeing investments in new transmission capacity, and to identify areas where practices in the National Electricity Market ("NEM") differ from wider international precedent.

13. This report focuses on the various ways in which different jurisdictions across the globe consider the case for an investment in transmission – which we refer to as an investment test. Wider issues on the entire transmission planning process such as the role of different parties in the decision-making and approval processes and the way in which costs and benefits are allocated, are considered in a separate FTI-CL Energy report.

14. We evaluate four features of investment tests across various international jurisdictions and compare them to the NEM's Regulatory Investment Test for Transmission ("RIT-T") approach.

15. First, regarding the **approach to meeting transmission needs**, jurisdictions in Great Britain ("GB") and the United States ("US") apply different tests for different asset types. In GB, specific investment tests are have evolved for different transmission asset classes such as onshore assets, transmission cables that link to a neighbouring region's or country's electricity system (known as interconnectors), and offshore transmission assets required to connect offshore wind farms. In the US, different investment tests are designed for different needs of transmission investment, such as from an economic, reliability or public policy perspective. This contrasts to the approach of the RIT-T, which has a 'one-size-fits-all' approach.

16. Second, regarding the **methodology of investment tests**, investment tests typically apply a form of cost-benefit analysis ("CBA") to calculate the net benefit of a potential solution to meet a system need against a range of potential future scenarios. The general approach to the scenarios is similar across many jurisdictions, describing different pathways for the future evolution of the system in terms of demand and supply projections as well as input assumptions such as commodity prices and macroeconomic and policy factors.

17. However, the approach to the calculation, and to the weight attributed to the various costs and benefits differ, and there is no single best practice:

- There is no common approach to defining 'benefits'. Some jurisdictions, including the NEM, US and some of Europe estimate the total social welfare (i.e. benefits received by both consumers and producers and measured by the change in total costs of production). Other jurisdictions, however, attribute greater weight to consumer welfare – as measured in the price changes that consumers are likely to experience (e.g. GB interconnectors). Different approaches are also used in relation to the evaluation of hard-to-quantify benefits and option value;

- Discount rates used to calculate the net expected benefit of investments vary (social vs commercial) as does the scenario differentiation (e.g. RIT-T is unique in allowing discount rates to vary across investment options); and
- Discounting often relies on a fixed time horizon, typically shorter than the asset's economic useful lifetime. In the NEM, the time horizon captures the expected useful life of the asset.

18. Third, regarding the **process and application of the investment tests**, the system operator and/or regulator in other jurisdictions tend to have more involved roles in investment tests compared to the RIT-T. This is to facilitate information coordination, to provide an independent view on transmission planning, and for additional/complementary verification of the costs and benefits.

19. Fourth, some elements of the approach to **addressing potential market failures** through the investment test design also differ between the NEM and other jurisdictions. The US adopts a beneficiary-pays principle (although the application of this principle can be difficult). While there is no beneficiary pays model in Europe, *per se*, it is notable that, on occasions, classes of potential beneficiaries can find routes to provide financial support to underpin the construction of interconnectors that they believe will be in their economic interest.[4] In addition, investments in interconnectors across two distinct price zones (or, in the US case, between two Independent System Operator ("ISO") regions) are viewed as 'special cases' (i.e. regulator-led approach in GB and committee-led approach in the US). However, no jurisdiction appears to have effective coordination with gas network investments.

20. Overall, the RIT-T, which relies on a prescriptive approach, appears to have been successful in identifying relatively small incremental transmission investments. This is particularly useful for investments relating to augmentation of the network and (since 2017) replacement expenditure. However, recent consultation responses to AEMO suggests that RIT-T is seen by some market participants as less suitable for developing complex or strategic investments, notably where close coordination between transmission and generation investment is required.

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[4] For example, NorthConnect (a planned link between Norway and Scotland) is likely to facilitate greater exports from Norway and is being developed by Nordic generators , while Piemonte Savoia (a France-Italy link) is promoted by a group of Italian energy-intensive industrial customers that would be likely to benefit from increased imports of low cost electricity from France into Northern Italy. Indeed, arguably, in GB, the regulator, Ofgem, sanctions customer support of interconnector projects if it considers that GB consumers will benefit on account of increased imports.

21. International experience suggests that Australia is far from being alone in grappling with the challenges of identifying and delivering the right level and type of transmission investments. There are different approaches to investment tests that might provide helpful lessons for the NEM.

22. Therefore, based on our evaluation of international experience, the key suggested areas for further analysis in the NEM context are:

- #1: Explore whether investment tests for transmission networks in the NEM should distinguish between asset needs and/or asset types;
- #2: Consider the pros and cons of restricting the evaluation criteria to consumer surplus, and potentially congestion rents, rather than social welfare (which includes the change in total costs of production). In addition, continue to explore ways to value optionality and other material externalities;
- #3: Consider formalising the current practice of applying a single discount rate for all options assessed and consider whether the use of a social rate could be appropriate given that consumers are the beneficiaries (particularly if the benefits are 'societal');
- #4: Consider the most appropriate time horizon for the CBA (including the merits of fixed and variable time horizons);
- #5: Explore an expanded role for the SO and/or regulator, and explore alternative approaches to dispute resolution;
- #6: Consider a separate transmission planning process and investment test for interconnectors between states; and
- #7: Consider different approaches to cost recovery (which may be applied differently for different asset types).

1. Introduction

1.1 In common with many other parts of the world, Australia’s electricity markets, and the nature of its electricity system, are undergoing unprecedented change in the transition to a low carbon system. Technical, environmental, political and economic factors are driving changes in the way energy is produced – with a greater emphasis on renewables production such as solar photovoltaic (“PV”) and wind generation, and an increasingly limited role for traditional methods of generation that utilise fossil fuels. Equally, customers’ needs are also evolving with the roll out of smart meters, increasing digitisation and the potential large scale transition away from the internal combustion engine to electric vehicles. Furthermore, technological developments in batteries and other storage assets mean electricity may increasingly be stored in greater volumes (and more cheaply) than has historically been possible.

1.2 In light of these changes, it is unsurprising that the role of electricity transmission – the network of high voltage electricity cables that enables electricity to be conveyed from producers to consumers – will also need to evolve. In today’s world, the transmission networks (and non-network solutions, where appropriate) need to be developed in a way that enables electricity to be supplied reliably and cost-efficiently despite the complex challenges raised by greater intermittency and reduced inertia of wind and solar generation, increasing penetration of distributed generation, and greater consumer engagement with the market (e.g. as enabled through smart metering and demand-side response).

1.3 Recognising the challenges facing the National Electricity Market ("NEM") of Australia,[5] a panel led by Dr Alan Finkel was tasked to provide an independent review of the Australian electricity market and to advise on the blueprint for coordinated national reform (the "Finkel Review") to provide an overall assessment of its current energy security and reliability, and to provide advice to governments on a blueprint for coordinated national reform.[6] This review provided two main recommendations for transmission planning:

- A long-term, integrated plan for the grid that establishes the optimal transmission network design to enable connection of renewable energy resources, including through inter-regional connections; and
- Improved coordination of generation and transmission planning and investment.

1.4 In response to the recommendations of the Finkel Review, the Australian Energy Market Operator ("AEMO") has published an inaugural Integrated System Plan ("ISP") for the NEM, which is designed to provide an integrated view of transmission investment requirements of the NEM over the next twenty years.[7]

1.5 In this context, AEMO has commissioned the energy teams of FTI Consulting LLP ("FTI") and its subsidiary company Compass Lexecon (together "FTI-CL Energy") to prepare a report on current international transmission planning practice, and identify lessons for AEMO and options for effective future model(s) for the NEM. As part of this work, AEMO has asked FTI-CL Energy to prepare a report on current international practice of the process for deciding upon and agreeing investments in new transmission capacity and to identify areas where practices in the NEM differ from wider international precedent.

1.6 This report focuses on the various ways in which jurisdictions consider the case for an investment in transmission – which we refer to as an investment test. The entire transmission planning arrangements and the associated wider issues, such as the role of different parties in the decision-making and approval processes and the way in which costs and benefits are allocated, are considered in a separate FTI-CL Energy report.

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5 The NEM includes five price regions corresponding to five states: Queensland, South Australia, Tasmania, Victoria and New South Wales (including the Australian Capital Territory).

6 Dr. Alan Finkel (2017), 'Independent Review into the Future Security of the National Electricity Market'.

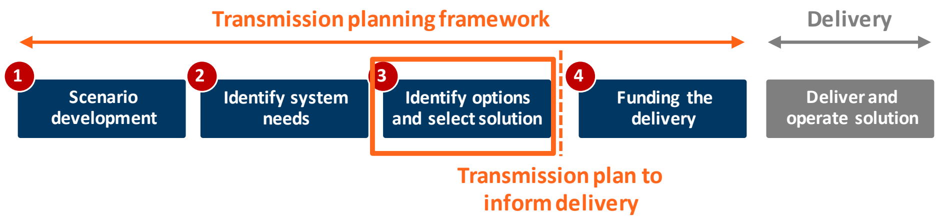
7 AEMO (July 2018) Integrated System Plan.

1.7 Investment tests for transmission assets have been adopted in many jurisdictions to evaluate the merits or otherwise of proposed network investments. In a typical project lifecycle for a transmission asset, an investment test serves to:

- articulate and coordinate different options for resolving a particular system need (e.g. through new transmission investments or non-network solutions such as demand side response or active network management);
- identify and compare solution(s); and
- if required, select the preferred solution (in either an advisory or obligatory capacity).

1.8 The process of an investment in a transmission asset (or group of assets) tends to follow a very similar lifecycle in every jurisdiction. It commences with the identification of the need for a new asset and ends with the operation of the new asset. This is summarised in Figure 1-1 and described in more detail below.

Figure 1-1: Role of investment tests in a typical project lifecycle



Source: FTI-CL Energy analysis.
Note: Although they are ordered sequentially, for ease of exposition, some activities may in fact occur concurrently,[8] *be undertaken repeatedly,*[9] *or may not occur at all for some types of projects.*

1.9 The first stage, scenario development, serves to articulate the range of long-term market pathways in terms of power demand (e.g. driven by GDP and other macroeconomic variables, as well as energy efficiency) and its balance relative to power supply (e.g. closures of existing plants and new builds, driven by factors such as commodity prices and decarbonisation agenda).

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8 For example, the different design variants of a project might affect the assessment undertaken in identifying and selecting the solution.

9 For example, changes to the project requirements may require that some of the activities are partially repeated before the final asset is delivered.

1.10 In the second stage, identification of system needs, a relevant authority performs an assessment of the future transmission network system needs. Depending on the jurisdiction, this assessment may be based on a particular category of need, such as economic benefit of reduced congestion costs, public policy or reliability need to address potential violations of relevant reliability criteria.

1.11 The third stage is where the investment test plays a critical role: for a given system need, the investment test is a tool used by the relevant authority to select a solution to meet that need, often on the basis of a cost-benefit analysis.

1.12 In the fourth and fifth stages, the selected solution is delivered, and subsequently operated, by an authorised party (e.g. a Transmission Operator ("TO") or, in some cases, a non-TO party).

1.13 This report has the following sections:

- **Section 2** describes the evolving nature of power systems around the world and the role and design of investment tests for transmission networks in meeting the evolving need for transmission investments;
- **Section 3** summarises the international experience of investment tests for transmission networks, highlighting common best practice, and areas where investment tests have successfully addressed the evolving nature of the power system;
- **Section 4** provides an overview of the RIT-T as used in the NEM and identifies any differences relative to international best practice; and
- **Section 5** summarises the findings and lessons learnt.

1.14 This report also includes two appendices:

- **Appendix 1**, which sets out selected examples of transmission network investments in the US and Europe; and
- **Appendix 2,** which sets out a more detailed assessment of the international case studies for investment tests for transmission networks.

2. Role and design of investment tests for transmission networks

2.1 Transmission networks provide the crucial infrastructure for transporting electricity from an entry point where it is generated (or injected from another network), to an offtake point where it is consumed (or distributed onto another network). As electricity systems have developed, transmission networks have played a critical role in ensuring both the reliability of a system's electricity supply – by ensuring electricity can be conveyed to where it is required at all times - and overall affordability to society – by enabling the delivery of electricity from lower cost sources of production to the centres of load.

2.2 Throughout the 20th Century, growth in electricity demand tended to be directly related to general economic activity and tended to grow in line with economic expansion. The prevailing technologies at the time meant this increasing demand for electricity was historically met at lowest cost through the development of new very large power stations (typically using a mixture of thermal, nuclear or hydro technologies). The role of transmission was to ensure that the increased demand was served by these large power stations.

2.3 Prior to the liberalisation of the energy sector (which many countries went through during the 1980s and 1990s), transmission networks were typically jointly owned with generation, as vertically-integrated entities. This allowed the integrated entities to coordinate both generation and transmission network investments within the boundaries of their respective jurisdictions. Any necessary cost-benefit assessment of specific investments would have been fully internalised by the 'single decision maker' within each of the vertically integrated producers-*cum*-supplier of electricity having an understanding of both parts of the supply chain. In practice, the effectiveness of this coordinated decision making depended on local circumstances.[10]

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[10] See FN1.

2.4 The introduction of competition in electricity generation was motivated by policy makers' desire to drive efficiency in both investment and operation of the generation part of the electricity value chain. To ensure a "level playing field" in the generation market, the liberalisation process was typically accompanied by the vertical unbundling of generation activities from some or all of the transmission activities into separate companies. The precise details of how the unbundling process inevitably varied by jurisdiction – in some systems, the entirety of transmission network asset ownership and system operation activity was unbundled into a separate business whereas in others only the system operation and transmission planning parts of the activity were separated out.[11]

2.5 While the liberalisation process is generally agreed to have been beneficial to consumers,[12] the new ownership structure in the sector introduced a degree of complication in the transmission planning function which now had to coordinate with multiple new parties – notably between the competitive generation sector and the regulated transmission sector – where previously there was a single decision maker across both sectors.

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[11] In GB, a single SO, the National Grid System Operator operates across the whole of the GB transmission network (England, Wales and Scotland). There are three TOs that own and operate the transmission network in their respective regions: National Grid Electricity Transmission in England and Wales, Scottish Power Transmission in southern Scotland, and Scottish Hydro Electric Transmission in northern Scotland and the Scottish islands.

In the US, the electricity network is divided into separate regions in which Independent System Operators ("ISOs") are responsible for the power system reliability, and competitive generation markets and transmission planning, and are independent from the transmission owners and operators.

[12] For example, the IEA finds that "*Electricity market liberalisation has delivered considerable economic benefits. Under pressure from competition, assets in the electricity sector are used more efficiently, thereby bringing real, long-term benefits to consumers.*" IEA (2005) Lessons from Liberalised Electricity Markets, pp 14.

2.6 In addition to coordinating multiple participants across the sector when deciding on transmission investment, a new challenge has emerged as a result of new drivers of transmission investment. While the transmission investment of the past was driven mainly by the twin factors of security and affordability, concerns over climate change have meant a third factor – that of sustainability – has now also become a critical factor in driving transmission investment. In particular, instead of being driven primarily to meet perpetually growing demand, transmission is now increasingly driven by the need to address:

- **Renewables deployment.** Transmission is increasingly required to connect more diverse sources of generation, such as wind and solar generation that have different, and intermittent, output compared to traditional sources of generation. Some renewables may have limited discretion over their most efficient siting which means that new transmission assets may need to be connected across greater distances at higher costs,[13] or may even face opposition from certain stakeholders.[14] Also, some renewables generation is increasingly being installed at a local level and embedded in local distribution networks.
- **Changing demand and supply fundamentals.** The slowing demand growth[15] and the expected retirement of large thermal generators will affect how transmission networks are utilised to facilitate the flow of electricity from generators to consumers. To meet the evolving system needs, a fundamental "reconfiguration" of the network might be required, which in turn, would affect how future generation and transmission investments and planned and delivered.

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13 For example, solar irradiation, onshore wind speeds, or the depth of seabed are factors generators cannot influence and yet these factors often determine the economically and technically feasible locations for new renewable generation assets. For example, onshore wind development in Scotland (with relatively limited local demand) is leading to investment in transmission networks between Scotland and England to enable the wind output to be transported towards the high-demand zones.

14 For example, the location of new onshore windfarms is often subject to local opposition due to the turbines' visual impact. Similarly, offshore windfarms may be subject to strong opposition by interest groups – in GB, the Royal Society for the Protection of Birds has been involved in a long-standing legal challenge against Scottish offshore wind farms.

15 Driven, for example, by improvements in energy efficiency and distributed energy resources.

2.7 The renewables deployment in particular has increased the need for coordination among multiple parties across the regulated transmission and merchant generation parts of the market. The introduction of Renewable Energy Zones ("REZs"), proposed by the Finkel review, is a recent example of an attempt by policy makers to overcome these coordination issues.[16]

2.8 To manage the increasingly complex system and to coordinate multiple parties, policy-makers, regulators and governments have typically designed a transmission planning framework. This might, initially at least, have represented an updating of (or an extension to) the planning framework that had existed within the vertically integrated business – albeit to take account of the new number of players, their incentives and more diffuse information sources. Such a framework typically serves to determine the key roles and responsibilities of different parties, the economic or technical principles against which a proposed investment should be assessed[17] and the principles for deciding how costs and benefits might be allocated amongst various parties.

2.9 The investment tests have been developed as part of this process, to serve as a tool to support the transmission planning process. In particular, the investment tests serve to improve the coordination among participants by providing a structured and objective manner in which different investment options could be compared, assessed and prioritised to meet the policy makers' overarching objectives.

2.10 This remainder of this section sets out the high-level design of investment tests. We describe in turn:

- the approach to meeting transmission needs;
- the methodology of investment tests;
- the process and application of the investment tests; and
- how investment tests might address potential market failures.

16 Competitive Renewable Energy Zones have been developed, for example in Texas, as a tool to help coordinate wind developers and transmission networks development.

17 For example, in the NYISO, the system operator evaluates both the technical viability and the cost-efficiency of potential transmission investments.

A. Meeting transmission needs

2.11 As described above, investment tests typically serve to evaluate a range of potential network solutions to assess whether they effectively meet a system need in a way that is likely to be beneficial to society as a whole or, in some approaches to the investment test, a subset of society – such as electricity consumers. These tests are usually undertaken through a form of Cost Benefit Analysis ("CBA"), where the costs and benefits are estimated for each potential solution under a range of different scenarios.

2.12 Investment tests typically evaluate the net benefits for each solution under individual scenarios and may be required to recommend a particular solution to be taken forward into the design phase.

2.13 The scenarios used to support investment tests tend to describe different pathways for the future evolution of the system and they typically include:

- **Demand projections**, both in terms of total demand and peak demand, for the relevant region(s);
- **Supply projections**, in terms of the future generation mix (including new build as well as existing plant closures or mothballing assumptions); and
- **Input assumptions** such as fuel and carbon prices, as well as wider economic and policy factors such as renewable subsidies.

2.14 Different jurisdictions often have distinct approaches to scenario analysis. For example, the approach to developing the scenarios in GB and the US is set out in Box 2-1 below.

Box 2-1: Development of scenarios in GB and in the US

In GB, the SO (National Grid) annually produces a set of "Future Energy Scenarios" ("FES"), which are widely regarded as relevant benchmarks for assessing future outcomes in the energy market. In 2018, FES set out four different scenarios, or states of the world, that represent different combinations of decentralisation (extent to which assets are linked to local networks and processes) and decarbonisation (carbon emissions reduction and increasing sustainability).[18]

The US does not have a centrally determined set of scenarios equivalent to GB's FES. Instead, each SO (known as ISOs in the US)[19] performs their own individual forecasts and studies to estimate future energy outcomes:

- For example, the New York Independent System Operator ("NYISO") Gold Book contains baseline forecasts of NYISO load and capacity data for the next 10 years. Subsequent studies may then adjust these baseline forecasts according to specific scenarios for the purposes of its biennial (once every 2 years) transmission planning process.
- PJM also publishes baseline forecasts as part of its transmission plans. However, PJM also has an option (unlike NYISO) to include additional scenarios that adjust baseline forecasts (i.e. in addition to the standard baseline ones). For example, in 2015, PJM examined three additional scenarios, which explored the effects of higher winter load, the retirement of specific plants, and an environmental policy requirement. However, in PJM's 2017 transmission plan, no specific scenarios were examined to adjust its existing baseline forecasts.

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18 National Grid, FES 2018.

19 In the US, SOs are referred to as Independent System Operators ("ISOs"). This denotes the SOs' independence from TOs and other market participants in performing their roles as the central transmission planners and system balancers. This contrasts with National Grid's dual role in GB as both SO and TO. In England and Wales, the SO and TO are vertically-integrated but are functionally separated (and are due to be legally separated in 2019). In Scotland, National Grid is an independent SO as there are two independent and separate TOs. The independence of the US ISOs is akin to AEMO's current role in the NEM (except for in Victoria where it is also the TNSP).

2.15 Against the background of different future market scenarios (which may be determined differently across individual jurisdictions, as illustrated in Box 2-1), the transmission planning process typically identifies the likely future system needs. The investment test can then be applied to select a solution to meet these needs. Relevant system needs could be, for example:[20]

- **Network deepening**: this refers to transmission investments that do not necessarily have clear market benefits[21] and "*involve physical upgrades of the facilities on the incumbent's existing network … physically intertwined with the incumbent TO's facilities*".[22] In the Australian context, this is referred to as a 'reliability corrective action'; and
- **Network expansion**: this refers to transmission investments that "*involve the construction of separate new links (including parallel links) that are not physically intertwined with the incumbent network except at the point at either end where they are interconnected".*[23]

2.16 Network expansion system needs can drive investments that take place within a zone where there are no wholesale electricity price differentials (i.e. 'intra-state' investments in the NEM context). Alternatively, these needs can drive investments between price zones where there are wholesale electricity price differentials (i.e. 'inter-state' investments in the NEM context). Three key examples of network expansion investments are:

- **Standard AC transmission lines**: these are transmission lines that connect two separate areas (e.g. face considerable congestion constraints) within a price zone;[24]

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20 This categorisation is based on the physical attributes of the transmission investment. Other jurisdictions follow different definitions, for example the US evaluate the ability for an investment to improve reliability, reduce congestion costs (economic efficiency), or enable public policy objectives.

21 Note that system upgrades that reduce the possibility of electricity outages will have market impacts.

22 Joskow and Tirole (2005) Merchant Transmission Investment.

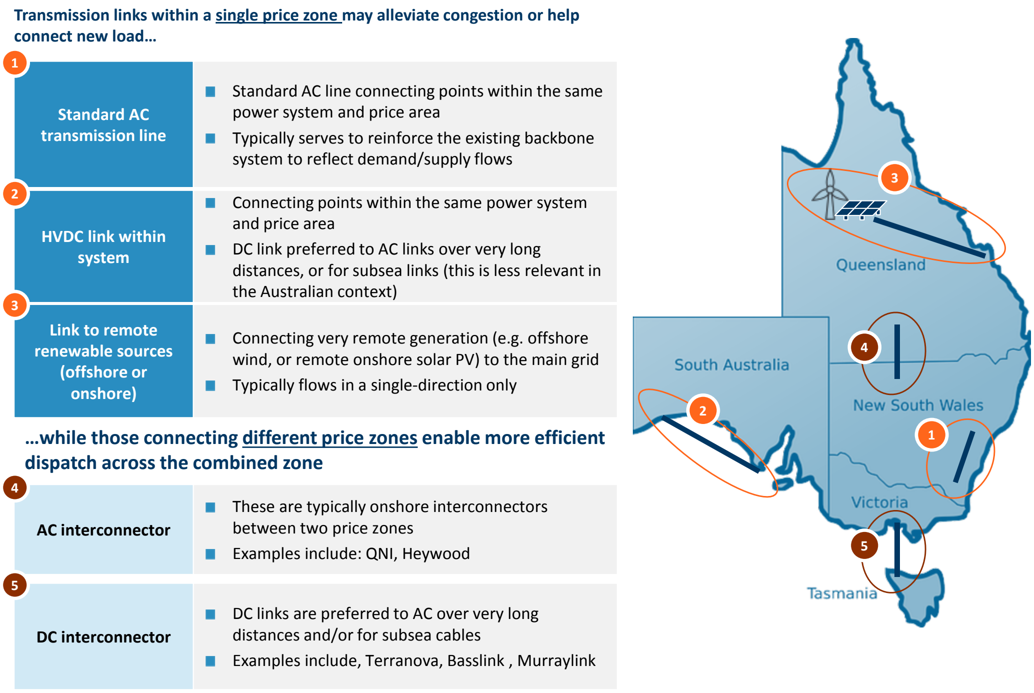
23 Ibid.

24 In the US, nodal pricing (as opposed to zonal pricing used in Australia) means that onshore transmission networks connect two different price nodes and are therefore more akin to interconnectors.

- **Interconnectors**: these are transmission lines that connect two different price zones and their construction allows the arbitrage of differences in wholesale prices of the two zones; and
- **Connection to a new large generator asset (e.g. renewable zone)**: this refers to transmission investments that connect from the incumbent network to new large generation assets. These have been used to connect to offshore wind farms in a European context but might also be used in the NEM to connect to onshore 'renewable zones'.

2.17 Figure 2-1, below, illustrates some different circumstances in which transmission assets may be developed to meet identified transmission system needs, in the context of the NEM as a highly stylised example.

Figure 2-1: Five broad types of transmission assets[25]



25 Moreover, increasing trends in the development of renewables and interconnectors have led to greater consideration (although no realisation as yet) of "energy islands" which would combine different types of transmission assets, for example type 3 (links to remote renewables) and type 4 (AC interconnector). One example of a proposed development is an artificial island at Dogger Bank in the North Sea in Europe (https://www.tennet.eu/our-key-tasks/innovations/north-sea-wind-power-hub/).

Source: FTI-CL Energy analysis.

2.18 As Figure 2-1 above indicates, one key differentiator between types of transmission investment is that they can be constructed either:[26]

- between different price zones ("inter-zonal") – for example between NSW and Queensland – known as interconnectors. These correspond to asset types 4 and 5 in Figure 2-1 above; or
- within the same price zones ("intra-zonal"), which correspond to asset types 1, 2 and 3 in Figure 2-1 above.

2.19 The different network context (or system 'need') in which transmission assets are developed therefore lead to different benefits. This can be illustrated by comparing the revenues that may or may not be earned by inter- and intra-zonal transmission assets.

2.20 First, assets that connect different price zones (asset types 4 and 5 in Figure 2-1 above) enable the transmission owners to export electricity from the low price zone to the high price zone. In doing so, the transmission asset generates an arbitrage profit – known as the congestion rent. Allocation of this rent, resulting from by an inter-zonal investment among market participants, may vary as follows:

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[26] This distinction is less relevant in electricity systems with locational marginal pricing on a nodal basis. This means that a spot price is set by the market for each node (a substation or switchyard where multiple transmission lines intersect) at each point in time. The transmission price of using the network between two nodes would therefore reflect the marginal price (including congestion and losses) and hence could typically be used to determine the net economic benefit of further transmission network investments.

- **Merchant.** The developer of a cable retains the congestion revenue over the asset's lifetime and uses it to fund the cost of the development and construction of the asset. This, in essence, is the merchant model of transmission;[27]
- **Regulated.** Alternatively, the asset can be developed as a regulated, rather than merchant, investment. In this case the congestion revenues are subject to a revenue control mechanism. In this case any shortfalls in congestion revenues are recovered from grid users and, conversely, any extra congestion revenues are returned to grid users; and
- **Hybrid.** 'Blended' approaches that combine regulated and merchant features, such as the Cap and Floor regime in GB, are also possible.

2.21 Second, assets that connect two points within a single price zone (e.g. the first two transmission network asset types in Figure 2-1) cannot earn congestion rent – for the simple reason that there is no price differential to arbitrage. Hence, such assets can only be funded under some form of regulation and the costs recovered through a fee levied on users of the network.[28]

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27 A large volume of academic research has been dedicated to the consideration of whether merchant transmission investments can deliver a socially optimum volume of transmission. Theoretical models show that under a set of relatively strict conditions all investments that are profitable for the investor in new transmission capacity are efficient (e.g. Joskow and Tirole (2005), pp 241). However, research has also shown that these conditions are not always met in practice, and that in many cases there tends to be an under-investment in merchant interconnector compared to the social optimum. More recent research therefore found that "*efficient investment may need regulatory mandates and a regulatory cost allocation*" (Hogan (January 2018) A Primer on Transmission Benefits and Cost Allocation).

28 Costs of assets that are developed within a single price zone (and in the absence of locational marginal pricing) cannot, by definition, be recovered through merchant revenues. Instead, these investments are typically undertaken by incumbent TOs and costs recovered through regulated revenues (although third-parties may also own and operate these assets).

2.22 Investment in transmission assets within a single price zone is driven primarily by the need to resolve intra-zonal congestion, but also by service quality, regulatory requirements and/or connections to new load.[29]

2.23 In addition, in the NEM, intra-regional transmission investments could remove a congestion constraint in order to:

- allow previously constrained off generators to generate more frequently; and
- in turn, lead to reductions in the electricity price (at the regional reference node) in that zone, at certain points in time, by enabling a lower marginal cost generator to produce.

2.24 In GB, the benefits of reduced congestion may include reduced compensation payments. This is because the GB approach to resolving congestion is different from the NEM. In GB, the market first clears "as if" there were no congestion constraints (a 'first best' outcome). The SO then clears the market with the system constraints taken into account, which typically leads to some generators being constrained 'on' and others 'off'. Both of these generators are compensated for their costs relative to the 'first best' outcome.[30]

2.25 Third, connection of remote renewable generation (Type 3 in Figure 2-1) can be seen as a standalone driver of investment, motivated by the resource availability for low-carbon generation. As set out in ¶2.6, some types of generators in some jurisdictions have limited discretion over their siting decisions, which may in turn, drive the need for specific transmission investments.

[29] In Australia, the AEMC and the Reliability Panel set the relevant guidelines and standards for the power network reliability. These may relate for example to the frequency operating standard and wider security and safety rules. Source: AEMC – Developing electricity guidelines and standards, accessed at: https://www.aemc.gov.au/our-work/developing-electricity-guidelines-and-standards.

[30] The US approach is fundamentally different due to the use of locational pricing, which means that the SO is able to clear the market without any separate compensation for congestion (which is directly priced into the LMPs).

2.26 As set out in ¶2.20, transmission assets between price zones can in principle be merchant, regulated, or hybrid. In practice, investments in merchant transmission assets have been highly challenging. The changing nature of the power system has created complexity and risks that have largely limited merchant development of transmission assets, as few investors appear to be willing to take on the market risks without some form of regulatory support. Merchant approach only appears to be feasible in the most favourable cases where:

- identifiable inter-zonal congestion rents can be allocated to the prospective developer (e.g. HVDC interconnectors between two different countries, say France and GB);
- where the intrinsic value of the interconnector is sufficiently high and robust against a wide range of future scenarios;[31] and
- where the issue of coordination between multiple parties (such as independent countries / jurisdictions) is successfully resolved.

2.27 Therefore, even though merchant solutions may be an attractive transmission investment option in specific circumstances, the majority of transmission assets are regulated – this includes intra-zonal assets, inter-zonal interconnectors as well as links to new renewables.

B. Methodology of investment tests

2.28 Investment tests for transmission assets typically compare the expected costs of the assets relative to the benefits over a set period of time under a given range of scenarios (described in the previous section). The duration over which the benefits are assessed might be assumed as the technical life of the asset or a shorter period of time. In either case a discount rate is applied to identify the net present value of the benefits relative to the costs.

31 For example, IFA and BritNed are two interconnectors between GB and continental Europe that have been operating on a merchant basis (IFA since 1986 and BritNed since 2011). More recently, two new merchant interconnectors, Aquind and ElecLink, are being developed between France and GB. It is important to note that their development has to be sanctioned by the regulatory authorities at both ends of the links, notably in relation to specific exemptions from European electricity codes. The requirement for merchant interconnectors to obtain an exemption from the regulatory authorities is in itself a significant regulatory risk and potentially acted as a deterrent from investment in merchant interconnectors in Europe.

2.29 In general, a CBA aims to assess whether proposed transmission investments have a present value of future benefits (which are uncertain due to imperfect foresight, and therefore estimated based on assumptions and probability-weighted scenarios) that sufficiently exceeds the present value of expected costs of the investment (which is typically relatively more certain). To consider the various scenarios, a CBA can use different methods to select the preferred option, for example:

- which may be the highest net present value of the net benefits (i.e. benefits minus costs);
- least-worst regret (i.e. selecting the option that has the highest net benefits in the worst downside scenario); or
- or simply least-cost (e.g. the lowest-cost solution that achieves network compliance with a specific reliability requirement which has no quantifiable market benefits).

2.30 The range of costs assessed as part of a transmission investment test tends to be similar across jurisdictions. Costs include design and construction costs, operating and maintenance costs, tax and other non-controllable costs, and financing costs.

2.31 Because of the long lifetime of the asset, the benefits of a transmission investment are harder to quantify. Within a given price zone, the benefits typically include the reduction in congestion costs. As noted earlier, this will manifest through a combination of reduced SO cost and/or reduced wholesale electricity prices, depending on the approach adopted for congestion resolution.

2.32 An inter-zonal investment such as an interconnector will typically impact a range of different stakeholders: it will benefit consumers in the importing region (through lower prices paid), generators in the exporting region (through higher prices received), and the new transmission owner (through congestion revenues), while existing transmission owners may be negatively impacted (through lower congestion revenues).[32]

[32] This is explored in more detail in ¶2.60 *et seq*.

2.33 All three components listed above are often taken into account when assessing the total (or 'social') welfare impact of inter-zonal transmission investment. In addition, in some cases, the distributional impact of the new transmission asset may also be taken into account).[33]

2.34 Externalities that might arise from a transmission investment – such as increase in economic activity on account of access to lower costs of electricity in a particular location[34] – are not usually considered quantitatively in either the costs or benefits when assessing transmission investments due to the difficulty in calculating them. However, they may be considered qualitatively to form a holistic view on the proposed investment (e.g. Ofgem in assessing Strategic Wider Works with network companies). In addition, the strategic value of transmission investment (e.g. to achieve greater harmonisation between energy markets in multiple regions, or to facilitate anticipated renewables generation) could be considered.

2.35 To calculate the net benefits, a discount rate is applied. There is no consensus on the appropriate approach and quantum for the discount rate. Possible options include a 'social discount rate', different discount rates on a case-by-case basis and a comparable private sector discount rate among others.[35] For competitive tenders, bidders may be able to select their own discount rate to reflect their risk profile and financing structure.

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33 In GB, the distributional impact of interconnectors is taken into account by the regulator, who assesses the costs and benefits of a particular project from the perspective of GB consumers only. The different approaches to considering consumer surplus, producer surplus and congestion rent as part of investment tests are explored below in ¶2.36.

34 Externalities may relate, for example, to the impact of the development of a transmission asset on the local economy (e.g. catering, housing), or to the price change impact in a particular zone (e.g. the construction of an interconnector may reduce the energy costs in a zone, which may in turn increase the competitiveness of energy-intensive industries relative to other regions).

35 The social discount rate aims to capture the time value to society of costs and benefits. It is the rate at which society values the present compared to the future, and considers the time preference of consumption and the wealth effect of expected growth in per capital consumption. In the UK, it is labelled as the HM Treasury Social Time Preference Rate ("STPR"), and has been set at 3.5% in real terms since 2003.

2.36 The investment criteria for a CBA consider the net present value of the net benefits over a predefined period. This depends on the range of scenarios tested against over the predefined period. As a transmission investment might produce winners and losers, a key factor for the investment criteria is whether the investment test should measure the net benefits from a consumer perspective or a social perspective (including the impact on generators). Additionally, for investments across two different price areas, there needs to be consideration on which price area to include in the CBA,[36] and an evaluation of the congestion rent.

C. Process and application of the investment tests

2.37 Investment tests are typically undertaken by either the SO, the incumbent TO, or the regulator (or a mixture of the three), or, in some cases, the Government. The choice of who is best placed to take on the role tends to depend on a combination of:

- historical context;
- the availability of information and resources; and
- policy decisions.

2.38 Investment tests typically allow for third-party involvement. This includes potential third-party owner/operators, developers of new generators or incumbent or neighbouring TOs.

2.39 As transmission investments typically require a long lead-time, the timeframe of investment tests are an important design parameter and, in particular, the frequency of any investment tests (i.e. at what stages / how often a proponent can initiate a new investment test) and the duration of such tests (i.e. how long it may take from the initial proposal to the final approval of the test by the relevant authority).

[36] For example, where two different countries are to be connected, each of them is likely to primarily consider the impact only on their own country, rather than the combined social welfare impact that includes both countries (although, in Europe, ENTSO-E also considers the impact on of an investment on neighbouring countries). This is different from investments that connect different price zones within the same country (as is the case in Australia).

2.40 Finally, the process of the investment tests often allows for a set-up of a disputes resolution process (which may in turn impact on the timelines of the investment test). While policy makers do not intend for investment tests to lead to this outcome, it is a fall-back mechanism through which any disagreements on the CBA (or other matters) may be resolved.

2.41 In this report, we comment on the process and roles of the SO, TO and the regulator in running the investment tests. In a separate FTI-CL Energy report we discuss the wider role of these three entities in the broader transmission planning process.

D. Addressing prevailing market failures

2.42 As discussed above, investment tests are complex due to the inherent size and uncertainty of transmission investments, the difficulty in coordinating information, the long asset lifetimes (often in excess of 40 years) and the inherent difficulty of assessing the future benefits (the duration and allocation of which is highly uncertain) against the costs (which are 'lumpy' but relatively more certain and more 'immediate').

2.43 This complexity of transmission investment, and the associated challenges in designing an appropriate investment test, arise from four key issues :

- information asymmetry among different market participants;
- imperfect information (e.g. uncertainty regarding the future);
- coordination failure among market participants; and
- misallocation of risk and rewards.

2.44 We discuss each in turn in the following subsections.

Information asymmetry

2.45 Information asymmetry refers to the different set of information available to different parties that are not necessarily readily disclosed to the party undertaking the investment test (or to third-parties independently evaluating possible generation or transmission investments). This increases the risk of inefficient decisions being made. Information asymmetry could arise from various sources including:

- TOs tend to have private and superior information about their own network compared to all other parties in the market. As a result, policy makers may have a concern that, while the TO is best placed to know the impact of alternative investments on its network or on connecting networks, it is also potentially best placed to exploit its information advantage.[37] Regulatory regimes continually grapple with the design of a regime that overcomes the information asymmetry through a combination of information disclosure rules (the 'mandatory' approach) and incentives to reveal private information (the 'incentive' approach).
- Third-party prospective developers of transmission assets have considerably less knowledge about the existing network, constraints and future demand compared to the incumbent TOs, and may be at a disadvantage. However, third-party developers may not always propose solutions that are optimal from a social welfare perspective. For example, there privately developed merchant interconnectors may not always lead to socially optimal investment (see FN27). As a result, it is appropriate for the relevant authority to evaluate the welfare impacts of any prospective merchant transmission assets before allowing them to be developed.
- There is also a further information asymmetry in regard to what generation will be shut down or started up within the planning horizon for the transmission investment. As generators are typically undertaken as merchant investments, they can be built and decommissioned[38] at any time, making it difficult for a transmission planner to set a long-term view. As a result, given the partial (and imperfect) substitutability of generation and transmission investments in certain conditions, an unexpected entry and exit of generating capacity could materially affect the existing operation of the network and the future need for transmission investments.

2.46 There is a potential risk of further information asymmetry if the transmission investment would affect the distribution network and vice versa.

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37 The actual potential for leveraging any information advantage would depend on a number of factors including, *inter alia*, the ownership of the TOs and the way in which they are regulated and incentivised to use and disclose their information.

38 The NEM is considering introducing rules on the minimum 'notice' period that generators must give prior to closing, which would limit the discretion generators have in decommissioning their assets.

2.47 Hence, often the role of the regulator is, *inter alia*, to extract as much information as possible from the TOs and third-parties and, in doing so, to minimise the risk of inefficient investments being undertaken. The inefficiency could result either from 'too much' investment being undertaken (resulting in network redundancy or excessive costs), or 'too little' investment – which could in turn increase the cost of congestion on the network (in excess of the cost of the foregone transmission investment) ultimately paid for by the consumers.

2.48 The regulator can discharge this role in two ways:

- Direct involvement in the investment test; or
- Through a 'design and administer' approach, such as used by the AER, whereby the regulator simply sets the rules, but does not get directly involved in the running of the test.

Imperfect information

2.49 Imperfect information refers to the lack of available information when carrying out an investment test. In particular, there is uncertainty as to whether the future benefits of the investment outweigh the costs, which in turn makes it challenging for investment tests to evaluate transmission solutions. This is because of:

- **Uncertain costs.** First, the large-scale nature of transmission assets requires significant investment costs and the associated cost recovery after they are built. Evaluation of the need for the project, alternative solutions and cost recovery needs to be coordinated with a number of other parties (e.g. generation, distribution, and third-party developers) and against a highly uncertain future need for the asset. Transmission asset investments may involve challenging planning and consenting processes due to their size and local impacts, and they also tend to be complex from an engineering point of view, which may have follow-on effects with the existing networks.
- **Uncertain benefits.** Second, future benefits of potential transmission investments are even more uncertain than the costs. In particular, there is significant uncertainty regarding the future demand and supply scenarios (which in turn are used to identify the system need) and the monetary benefits of the investment. The fast-evolving nature of the energy market, in conjunction with the long lead-time of transmission investments mean that estimating future benefits is difficult.

2.50 A further complication is that, in many cases, transmission assets allow cheaper, but more distant, generation to displace local, but higher cost generation. This in turn impacts the prices received by generators, and paid by consumers, and also creates the potential for winners and losers to arise from a specific transmission investment. In turn, this creates an incentive for different stakeholders in the system to advocate for different approaches to transmission.

2.51 Therefore, the design of investment tests typically involves:

- collecting information from multiple parties in the electricity supply chain (e.g. generators and transmission operators) in order to reduce the information uncertainty;[39]
- developing a reliable view on long-term scenarios and the identification of the investment need;[40]
- guidance or requirements imposed on the input assumptions that should be relied on in the CBA (including discounting assumptions); and
- the methodology used for the evaluation of the impact of the transmission investment, particularly on reliability and prices.

2.52 While the design and use of scenarios are intended to identify the range of future uncertainties regarding the need for future transmission investments, the issues related to imperfect information are likely to become even more challenging over time. This is due to the uncertain supply-side developments such as generation deployment (volume and location), rate of penetration of renewables (leading to a need for greater system flexibility in dispatch in order to manage rapid changes in net load) and increasing energy decentralisation. Similarly, growing demand side developments such as load growth (e.g. from the deployment of electric vehicles and the impact of energy efficiency measures) contributes to the overall uncertainty.

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[39] In the US, investment tests are used to provide information to enable market-driven responses in the first instance, and centralised investment if required.

[40] Scenario development includes both the supply side (i.e. the future development of generation assets which may be renewables or conventional), and the demand side (i.e. the consumption profiles and volumes driven by factors such as electric vehicles and energy efficiency measures).

2.53 These trends mean that operating the network would be more challenging with more volatile and unpredictable flows in the network. Nodal pricing helps the system to cope with the changes in a number of US jurisdictions, but in the absence of nodal pricing, the challenges are more complex. For example, the lack of wholesale price signals within individual NEM zones might mean that there could be unpredictable siting decisions of market participants over the long term. Arguably, the NEM market design, notably the absence of 'firm access' for generators, means that generators have an incentive to make their siting decision locationally efficient. In particular, generators would have an incentive to avoid locations where they would be likely to be 'constrained-off'.[41] Alternative approaches can be used to incentivise more efficient siting of new generation within a given price zone – for example in GB the use of transmission charging varies by location.[42]

2.54 As many sources of imperfect information relate to uncertainty over the future,[43] investment tests may sometimes consider the option value of proposed solutions, for example, the value of the options to delay, expand, or cancel the investment when more certain information is revealed.

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41 This incentive is unlikely to deliver a socially optimal outcome, as new generators may not take into account any potential adverse impact on existing generators (i.e. displacing them from the existing merit order, thus 'stranding' some of the existing generation).

42 In GB, transmission tariffs paid by generators tend to be lower in the regions with high and concentrated electricity demand (e.g. South of England) and higher in more remote regions (e.g. Scotland), which is intended to incentivise generators to site in closer proximity to electricity demand.

43 For example, over-sizing a given transmission line that is developed to connect the main grid to a new source of generation may provide an option value to later use the same line to connect additional plants in the region.

Coordination failure

2.55 Coordination failure refers to the tendency to lack coordination between relevant parties. For example, this might involve:

- creating a bias between intra-regional solutions and interconnectors, particularly as it is often more straightforward for TOs to reinforce their own networks rather than coordinate with neighbouring parties;[44]
- a lack of strategic oversight (e.g. to identify additional strategic benefits of coordinated interconnector or renewables development); and
- a greater risk of sub-optimal combined gas and electricity network solutions.[45]

2.56 For example, in the US, the risk of imperfect coordination has been recognised by the Federal Energy Regulatory Commission ("FERC") and is intended to be addressed through FERC 1000 Order which requires neighbouring ISOs to:

- exchange transmission planning data and information at least annually;
- share information on inter-regional investment needs with each other; and
- identify and jointly evaluate potential solutions to those needs.

44 There can be complicated cases where three jurisdictions are involved and benefits to two non-adjacent TOs can only be delivered by a new transmission line through a 'middle' TO. To the extent that the 'middle' TO does not benefit (and in fact may face increased costs), socially optimal investments are very challenging to deliver. In these cases a 'supra-national' viewpoint can be a critical enabler of socially efficient transmission investment. We will elaborate on the role of the 'supra-national' planner in FTI-CL Energy's wider report on transmission planning coordination.

45 For example, there may be a coordination issue between electricity and gas network development. In a typical illustrative example, an investment decision needs to be made regarding the siting of a gas-powered generator. The siting decision would in turn trigger either gas network development (to pipe the gas to the plant located close to the power demand centre), or power network development (where by power plant is sited close to the gas source, and power is transported to the demand centre). By coordinating the timing, location and scale of transmission and generation investments, the overall benefits of the joint solution can be higher than when decisions are reached independently.

Risks and rewards allocation

2.57 The misallocation of risks and rewards refers to the risks stemming from deciding who is best placed to deliver the transmission investment, and how investment costs are recovered. Not all tests assess the distributional impact that a particular investment might have on different parties (for example the RIT-T focuses on the aggregate net benefits). However, in those cases where the investment test does take into account the distributional impact, then a key principle to adhere to is that the costs of an investment should be placed on the party (or parties) that benefits from the investment and that the risks of an investment are allocated to those most incentivised (and therefore best placed) to manage them. This is often referred to as the "beneficiary-pays principle".[46] However, the application of this principle can, in practice, be complex, and some methods have been the subject of dispute.

2.58 Furthermore, the allocation of benefits may be unknown on an *ex-ante* basis, as market developments may evolve significantly between the decision to invest and actual completion of the project.

2.59 For example, a network deepening investment (i.e. investments to retain power quality, frequency or other technical parameters) is often seen as best being managed by the incumbent TO. In this case, third-party developers, to the extent that they would not be able to identify and capture the economic profit resulting from their investment, would not be in a position to undertake this type of investment. However, there may be examples of network deepening investments that are sufficiently identifiable and separable such that a third-party can undertake the development (such as under the proposed competitive regime in onshore transmission in GB, currently planned by Ofgem).

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46 Hogan (January 2018) A Primer on Transmission Benefits and Cost Allocation.

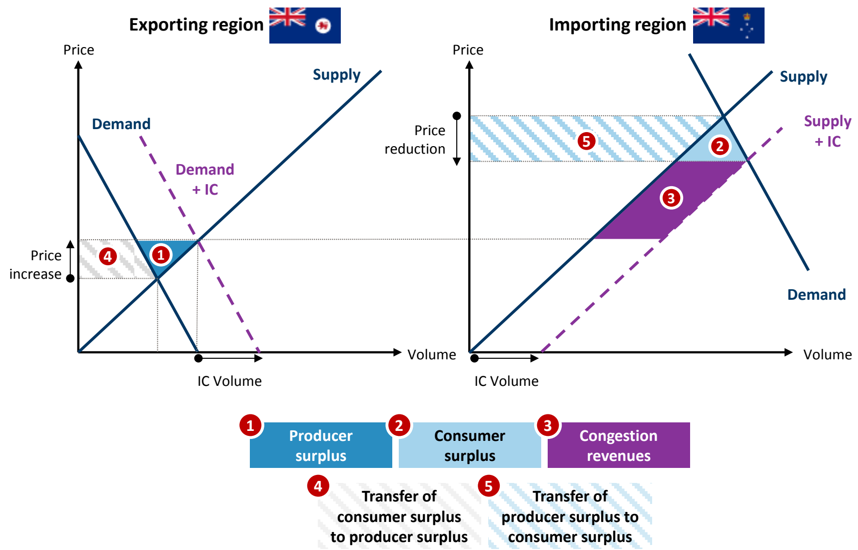
2.60 The complexity of the risk and reward allocation can be illustrated using an example of a network expansion investment, such as an interconnector between two price zones. As illustrated in Figure 2-2 below, the construction of an interconnector has an impact on the producers in the exporting region (through higher prices) and consumers in the importing region (through lower prices). In addition, congestion rent[47] can be captured by the owner of the interconnector.

- Congestion rent (or congestion revenues) is the difference between the prices at which electricity is exported from one point and the prices at which electricity is imported at another point, multiplied by the volume of electricity flow.
- Consumer surplus is the difference between the total value consumers would be willing to pay and the quantum actually paid for electricity (primarily driven by the shape of the demand curve and the electricity prices).
- Producer surplus is the difference between the revenue producers actually receive less the cost of production of electricity (driven by the shape of the supply curve and the electricity prices).

2.61 As shown in Figure 2-2, there are transfers of benefits between producers and consumers that do not increase the net socio-economic welfare. Nevertheless, this might lead to the 'losers' perceiving the outcome as being adverse to them and therefore opposing the socially optimal investment. Likewise, 'winners' might be more supportive of an investment that does not generate overall net welfare benefits (i.e. the losses are higher than the benefits).

[47] A new, privately developed, interconnector tends to consider its own business case on the basis of the congestion rent it expects to earn over the lifetime of the project (as well as any additional revenues, such as from capacity markets and ancillary services), relative to the costs of the project. However, the new interconnector may also lead to an additional price convergence between the two regions, which would in turn reduce the congestion revenues that any pre-existing interconnectors across the two same zones would earn. Similarly, the wholesale price changes in the connecting regions may lead to second-order impacts on interconnectors linking to only one of the two connecting regions. Both of these effects are known as a "cannibalisation effect". From an overall social welfare assessment, this cannibalisation effect can be taken into account by policy makers, but it is not typically taken into account by the privately developed interconnector itself.

Figure 2-2: Cost benefit analysis of an interconnector



Source: FTI-CL Energy analysis.

2.62 The critical question in designing an investment test (and indeed in optimising the volume of transmission investment more generally) is which of the elements in Figure 2-2 should be taken into account (we explore the different approaches to this assessment in Section 3), for example:

- A pure 'economic efficiency' approach would consider the areas 1+2+3 only, i.e. accounting for the net economic welfare impact and ignoring any distributional impacts. This approach often relies on an implicit modelling assumption that the cost curve is a suitable proxy for the price impacts. This approach therefore typically measures the social welfare (i.e. the benefits received by consumers, producers and transmission owners) by considering the changes in the total costs of production.

- A consumer-driven approach in a single jurisdiction might consider only the consumer surplus (and a portion of congestion revenues)[48] i.e. areas 2 + 5 + part of 3. In this case the consumer welfare impact can also be measured by cost changes, but it is also possible to focus on the price changes that consumers are likely to experience as a result of the investment. To the extent that the market prices may depart from marginal costs, the outcomes of this analysis may be different from the production cost approach.
- A partially consumer-focused approach might take into account the net economic welfare (areas 1+2+3, i.e. including the producer surplus and congestion rent), but also attribute greater weight to consumer welfare over producer welfare, by explicitly taking into account the transfers of wealth between the two groups. This could be done by adding areas 5 *minus* 4 to the assessment.

2.63 The regulatory regime to determine the cost recovery mechanism may or may not be part of an investment test. If included, the regulatory regime should address the optimal allocation of costs and benefits between different parties for the transmission investment. The same will apply to any incentive schemes that the transmission asset owner may benefit from.

2.64 As some transmission network investments typically create both 'winners' and 'losers', as shown in Figure 2-2 above, cost allocation mechanisms have a key role in mitigating the negative effects on some parties. In theory, as long as the costs were allocated, proportionately, to the beneficiaries of the investment (and provided the net welfare impact was positive), then all parties could be made better off as a result of such investment. However, as explained in ¶2.58, the practical challenges in identifying and allocating the benefits are significant and often prohibitive (in particular on an *ex-ante* basis).

48 This is the approach relied on by Ofgem when assessing the benefits of a new interconnector under the Cap and Floor regime – see case study in Appendix 1. This approach is only practicable for a jurisdiction that focuses solely on the welfare of its own consumers – i.e. where the two jurisdictions are two different countries. This is not the case for Australia where the connecting regions are part of the same country.

2.65 While the wider issues relating to benefit allocation and cost recovery will be explored as part of FTI-CL Energy's wider report, we note that there are some simplified approaches that seek to partially overcome this challenge. This can involve, for example:

- Using a portion of congestion rent to reduce the transmission charges on parties that are expected to be negatively impacted (i.e. passing through some of the congestion rent earned by the TO to lower transmission charged levied on consumers in the exporting region);[49] or
- Cross-border arrangements between neighbouring TOs aiming to compensate each other for hosting 'transit' flows (the European inter-TSO compensation scheme is an example of this approach being used in practice, see ¶3.41).[50]

2.66 It may also be possible for transmission charges on exports to be reduced in order to mitigate the impact of overall electricity retail prices on 'losers' (although this has not been widely implemented in practice).

49 This approach of cost allocation, while broadly accepted as a useful approach to mitigate negative cost distribution effects, can be complex. The difficulty in predicting flows across the transmission asset over a certain period means that it is difficult to commit to an *ex-ante* reduction in transmission tariffs. One option is to implement an *ex-post* adjustment based on actual flows at various intervals over the life of the asset; however it is unclear if this might result in unintended distortionary incentives. Another option would be to allocate costs on the expectation of the benefits distribution that formed the basis of the investment decision itself (regardless of how the benefits ended up being distributed).

50 In Europe, the traditional roles of the SO and TO are often combined in a single entity, referred to as the Transmission System Operator ("TSO").

3. International experience of investment tests for transmission networks

3.1 This section summarises the international experience of investment tests for transmission networks, and highlights common best practice, if there is any. We have been asked by AEMO to identify potential areas where precedent from other jurisdictions might be helpful to explore further. This section therefore also suggests several areas for further analysis based on the international precedent identified.

3.2 The case studies considered are:

- Great Britain: Strategic Wider Works ("SWW");
- Great Britain: Network Options Assessment ("NOA");
- Great Britain: Interconnectors;[51,52]
- Great Britain: Offshore Transmission Owners ("OFTOs");
- US: NYISO;
- US: PJM;
- Argentina: Public Contest method for major transmission expansions; and
- EU: investments tests for interconnectors.

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51 The GB interconnector case study focuses only on the portion of the interconnector subject to the GB regulatory regime. As a default, this applies only to half of the interconnector, i.e. 50% of the interconnector's revenues and 50% of the interconnector's costs. The remaining half of the interconnector will be subject to the regulatory regime of the other country to which the interconnector is connected. Interconnectors can apply for exemptions to this default (and have more or less of their costs and revenues be subject to the GB regime) via submission to Ofgem, the GB regulator.

52 The case studies evaluated in this report focus on regulated interconnectors. Merchant interconnectors follow a different process.

3.3 In the following sub-sections, we set out the key insights in the test design and implementation from the international case studies, focusing on the approach to meeting transmission needs (Section A), methodology of investment tests (Section B), Process and application of the investment tests (Section C), and addressing potential market failures (Section D).

3.4 Illustrative examples of specific transmission investments undertaken in Europe and the US are set out in Appendix 1. Further details of the case studies can be found in Appendix 2.

A. Meeting transmission needs

3.5 Jurisdictions in GB and the US tend to apply different tests for different asset types. In GB, investment tests have evolved so that different asset types such as onshore assets, interconnectors, and transmission assets to connect offshore wind farms are considered under slightly different approaches. In the US, different investment tests are designed for the varying needs of transmission assets, such as from an economic, reliability or public policy perspective.

Great Britain

3.6 In GB, investment in onshore networks is treated separately from offshore networks and interconnectors.

3.7 As explained in FN11, there is a single system operator in GB, the National Grid System Operator, and three TOs that own and operate the transmission network in their respective regions: National Grid Electricity Transmission in England and Wales,[53] Scottish Power Transmission in southern Scotland, and Scottish Hydro Electric Transmission in northern Scotland and the Scottish islands. A single body, Ofgem, regulates the electricity system in GB.

3.8 For onshore networks, we have examined the investment tests in the SWW and NOA processes which are separate, but linked processes, as explained in the following paragraphs.

[53] While both the SO and the England and Wales TO operate as 'National Grid', they are due to become legally separate entities.

3.9 The **SWW** process allows TOs to put forward proposals for large transmission investments that were not previously planned for in the current price control period.[54] This mechanism exists to account for uncertainty in transmission needs at the time of a price control determination. This process is overseen by Ofgem and, once approved, the investment is included in the remuneration to the TO through the regulatory asset base ("RAB"). The SWW process is therefore run on an 'as-needed' basis, as a complement to the regular price control process. Moreover, the SWW process is run for specific investments, that is to say, a TO makes an SWW submission only if it believes there is a transmission need between two specific points on the GB system.

3.10 The **NOA** is an annual advisory tool, developed by the SO, to recommend transmission investments across GB at specific internal transmission boundaries, and is therefore not limited to recommending a specific investment need between two particular areas. The output of the NOA is a proposed list of projects that address identified needs. The annual NOA publication lists the proposed route and capacity of each project, as well as a status update (e.g. whether a project should proceed, be delayed, not proceed, or if no decision is required in the current year) and the transmission boundaries affected.[55]

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54 SWW assets are distinguished from other smaller-scale transmission investments which are known as wider works outputs, which transmission operators propose (and may receive regulatory allowance for) as part of the standard price control process. SWW projects are defined as larger projects (above a certain cost threshold - £50m in northern Scotland, £100m in southern Scotland, and £500m in England and Wales) that face higher uncertainty around the timing and cost, and therefore cannot be identified and/or approved during the standard price control process. SWW projects are 'triggered' when more information has been revealed over the duration of a price control period, whereas wider work outputs are set by Ofgem as part of the regulatory settlement.

55 The NOA's recommendations are reasonably specific. For example, NOA 3 proposes the Caithness to Shetland 600 MW subsea link as a reinforcement option for Scotland and the North of England region. The NOA proposes to "*install a 600 MW HVDC link between the Caithness–Moray HVDC link, via the HVDC switching station at Noss Head in Caithness, and a new substation at Kergord on Shetland to form a three-terminal HVDC scheme*". This project affects the "*radial*" boundary and is at the "*design/development and consenting*" stage. National Grid, Network Options Assessment 2017/18, January 2018.

3.11 While the NOA's recommendations are non-binding, there is a strong connection between the NOA and SWW. A project given a "proceed" recommendation in the NOA is considered by Ofgem as a "potential SWW project",[56] and Ofgem expects TOs to use the NOA alongside their own analysis when making an SWW submission.[57] In this sense, a recommendation via the NOA process makes an SWW application more likely to succeed. Moreover, if a particular transmission project has been approved via the SWW process, it is subsequently removed from the NOA as a possible option (as the project has been 'approved', and is therefore taken as a "given" in the assessment of transmission needs by the NOA).

3.12 Ofgem undertakes separate investment tests for **OFTOs and interconnectors**. For both asset needs and types, Ofgem has developed specific regulatory regimes to facilitate the potential investments:

- OFTOs are the transmission assets that link offshore windfarms to the GB mainland electricity network. These transmission lines are built by the offshore wind generators, then transferred to be owned and operated by the OFTO. Ofgem runs frequent competitive tenders (at the time of writing this report, five rounds have been completed) to identify the lowest cost bidder (that meets all operational and financial requirements) to perform this ownership and operation role. This is known as the 'generator-build' model. In theory, OFTOs have an option to follow an 'OFTO-build' model, in which they also take responsibility for construction of the transmission asset. However, to date this option has not been used.[58]

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56 Ofgem, Strategic Wider Works, accessed at https://www.ofgem.gov.uk/electricity/transmission-networks/critical-investments/strategic-wider-works

57 Ofgem, Guidance on the Strategic Wider Works arrangements in the electricity transmission price control, RIIO-T1m 24 November 2017.

58 Ofgem (March 2018) OFTO Tender Process – Consultation for Future Tender Rounds, pp 2.

- For interconnectors, Ofgem allows potential interconnector developers to apply for regulatory support that sets a cap and a floor on revenues for the proposed interconnector investment. This assessment considers the impact of the interconnector on GB consumer prices (i.e. inclusive of the welfare transfer from producers to consumers). However, this assessment effectively takes into account only 50% of the interconnector revenues (including congestion revenues[59] and any other revenues, such as capacity market and ancillary services, that the interconnector may be able to earn) and none of the consumer or producer surplus impact in the connecting country. This is because Ofgem has no jurisdiction over, or obligation to, the non-GB country that is connected via the interconnector.[60]

3.13 The rationale for using a separate investment test for interconnectors in GB stems from the policy-makers' desire to increase the level of interconnection to GB and to bring in private investment to deliver this. In the regulator's view, the Cap and Floor regime would give "*developers an incentive to identify efficient investment opportunities which are in consumers' interest*" and "*a level of certainty to developers without providing full consumer underwriting*".[61]

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59 An interconnector's congestion revenue is effectively the congestion rent captured from price differentials across two zones.

60 See FN51.

61 Ofgem (2014) Decision to roll out a cap and floor regime to near-term electricity interconnectors.

United States

3.14 Similarly, in the US, ISOs[62] tend to carry out different investment tests for the different drivers of transmission network investments. FERC Order 1000 requires that all asset classes (transmission and non-transmission solutions) be considered. Interconnectors (referred to as "interregional assets" in the US)[63] are included in an ISO's transmission plan, but are evaluated separately in joint committees with other ISOs. For clarity, interregional assets are those which connect the control areas of two separate ISOs.

3.15 NYISO distinguishes between three requirements of transmission network investments:

- reliability need (addressing potential violation of the reliability criteria);[64]
- economic requirements (relieving congestion costs); and
- public policy requirements (assets required by any local and/or federal policy action).[65]

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62 The US electricity network is divided into ten "regions".[62] Seven of these "regions" consist of a single Independent System Operator ("ISO") or a single Regional Transmission Organisation ("RTO"), which are non-profit organisations with functions similar to a traditional SO. These ISOs and RTOs also take the role of central planners of their respective transmission networks. An ISO or RTO can cover a single or multiple states, and are subject to regulations at the federal level (via the Federal Energy Regulatory Commission, "FERC"). In this report, we focus primarily on the NYISO and PJM ISOs.

63 In the GB (or European) context, an "interconnector" refers to a transmission asset that connects two different price zones. As nodal or zonal pricing does not exist in GB, interconnectors are, in practice, assets that connect the GB network with electricity networks in mainland Europe. However, the US electricity market does feature nodal pricing, with multiple price nodes often within the control area of a single ISO. Transmission assets that connect the control areas of two different ISOs are referred to as "interregional" assets in the US. This is similar to the NEM definition of an "interconnector".

64 These are set by the North American Electric Reliability Corporation ("NERC") for both NYISO and PJM with a Loss of Load Expectation target of less than 1 day in 10 years.

65 Unlike reliability and economic needs, public policy needs are identified by the New York Public Service Commission ("NYPSC"), rather than by NYISO. Further details of the NYPSC's role in NYISO transmission tests can be found in ¶3.32 onwards.

3.16 Similar to NYISO, PJM distinguishes between the reliability need and economic requirements, but includes assets driven by public policy requirements in its transmission planning using an entirely separate process. They are not subject to the PJM investment tests identified below.

3.17 This additional consideration of public policy requirements was mandated by FERC Order 1000. FERC considered that this "supports rates, terms, and conditions of transmission service…that are just and reasonable and not unduly discriminatory or preferential."[66] The need for both reliability and economic assets was emphasised in FERC Order 890.[67]

3.18 Interregional transmission investments between either NYISO or PJM and other regions are also treated separately. Interregional committees are jointly set up via agreements between neighbouring ISOs to plan and coordinate these investments. For example, the Northeastern ISO/RTO Planning Protocol is responsible for planning interregional transmission investments between the NYISO, PJM and ISO-New England regions. The decisions made in these committees are however taken into account when NYISO and PJM perform their intraregional transmission planning.

Summary

3.19 Table 3-1 summarises the types of transmission solutions in each case study.

Table 3-1: Types of transmission solution

Case study	Country	Asset need	Asset type
SWW	GB	Network deepening and network expansion	Mainly onshore networks,[68] within price zones
NOA	GB	Network deepening and network expansion	Mainly onshore networks, within price zones

66 FERC Order 1000, ¶166.

67 FERC Order 890, FN232.

68 Investments in 'bootstraps', or undersea links connecting different parts of GB (i.e. within a single price zone), are technically offshore networks. However, these represent a minority of the investments under the SWW.

Case study	Country	Asset need	Asset type
Interconnectors	GB	Network expansion; driven by net economic efficiency improvements (consumer-focused)	Subsea, between price zones
OFTOs	GB	Connection to offshore wind farms; generation-led	Offshore networks, within price zones
NYISO	US	All network investments (including non-transmission solutions); distinction made between Reliability Need, Economic, and Public Policy projects	Onshore and offshore networks,[69] between price nodes
PJM	US	All network investments (including non-transmission solutions); distinction made between Reliability Need and Economic projects	Onshore and offshore networks, between price nodes

3.20 As shown in Table 3-1 above, the energy markets in GB and US have investment tests that differentiate between asset types to meet different system needs. This is different from the RIT-T test in the NEM, which seeks to apply a single approach to all transmission system needs and asset types.

B. Methodology of investment tests

3.21 Investment tests typically apply a form of CBA to calculate the net benefit of a potential solution to meet a system need. However, the approach to the calculation might differ in the following ways:

69 Some stakeholders have in the past discussed to possibility of proposing an offshore transmission asset as a Public Policy project. Source: North America Transmission (September 2016) Proposed Public Policy Requirements.

- First, different investment tests have **different evaluation criteria**. Investment tests in the US typically consider both the impact on all consumers and producers, and congestion rents. By contrast, other jurisdictions only include the impact on consumers in a defined area (e.g. the GB case studies), while others (depending on the need the solution proposes to address) focus on cost minimisation alone.[70] Additionally, while some jurisdictions cite the need to consider option value, it is unclear how it is applied in practice.[71]
- Second, different jurisdictions have **different approaches to discounting** the expected cost and benefits. The jurisdictions reviewed in this report tend to set a single rate when assessing a specific investment need, which is either based on an average commercial rate, or a social rate set by governments.
- Third, different investment tests consider **different time horizons** over which to discount costs or benefits. The jurisdictions reviewed in this report consider a pre-defined fixed time horizon, which is typically shorter than the economic useful life of the asset, although some jurisdictions consider the entire economic useful life. This may affect the overall result of the CBA depending on the scenarios (and on the discount rate) relied on in the assessment.
- Fourth, jurisdictions can take **different approaches to considering generation (or demand-side) alternatives** to transmission. For example, jurisdictions may consider individual investments on a standalone basis (i.e. to deliver the solution to a particular issue over a fixed timeframe). Equally, some jurisdictions may compare ‘packages’ of investments that deliver different benefits over different time horizons.[72] While the assessment of ‘packages’ may be more complex, it may be more appropriate than ‘standalone’ assessment of individual investments that may not capture the economies of scale / scope associated with incremental investments.

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70 Note that no jurisdiction includes externalities, such as the impact on the competitiveness of energy-intensive industries, although externalities can be introduced elsewhere through other policy instruments such as generation subsidies. Ofgem does, however, include certain non-quantifiable benefits.

71 The RIT-T also in principle includes the option value of the investment (see ¶4.43).

72 For example, in PJM, two different options being compared may include one option that solves a particular reliability problem for 5 years, and another option that solves the same reliability problem for 7 years (albeit at an incremental cost relative to the first option).

Great Britain

3.22 For GB onshore transmission investments assessed under the SWW, a CBA is run by the TO. The CBA compares network reinforcement to several counterfactual options including a 'no-build' option. The costs and benefits are estimated over the lifetime of the investment asset. The expected project cost should be less than the cost to consumers relative to the 'no-build' option.[73] The discount rate is set at the regulated level of the Weighted Average Cost of Capital ("WACC"). Ofgem assumes all transmission assets considered under SWW have a useful life of 40 years, and uses this as its fixed time horizon to assess the benefits.

3.23 For GB onshore transmission investments assessed under the NOA, the SO collects potential technical solutions proposed by the TOs, and may also add its own solutions. A CBA is run by the SO to compare projected costs and monetised benefits over the project's life. The methodology underpinning the CBA is a single year least-worst regret approach.[74] The discount rate is based on the published Social Time Preferential rate ("STPR") which is 3.5% in real terms (and has been since 2003). The NOA, mimicking the approach of the SWW assessment, uses a time horizon of 40 years.

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[73] *"The CBA will evaluate the economic net benefit to consumers of a network reinforcement compared to the counterfactual that no reinforcement is undertaken."* Ofgem (November 2017) Guidance on the Strategic Wider Works arrangements in the electricity transmission price control, ¶2.27.

[74] This involves calculating, for each transmission investment option (including 'do nothing' option), the 'worst congestion costs' across four pre-defined scenarios, then selecting the option with the lowest 'worst congestion cost'. This approach avoids attributing a direct probability to each of the scenarios, but implicitly gives the greatest weight to the most 'negative' scenario in terms of total congestion impact. For a full worked example see the 'Investment Test: Network Options Assessment (NOA)' in Appendix 2. As shown in the Appendix, this approach creates a risk of a 'false positive' outcome, whereby 'too much' investment is undertaken to avoid the high downside of a relatively unlikely scenario.

3.24 For interconnectors in GB, Ofgem adopts a relatively mechanistic approach to setting cap and floor levels.[75] A regulated Cap and Floor regime is applied so that the revenues earned by interconnectors cannot exceed or fall below certain pre-determined thresholds (any revenues above the cap are then returned to consumers; whilst consumers 'top up' any revenue shortfalls if in a particular year the congestion revenues are low).

3.25 The cap is set at an approximation of a reasonable return to shareholders (linked to a notional cost of equity); this is to compensate GB consumers for the support they provide at the 'floor'. In exchange for the cap on revenues, the floor is set to approximate the cost of debt and is intended to reduce the downside risk for prospective investors.[76]

3.26 Ofgem undertakes the CBA for an interconnector by assessing the likely GB net consumer welfare from the interconnector investment and does not consider consumers in other countries nor the generators in either of the connecting countries. Ofgem uses a social discount rate but a developer can provide a different rate with acceptable justification. The time horizon considered for interconnectors is the duration of the Cap and Floor regime, that is, 25 years.[77]

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75 Interconnectors are also allowed to undertake merchant investments (i.e. without a Cap and Floor arrangement). To do so, they need apply for an exemption from certain EU rules and regulations. There are currently two GB-France interconnectors seeking this approach – ElecLink and Aquind.

76 The level of the cap and the floor is taken into account in the consumer-focused CBA as follows: the regulator estimates the quantum of interconnector revenues (annual or cumulatively over a number of years) that are expected to fall below the level of the floor, and calculates the amount of 'top up' expected to be required from consumers to ensure the interconnector receives the floor revenues. The regulator also estimates the quantum of interconnector revenues that are expected to exceed the cap, which would be 'clawed back' for the benefit of consumers. These are applied through changes to transmission charges. Both of these elements (labelled 'net project Cap and Floor payments') are added to the overall consumer CBA that drives the regulator's decision.

77 Note that, as with the proportion of costs and revenues subject to GB regulation, interconnectors can apply for exemption from the regulated Cap and Floor regime as well.

3.27 In GB, multipurpose projects (or, anticipatory investments)[78] can also be considered as part of the Cap and Floor regime. The FAB Link interconnector between France and GB is an example of a multipurpose project. The initial proposal was for a route across the Island of Alderney (in the Channel between France and GB), designed to enable connection of future tidal stream energy in States of Alderney waters.[79] The connection of new tidal energy generator reflected an optionality that the interconnector (primarily designed to connect GB and French electricity markets) would bring.

3.28 In Ofgem's Initial Project Assessment of FAB Link under the Cap and Floor regime, the regulator explicitly considers the option value of being able to connect to future tidal generation in the States of Alderney.[80] This optionality was included in Ofgem's hard-to-monetise assessment, with the derived benefit being that *"greater interconnection allows for the possible development of projects into Multi-Purpose Projects (MPPs) in the future".*[81]

3.29 For OFTOs, Ofgem designs a regulatory regime for competitive tendering. In this process, bidders select a revenue stream that covers the cost of owning and operating the asset. Bidders also select their own discount rate in their bids which is not made public. The time horizon considered for OFTOs is 20 years. Winning bidders receive a guaranteed revenue stream in line with their bid over the period. As an OFTOs 'must' be built to guarantee the physical connection to a particular offshore wind farm generator, Ofgem only focuses on minimising the cost of that connection when evaluating the investment test. As explained at ¶3.12, although OFTOs have an option to construct the transmission asset themselves, this option has not yet been used, and instead OFTOs have followed the 'generator-build' model.

78 This refers to transmission assets that have a strong optionality component, i.e. are able to deliver multiple purposes (for example they may be over-sized in order to enable future connections to new generation to take place). By nature, they appear 'suboptimal' from the perspective of a single project, but are optimal when the embedded optionality of future cost reduction (or other benefits) is taken into account.

79 FAB, FAB Link submits application for an Alternative Offshore Cable Route around Alderney, 28 November 2017, accessed at http://www.fablink.net/fab-link-submits-application-for-an-alternative-offshore-cable-route-around-alderney/.

80 Ofgem, Cap and floor regime: Initial Project Assessment of the FAB Link, IFA2, Viking Link and Greenlink interconnectors, March 2015, ¶3.5.

81 Ofgem, Cap and floor regime: Initial Project Assessment of the FAB Link, IFA2, Viking Link and Greenlink interconnectors, March 2015, page 40.

3.30 There is no single 'global best practice' in terms of using social or commercial discount rates when assessing transmission investments, but in GB the prevailing consensus is for the use of a social discount rate. In 2012 the Joint Regulator Group ("JRG") considered the issue of "*how a regulator should discount costs and benefits when assessing a CBA where a firm finances the investment but benefits mainly accrue to consumers*".[82] While the group found that this is not an area where there is a consensus among academic economists, the JRG noted that the two most common approaches to discount rates are:

- STPR, the social rate given by the HM Treasury Green Book; and
- the relevant WACC, typically estimated by regulators for the firm(s) in their regulated market(s).

3.31 The JRG concluded, following a consultation, that the most appropriate approach is a so-called 'Spackman approach' which discount all costs (including financing costs as calculated based on a WACC) and benefits at the STPR.

[82] Joint Regulator Group (2012) Discounting for CBAs involving private investment, but public benefit.

United States

3.32 **NYISO** effectively runs three separate investment tests; one for each type of need (see ¶3.15). The same discount rate is used to assess all assets – an average of each of the weighted average costs of capital of all the incumbent TOs in the NYISO region. This was 7.0% in 2017 and 6.8% in 2015. The individual test methodologies are as follows:

- For investments required to meet a reliability need identified by NYISO, NYISO requests both market-based and regulated solutions from the TOs.[83] NYISO evaluates the technical viability and the cost-efficiency of each solution which includes generation, transmission and demand-response solutions.[84] Market-based solutions are preferred over regulated solutions unless the market-based solutions are not viable to meet the reliability need in a timely manner. These solutions are assessed over a 10-year horizon.
- For investments required to meet an economic need (e.g. relieve congestion costs), NYISO first assesses which type of solution (generation, transmission or demand-response) is most likely to produce the greatest net benefit. NYISO then requests and evaluates specific transmission network solutions over a 10-year horizon. These projects must exceed USD 25 million in cost and have a benefit-cost ratio of greater than 1.0 for consideration.

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83 Market-based solutions refer to both transmission and non-transmission solutions that are expected to recover their costs from the NYISO's Energy, Capacity and Ancillary Services markets, or from private contracting agreements. Regulated solutions are those expected to recover their costs from NYISO's tariffs.

84 Present value of the sum of capital, engineering and design, and procurement costs; present value of costs per MW; expandability of proposed solution, operability and performance, availability of property rights, and schedule for project completion.

- For investments required to meet a public policy need identified by the New York Public Service Commission ("NYPSC"), NYISO requests and evaluates all potential solutions including generation, transmission and demand-response solutions. If a transmission solution is required, NYISO then evaluates the proposed transmission solution and identifies the most cost-efficient solution. The NYISO will also consider additional metrics where they are relevant to the stated public policy need. These could include changes in production costs, emissions, congestion, or any additional metrics deemed necessary by the NYPSC. This evaluation is reviewed by NYISO stakeholders and the NYISO Board may select a solution. Only transmission solutions will be eligible for cost recovery through a tariff.

3.33 For investments to meet an economic need, NYISO undertakes a voting approach to overcome the uncertainties in identifying the beneficiaries for cost allocation. Beneficiaries of each project are then identified based on the relative load savings and vote on the proposed transmission project. Projects that receive a supermajority of 80% or over will be approved and can receive regulated cost recovery through tariffs.

3.34 **PJM** effectively runs two separate investment tests; one for each type of need (see ¶3.16). However, they are interrelated in that a reliability asset can be considered an economic asset if it meets certain criteria. The same discount rate is used to assess all assets – a weighted average of the costs of capital of all the incumbent TOs in the PJM region. This was 7.4% in 2017 and 2016, and 7.8% in 2015. The test methodologies are as follows:

- For reliability assets, PJM first evaluates if the proposed solution meets the identified need, then evaluates the cost. The cost is the present value of the revenue requirement needed to fund the costs of enhancement for the first 15 years of the asset's life. PJM then assesses if any of the proposed solutions meet the criteria for an economic asset if they were to be enhanced or expanded (see below).
- An economic asset is constructed if its benefit-cost ratio is above 1.25. As with reliability assets, the cost is the present value of the revenue requirement needed to fund the first 15 years of the asset's life. The benefits are the changes in costs of: fuel, operation and maintenance, and emissions of the dispatched resources in the PJM region if the asset is built. They also include expected effects on congestion, load and LMPs in each node, expected effects on PJM's capacity market, and price effects on energy bought from and sold to regions outside PJM. This is further explained in Box 3-1 below.

- If a reliability need is not met by a reliability solution that has been upgraded to an economic asset, then PJM will simply select the most cost-effective solution.

3.35 The output of PJM's transmission planning, the PJM Regional Transmission Expansion Plan ("PJM RTEP") is eventually reviewed by PJM's Board of Managers, who have the final authority for its approval and implementation.

3.36 Public policy assets in PJM are assessed via the State Agreement Approach. This is a separate process from PJM's cost benefit assessment discussed above. Entities authorised by their respective states, individually or jointly, may agree voluntarily to be responsible for all allocation of costs of a proposed transmission investment that addresses some public policy requirement. These assets are included in the PJM RTEP, and not assessed by PJM directly. This contrasts with the NYISO approach, in which a state body proposes a public policy need, but NYISO runs the investment test and ultimately decides on the preferred solution.

Box 3-1: PJM economic asset benefits formula[85]

For economic assets in PJM, the benefits to be compared to a project's cost are evaluated by the sum of the Energy Market Benefit ("EMB") and the Reliability Pricing Model Benefit ("RPMB"):

$$Benefits = Energy\ Market\ Benefit + Reliability\ Pricing\ Model\ Benefit$$

The Energy Market Benefit is evaluated by the following formula:

$$EMB = (0.5 \times \Delta\, Total\ Energy\ Production\ Cost) + (0.5 \times \Delta\, Load\ Energy\ Payment)$$

The Change in Total Energy Production Costs is the difference (with and without the expansion) in estimated total:

(1) annual fuel costs;

(2) variable operation and maintenance costs;

(3) emissions costs; and

(4) costs for purchases outside the PJM region, if appropriate.

The Change in Load Energy Payments is only measured in zones that show a decrease in Load Energy Payments and is given by the following formula:[86]

$$\Delta\, Load\ Energy\ Payment = \left(\sum hourly\ zonal\ load \times\ hourly\ LMPs\right) - Value\ of\ FTRs$$

The Reliability Pricing Model Benefit is evaluated by the following formula:

$$\mathrm{RPMB} = (0.5 \times\ \Delta\ Total\ System\ Capacity\ Cost) + (0.5 \times \Delta\, Load\ Capacity\ Payment)$$

$$\Delta\, TSCC = \ \Delta\ \left(\sum MW\ cleared\ in\ Base\ Residual\ Auction\ \times Clearing\ price\right)$$

$$\Delta\, LCP = \Delta\left(\sum Estimated\ zonal\ load \times\ Final\ Zonal\ Capacity\ Prices\right)$$

85 Source: PJM Manual.

86 PJM does not take into account zones that show an increase in the Load Energy Payments. *"In determining the Change in Load Energy Payments, only zones that show a decrease will be considered"* PJM Manual 14B, pg 101.

Evaluation criteria for interconnector assets

3.37 As explained in ¶2.62 and in Figure 2-2, the assessment of interconnector costs and benefits may involve five different categories of benefits, including:

(1) Consumer surplus (increases in the importing region);

(2) Producer surplus (increases in the exporting region);

(3) Congestion rent (accrues to the owner of the interconnector);

(4) Negative transfer from consumers to producers (i.e. consumers pay in the exporting region); and

(5) Positive transfer from producers to consumers (i.e. consumers benefit in the importing region).

3.38 As set out in ¶2.62, not all investment tests take all five impacts into account.

3.39 Table 3-2 below illustrates how this differs between jurisdictions.

Table 3-2: Differences in interconnector assessment between jurisdictions

Case study	Country	Benefits considered				
		CS	PS	Rent[87]	-ve transfer	+ve transfer
GB Interconnectors	GB	✓ (GB only)	✓ / × (secondary)[88]	✓ (part only)[89]	✓ (GB consumers only)	✓ (GB consumers only)
NYISO	US	✓	✓	✓	×	×
PJM	US	✓	✓	✓	×	×
EU Interconnectors (ENTSO-E, advisory only)	EU	✓	✓	✓	×	×

Source: FTI-CL Energy analysis.

87 As explained in FN47, typically the congestion rent of the newly built interconnector is taken into account, however the cannibalisation effect on any pre-existing interconnectors (connecting the same two zones) may also be considered in the overall social welfare assessment.

88 Ofgem does estimate and publish the impact of the interconnector investments on GB producers, but its main criterion for approving (or not) an investment focuses on GB consumers only.

89 Ofgem focuses on the part of the interconnector revenues that are ‘clawed back’ for the benefit of GB consumers, or those that are paid for by GB consumers to pay for the floor, where needed.

3.40 In the Netherlands, the Office of Energy Regulation (“DTe”) also considers that interconnector investments, in particular, need to be beneficial for domestic consumers. For example, in its decision on NorNed (a fully regulated link between Norway and the Netherlands, owned by TenneT and Statnett), DTe indicated that it “*must assess the cable from the point of view of those connected to the grid/grid users, in other words consumers and producers. Moreover, the Director of DTe attaches importance to ascertaining through a separate test that the cable will, in any event, have a positive value for consumers*”.[90] DTe’s rationale for this approach is based on the fact that it is ultimately to grid users who bear the risk associated with the interconnector, yet have limited control over the project.

3.41 Given the re-distribution of benefits that a new interconnector can potentially trigger, particularly *between* consumers in the two connecting regions, and also between consumers and producers *within* a given region, mechanisms may need to be put in place to mitigate the adverse impact on particular classes of stakeholders. This issue has been recognised in the EU and a mechanism known as Inter-TSO compensation (“ITC”) was put in place in 2011 to enable TSOs in neighbouring countries to partially compensate each other for hosting ‘transit’ flows, and specifically for:[91]

- the costs of <u>losses incurred</u> by national transmission systems as a result of hosting cross-border flows of electricity; and
- the costs of making infrastructure <u>available</u> to host cross-border flows of electricity.

3.42 Separate to calculated benefits, externalities are often considered qualitatively and play a secondary role in other jurisdictions. For example, in the UK, Ofgem qualitatively evaluates so-called “hard-to-monetise” benefits such as flexibility, development of a ‘meshed’ network, sustainability and strategic value, when assessing interconnectors for the Cap and Floor regime.

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90 DTe (2004) Decision on the application by TenneT for permission to finance the NorNed cable in accordance with section 31 (6) of the Electricity Act of 1998, ¶54.

91 ACER (2017) Report to the European Commission on the implementation of the ITC mechanism in 2016.

C. Process and application of the investment tests

3.43 The SO and/or regulator in other jurisdictions are often significantly involved in implementing transmission investment tests. This is intended to facilitate greater information coordination, to provide a more independent view on transmission planning, and provide an additional/complementary layer of verification of the costs and benefits.

Great Britain

3.44 For the SWW, the TO identifies needs and provides information to the SO to facilitate its various assessments. For this, the TO is required to:

- create a project plan using the National Electricity Transmission System Security and Quality of Supply Standards ("NETS SQSS") to determine the capability of the transmission system; and
- provide relevant information for the SO's eligibility assessment,[92] needs case, project assessment,[93] and on its delivery strategy.

3.45 Third-party stakeholders are consulted for over 8 weeks. An SWW process can be initiated by the TO at any time and will last for approximately 12 to 15 months.

3.46 For the NOA, the SO is required to identify the required new transmission projects annually. The local TO then should use the outputs alongside their own assessments. Third-party stakeholders are given the opportunity to submit feedback and develop sensitivities. However, the NOA has no binding impact on the SWW or actual investment decisions – its primary purpose is purely advisory.

92 This checks that: (1) the proposed asset will deliver additional capacity or wider system benefits; (2) the costs cannot be recovered under any other GB regulation; and (3) the expected delivery cost is above a pre-determined threshold.

93 This is the actual CBA.

3.47 For interconnectors in GB, projects are initiated and led by developers (including non-TSO developers). The regulator decides if a Cap and Floor regime is in the interests of consumers and opens an assessment window where initial and final assessments are subject to a consultation process following which they are approved (or not approved) by Ofgem. The investment / regulatory test process is approximately two to three years for a 25-year regime. The regulator reviews the CBA submissions from developers, but it makes its own quantitative assessment of the CBA, and also determines the actual cap and floor levels. In addition, the regulator carries out an *ex-post* review to verify the actual costs incurred (also known as a Post-Construction Review) and can result in adjustments to the cap and floor levels.

3.48 OFTOs can either be a 'generator-build' model where the generator designs and constructs the asset which is later transferred to the OFTO, or an 'OFTO-build' model where the OFTO designs, constructs, owns and operates the asset.[94] During the tender process, developers are not allowed to have contact with bidders nor to know their identities. Each tender stage lasts for approximately six months.

United States

3.49 The NYISO planning process is run once every two years. The ISO specifies reliability, economic and public policy needs and runs the cost-benefit analyses. TOs and any other interested parties (if qualified) can propose solutions to meet a system need. The process receives inputs from local TO planning processes.

3.50 PJM's planning process runs over an 18 month overlapping cycle beginning every September and extending to the following February. Similarly to NYISO, the SO specifies reliability and economic needs and runs the cost-benefit analysis. TOs and any other interest party can propose solutions.

94 To date, all OFTOs have elected to use the 'generator-build' option.

Roles in investment tests

Table 3-3: Roles in investment tests

Case study	Regulator	SO	TO	3rd parties
SWW	Reviews submissions; makes decision	Supports needs assessment; produces updated CBA later in the process	Identifies need; proposes solutions; runs initial CBA	Can participate in consultations, and in competitive procurement for a subset of asset types
NOA	No direct role but considers NOA output in SWW assessment	Identifies need; collates options from TOs and may add its own; publishes annual report, runs NOA but has no binding impact	May work with SO to identify transmission options; uses NOA output alongside own assessment (SWW)	Can give feedback and help develop testing sensitivities
Interconnectors	Opens application window; considers applications; makes decision	Assists the regulator by publishing a system impact and ancillary services analysis on the proposed interconnectors – the cost-benefit implications for GB consumers are included in the regulator's assessments	The TO is consulted on the connection options for an interconnector, and negotiates with the SO and the developer to identify the most economic and efficient option (process is known as Connection and Infrastructure Options Note ("CION")	Developers (third-parties or TOs) initiate and lead; submit relevant information

Case study	Regulator	SO	TO	3rd parties
OFTOs	Assesses information; awards license; approves Final Transfer Value and Tender Revenue Stream	Negotiates with the TO to identify the most economic and efficient connection point for the OFTO	The preferred OFTO works with the generator to produce a range of options for connection points in the form of grid references to the SO	Developers (build asset) and bidders (want to be granted license to operate asset); developers request start of tender process; developers and bidders must provide relevant information
NYISO	FERC sets country-wide broad guidance for ISOs on transmission planning methodologies and cost allocation	Identifies needs; runs CBA;[95] publishes solutions and decides on preferred solution	Perform transmission studies that are used in SO planning process; propose solutions	Qualified parties can propose solutions and participate in planning process
PJM	FERC sets country-wide broad guidance for ISOs on transmission planning methodologies and cost allocation	Identifies needs; runs CBA (monitors annually for efficiency projects); decides on preferred solution and reviews if projects should be continued after changes	Propose solutions	Various Committees take active planning role; Committee membership open to all (e.g. customers, providers, regulators)

95 The New York Public Service Commission (NYPSC), the New York regulator of public utilities, can also require NYISO to evaluate specific solutions as Public Policy assets.

Box 3-2: Investment tests for interconnectors in the EU

In the EU context, investment tests for interconnectors are undertaken at a regional level led by European Network of Transmission System Operators for Electricity ("ENTSO-E") across the Member States. This is because there is potential for transmission investment in one country to impact the overall flows across the system.

ENTSO-E is the European electricity transmission system operator group and has the primary objective to ensure that the electricity transmission network is managed and functioning optimally to facilitate cross-border flows across Europe.

Every second year, ENTSO-E develops a Ten Year Network Development Plan ("TYNDP") which provides an integrated view on transmission planning in six regions across Europe (North Sea, Baltic Sea, Continent Central East, Continental South East, Continental Central South and Continental South West). The TYNDP adopts a three-step approach; first with a Europe-wide market modelling assessment, second with regional market and grid modelling assessment, and third with a CBA assessment on specific project options. The CBA considers a number of benefits including security of supply, socio-economic welfare (including consumer and producer surpluses), renewables integration, variation in losses, and variation in CO_2 emissions. From a cost perspective, it considers total project expenditure. In addition, the assessment also takes into account wider issues such as the environmental and social impacts. National bodies provide input or recommend projects to ENTSO-E to be included in the TYNDP either directly or through the TSO/national regulator.

The recommendations set by the TYNDP are purely advisory and non-binding. The national regulatory bodies maintain the primary role to implement transmission investment across jurisdictions through their own internal processes.

From the projects selected by the TYNDP, certain projects can be nominated as a Project of Common Interest ("PCI"). These projects are key infrastructure projects that significantly impact multiple EU countries, enhance integration, competition, security of supply and contribute to EU's wider energy and climate objectives. These projects benefit from a more streamlined and efficient approvals process and may be eligible for additional funding from the Connecting Europe Facilitate ("CEF") during the development phase. Under Regulation 347/2013, Article 12, PCIs may also apply to the national regulatory authorities to have their revenues regulated and recovered from transmission charges.

D. Addressing potential market failures

3.51 Investment tests have a role in mitigating a number of market failures that might otherwise arise in the absence of the test. In particular, its role relates to:

- the information asymmetry between the TOs, the regulator and third-party providers (“information asymmetry”);
- the lack of certainty regarding future evolution of supply / demand and therefore the actual need for a transmission investment to be undertaken (“imperfect information”);
- the risk of imperfectly coordinated investments due to misaligned incentives (“coordination failure”); and
- inadequate allocation of risks and rewards among parties involved (“misallocation of risks and rewards”).

3.52 The different investment tests have different approaches to mitigating the risk of market failure. Some findings include:

- Jurisdictions typically rely on a significantly-involved SO and/or regulator;
- The US adopts a beneficiary-pays principle (although applying this principle can be difficult and some methods have led to questionable outcomes);
- No jurisdiction appears to have effective coordination with gas network investments;[96] and
- Investments in interconnectors across two distinct systems are viewed as ‘special cases’ (e.g. regulator-led approach in GB and committee-led approach in the US).

3.53 These approaches are set out below in Table 3-4 below.

[96] The NYISO Board has previously (independent of its regular transmission planning process) examined this issue.

Table 3-4: Addressing potential market failures

Case study	Information asymmetry	Imperfect information	Coordination failure	Misallocation of risks and rewards
SWW	Public consultation; Synergy with NOA but limited third-party involvement for non-network solutions)	Monitored closely by regulator both on ex-ante assessments and ex-post information submissions	Limited considerations with gas or generation; Interconnectors assessed separately	Adjustment to allowed revenues; Risk sharing agreement in place; Some competitive procurement from 3rd parties possible
NOA	Public consultation; Synergy with SWW	Least-worst regret approach & SO-led scenarios (Future Energy Scenarios)	Limited coordination with gas; Comments on the total amount of interconnection but not on specific projects; Helps the industry gain a common view of the direction of travel (including SWW)	Not a key issue, as output is non-binding
Interconnectors	Regulator-led CBA; information submissions from developers mandatory	Risk-sharing mechanism between developers and consumers; Discretionary scenario analysis by the regulator	Independent developers are incentivised to overcome coordination failure between countries (TSOs) to maximise profits. However, there are still outstanding issues.	Cap and Floor limit risk and rewards, however only GB consumer welfare considered (GB producers and impact on other countries are secondary)
OFTOs	Regulator-led assessment; Information submissions from developers mandatory	Regulator leads on assessments at various tender stages	Generator-led investment, hence limited risk of coordination failure between wind developers and transmission operators	Regulatory regime and competitive tender process limits the risk borne by OFTOs and cost to GB consumers

Case study	Information asymmetry	Imperfect information	Coordination failure	Misallocation of risks and rewards
NYISO	ISO-led assessment; Information submissions enforced, investment needs determined largely by the ISO.	Scenarios analysis developed and performed by the ISO when necessary[97]	Separate cross-regional planning committees with neighbouring ISOs decide on interconnector investment; NYPSC identifies public policy needs	In theory, costs of investment are to be recovered from parties in proportion to the benefit derived from the transmission asset. However, applying this principle can be difficult and some methods have led to questionable outcomes.[98]
PJM	ISO-led assessment; information submissions enforced. Investment needs determined largely by the ISO.	Scenario analysis developed and performed by the ISO when necessary	Separate cross-regional planning committees with neighbouring ISOs decide on interconnector investment; Limited coordination with gas	In theory, costs of investment are to be recovered from parties in proportion to the benefit derived from the transmission asset. However, applying this principle can be difficult and some methods have led to questionable outcomes

97 Variables considered are stated to be: load forecast uncertainty, fuel prices, new resources, retirements, transmission network topology, and limitations imposed by proposed environmental legislation.

98 NYISO rules require developers to obtain NYPSC approval if they wish to propose cost allocation methodologies that differ from the default arrangement.

Box 3-3: Argentinian transmission expansion reforms in 1992[99]

In 1992, Argentina developed a "Public Contest" method of planning major transmission expansions that is widely considered to be an effective "beneficiary-pays" system. A key feature of this process is that the decision to undertake transmission investment, and the obligation to pay for it, is given to the users themselves.[100]

After a transmission expansion is proposed, the regulator applies the "Golden Rule", which checks if the total costs of generation, transmission and outages would be expected to fall as a result of the proposed expansion (to ensure socially detrimental projects do not go ahead).

The SO then identifies the parties that would benefit from the proposed expansion ("the beneficiaries") and each beneficiary's estimated usage of the new line – **only the beneficiaries are allowed to vote on the proposed expansion.**[101]

Each beneficiary's estimated usage determines **both the weight of its vote** and its **percentage obligation to pay for the expansion**.

If **more than 30% of beneficiaries vote in favour** of the expansion, and **less than 30% oppose it**, the expansion is approved. The construction, operation and maintenance of the facilities are put out to tender, and all beneficiaries are required to pay in proportion to their estimated usage.

This policy appears to have been broadly successful; by 1994, three high voltage lines (with a combined length of 853km) were put out to competitive tender (although the success of the "Fourth Line" has been subject to some debate).

This contrasts with the current NYISO voting system for economic assets, whereby only load serving entities (and not generators or other benefiting parties) vote on the transmission investment.[102]

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99 Hogan and Pope (September 2007) Comments on Wholesale Competition in Regions with Organised Electric Markets, pp 20 - 26. Note that the reforms of 1992 are of greatest interest here; the subsequent reforms in 1998 are not discussed.

100 Note that Argentina has locational marginal pricing.

101 Note that beneficiaries may include suppliers or load serving entities.

102 See ¶3.32.

3.54 While there is no beneficiary pays model in Europe, *per se*, it is notable that, on occasions, classes of potential beneficiaries can find routes to provide financial support to underpin the construction of interconnectors that they believe will be in their economic interest.

- For example, NorthConnect (a planned link between Norway and Scotland) is likely to facilitate greater exports from Norway is being developed by Nordic generators.[103]
- Similarly, Piemonte Savoia (a France-Italy link) is promoted by a group of Italian energy-intensive industrial customers that would be likely to benefit from increased imports of low cost electricity from France into Northern Italy.[104]
- Indeed, arguably, in GB, the regulator, Ofgem, sanctions customer support of interconnector projects if it considers that GB consumers will benefit on account of increased imports.

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103 These include Agder Energi, E-CO, Lyse Produksjon and Vattenfall.

104 EC (2016) Commission Decision of 9.12.2016 on the exemption of Piemonte Savoia S.r.l (Italy) under Article 17 of Regulation (EC) No. 714/2009 for an electricity interconnector between Italy and France.

4. Overview of the RIT-T in the NEM

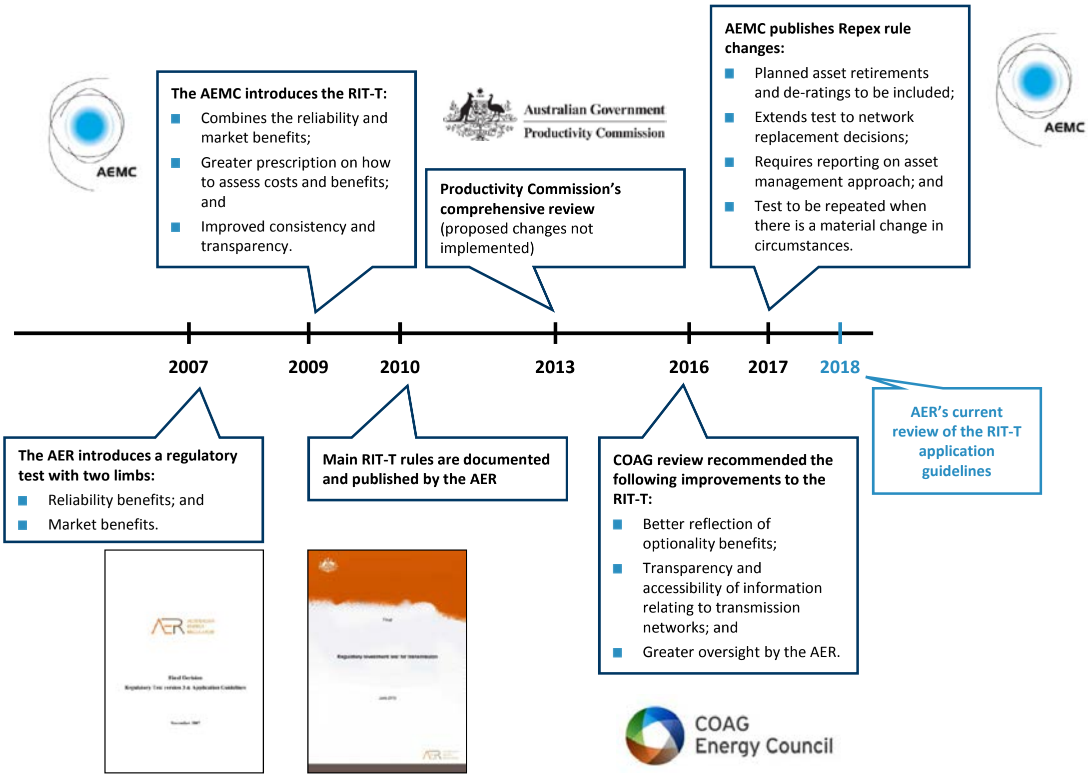
4.1 The RIT-T is the investment test used in the NEM. This section first sets out a brief history of the RIT-T in Australia (Section A) and then summarises the key features of the RIT-T, including the approach to meeting transmission needs, methodology, process and application, and effectiveness at addressing market failures that have been identified as possibly occurring in investment in transmission (Section B). We also highlight key areas where the RIT-T departs from international experience and set out suggestions for further analysis.

A. History of RIT-T in Australia

4.2 The history of the RIT-T in Australia is summarised in Figure 4-1 and described in more detail further below.

4.3 The RIT-T was originally conceived and developed for a particular set of circumstances prevailing around 2009. Although it has been reviewed and updated a number of times since its inception, the actual changes (e.g. the ‘repex’ rule change, see ¶4.8) have been relatively minor and have not explicitly sought to adapt the test to the evolving nature of the NEM.

Figure 4-1: History of the RIT-T in Australia



Sources: AER (Sept 2017) RIT-T and RIT-D application guidelines; AEMC (2017) RIT-T – Repex rule change; COAG (Feb 2017) RIT-T Review; Productivity Commission – Electricity Network Regulatory Framework Review – Vol 2 – 9 Apr 2013.

4.4 Prior to the introduction of RIT-T, a Regulatory Test was applied to assess potential investments in transmission networks. The test consisted of two 'limbs':

- For investments driven by reliability needs, the test was aimed at minimising the costs of meeting a particular reliability requirement.[105]
- For investments driven by the market benefits they deliver, the test would seek to maximise the expected net economic benefits to all market participants (consumers, producers and transmission owners).[106]

105 AER (2007), ¶2.1(a).

106 AER (2007), ¶2.1(b) and Section 4.

4.5 The two ‘limbs’ effectively differentiated between investments within a given price zone (without any direct ‘market benefits’ from increasing the economic efficiency of generating, transporting and delivering electricity),[107] and investments between price zones.

4.6 The Regulatory Test was replaced by the current RIT-T in 2009. As part of the change, the two ‘limbs’ of the regulatory test were combined into a single test. This change was designed to enhance the investment test framework. By amalgamating the reliability and market benefits limbs, the AEMC sought to optimise the decision making process and reduce the risk that efficient options that promote both limbs would be overlooked.[108] This test seeks to identify a ‘preferred option’ defined as the credible option that “*maximises the net economic benefits to all those who produce, consume and transport electricity in the market compared to all other credible options*”. The RIT-T rules specifically note that the preferred option may in fact have negative net economic benefits, given the stated methodology for measuring benefits, where the project is driven by reliability needs.[109]

4.7 In addition to amalgamating the two limbs of the Regulatory Test, the RIT-T sought to provide:[110]

- more prescriptive guidance on assessing market costs and benefits;
- clarity on the consultation process; and
- improved optimisation, consistency and transparency across the assessment of potential transmission investment.

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107 For example, under the previous system, a particular investment to address a reliability requirement may have led to an increase in electricity losses. However, if such additional losses were not part of the costs of that option, they would not have been included as ‘costs’. At the same time, the losses could not have been included as ‘negative market benefits’ either because the investment would have addressed a reliability requirement. This means that negative impacts such as additional losses were “*not to be taken into account in the assessment of a reliability option*” AER (2007), ¶3(c).

108 AEMC (2009) Final Rule Determination. National Electricity Amendment (Regulatory Investment Test for Transmission) Rule 2009. Section 6.3.

109 AER (2010), pp 1.

110 AEMC (2009) RIT-T Rule Change, accessed at: https://www.aemc.gov.au/rule-changes/regulatory-investment-test-for-transmission.

4.8 Since its implementation of the new test has been subject to a number of criticisms. Since 2010, the RIT-T has been reviewed several times by different parties, including:

- In 2013, the Productivity Commission was instructed to assess the NEM's current regulatory framework ("Productivity Commission report"). In particular, it was to make recommendations on benchmarking methodologies and whether the current regulatory regime was delivering economically efficient outcomes with respect to interconnectors;
- In 2016, the Council of Australian Governments ("COAG") Energy Council published a report assessing if the RIT-T remained fit for purpose in the context of the changing Australian electricity market ("COAG Report");
- In 2017, the Australian Energy Regulator ("AER") revised the RIT-T in respect of the replacement expenditure ("AER RIT-T repex revision") rules; and
- Most recently (February 2018), AER issued a consultation on various parts of the RIT-T ("AER February 2018 consultation"), including its: (i) overall effectiveness; (ii) applicability; (iii) alignment with the RIT-D; (iv) level of prescriptiveness; and (v) relationship with the ISP.

4.9 The **Productivity Commission report** recommended that the RIT-T should:

(1) continue to be performed by the Transmission Network Service Providers ("TNSPs"), but should be accompanied by independent analysis from AEMO;

(2) be used by the AER for revenue determinations of those projects;

(3) apply to all large transmission projects above a threshold value, irrespective of whether they are augmentation, replacement or new build;

(4) be triggered when a project exceeds a threshold value that is indexed over time to reflect its real value;

(5) assess a project's effect on reliability as a component of net benefits, and not as a separate criterion;

(6) include a publicly available probabilistic reliability assessment; and

(7) continue modelling the costs and benefits within the power market only, and not include any externalities.

4.10 The **COAG Report** made the following recommendations:

(1) The AER should review the RIT-T guidelines, and consider how the quantification of net benefits could better reflect optionality (including in relation to system security and climate policies and objectives);

(2) Information on transmission networks should be more transparent and accessible, notably in respect of third-parties who may put forward non-network solutions (e.g. strategically located storage, Active Network Management ("ANM"), coordination with DSOs or flexibility contracts with users to optimise the operational capacity of the existing network); and

(3) The merits of increased AER oversight of the RIT-T process should be explored.

4.11 The AER RIT-T repex revision made the following additions to the RIT-T:

(1) Planned asset retirements and de-ratings are to be included in the annual planning reports;

(2) The RIT-T test was extended to include network replacement decisions;

(3) Transmission annual planning reports are now required to report an asset management approach (aligning with a similar requirement for distribution annual planning reports); and

(4) The RIT-T test is to be repeated when there is a material change in circumstances.

B. Key features of RIT-T

4.12 The RIT-T is a cost-benefit assessment of proposed "credible options", where the preferred option using the test is defined as the credible option that "*maximises the net economic benefits to all those who produce, consume and transport electricity in the market compared to all other credible options*".[111]

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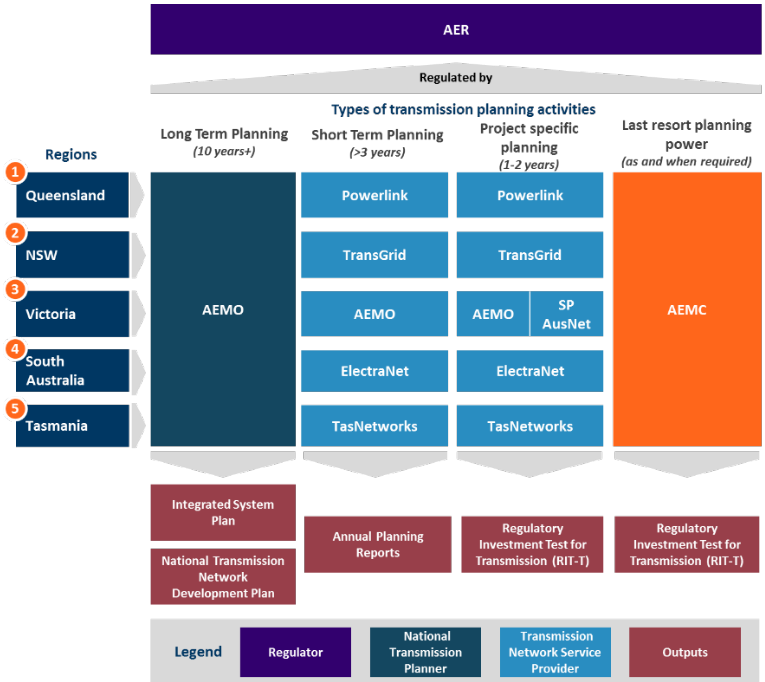
[111] AER (2010) RIT-T Final Guidelines, pp 3.

4.13 RIT-T is one specific element of a wider suite of mechanisms that are defined within the National Electricity Rules ("NER") which are intended to encourage an efficient and transparent planning process. As shown in Figure 4-2, the responsibility for transmission planning in the NEM is shared between AEMO, in its role as National Transmission Planner ("NTP"), and jurisdictional planning bodies for individual regions within the NEM.[112] Among these roles, the RIT-T is focused on the project-specific elements of transmission planning.

Figure 4-2: RIT-T as part of transmission planning in the NEM



Source: FTI-CL Energy analysis.

Note: (1) The years in the figure above refer to the period of time in advance of the need. (2) In the case of Victoria, AEMO has a separate legal function and acts as a TNSP.

112 Transmission planning within each NEM region is generally undertaken by the local TNSPs with AEMO providing mainly forecasting information such as the NTNDP, the Electricity and Gas Statements of Opportunities ("ESOO" and "GSOO"), among others. The only exception is Victoria where AEMO performs the full transmission planning role including the preparation of the RIT-T while the TNSPs retains the asset ownership role.

The Annual Planning Reports largely contain forecasting information and proposed network developments, some of which may eventually be formally proposed under the RIT-T.

4.14 The following sub-sections focus on the key features of RIT-T, including the drivers of transmission investment (Section a), the methodology of the investment test (Section b), the process and application of the test (Section c) and its approach to addressing the market failures (Section d).

a) Meeting transmission needs

4.15 In the NEM, all forms of transmission investment needs are assessed under the RIT-T. This includes both investments driven by reliability needs and those driven by market benefits (such as reduction in fuel consumption through improved dispatch or reduction in involuntary load shedding), interconnectors, and connection of new generators. As explained in ¶4.6, the move from a two-limb test to a single-limb test was a deliberate decision.

4.16 The RIT-T's use of a 'one-size-fits-all' approach contrasts with the GB and US approach which uses different tests for different asset types or purposes. In GB, different investment tests are designed for different asset types such as onshore assets, interconnectors, and offshore transmission assets to offshore wind farms. In the US, different investment tests are design for different needs of transmission investment, such as from an economic, reliability or public policy perspective (see ¶3.5 to ¶3.20).

4.17 The RIT-T's prescriptive approach means that it might not have sufficient flexibility to evaluate some of the strategic or pro-active investments and underpinning value considered in the ISP. Additionally, the RIT-T as currently designed focuses primarily on the incremental value of individual transmission investments. This means that the test might not capture the full strategic value of an investment such as multi-purpose investment or one that requires more significant coordination of transmission and generation.

Suggestion for further analysis #1: Explore whether investment tests for transmission networks in Australia should distinguish between asset needs and/or asset types.

b) Methodology of investment tests

4.18 The RIT-T process is illustrated in Figure 4-3 below and follows the following steps:

(1) A **need is identified** by the TNSP (an "identified need"), which may constitute a reliability corrective action,[113] or an expected increase in the net economic benefit to consumers and producers in the NEM.

(2) **Credible options** are then tabled by the TNSP managing the RIT-T or a third-party.[114] These are options that (i) address the identified need, (ii) are commercially and technically feasible; and (iii) can be implemented in sufficient time.

(3) For each credible option, the TNSP then calculates the **present value of the costs** of the option. This can include (i) construction costs, (ii) operation and maintenance costs, and (iii) compliance (and other administrative) costs. The TNSP may also include other costs it considers relevant, but must first agree to this with the AER before the Project Specification Consultation Report ("PSCR")[115] is made public.

113 A "reliability corrective action" is an action that assists the TNSP in meeting any of the service standards linked to the technical requirements of Schedule 5.1 of the National Electricity Rules or other applicable regulatory rules.

114 A credible option can (but does not have to) have a "proponent", defined as a person that has reasonably demonstrated willingness and potential ability to devote or procure the required human and financial resources to the: (i) technical specification and refinement of the option; and (ii) development of the option – i.e. be willing to be compensated by a reasonable network support agreement in exchange for constructing the option.

115 This is the document detailing the TNSP's needs case.

(4) For each credible option, the TNSP then calculates the **present value of the market benefits** of the option, by comparing the **state of the world with the credible option** to that **without the credible option**. These benefits can include the respective changes in (i) fuel consumption, (ii) load curtailment, (iii) involuntary load shedding, and (iv) a number of other factors.[116] Similarly to costs, the TNSP may also include other benefits it considers relevant, but must first agree to this with the AER. The states of the world with and without the credible option are outputs of this analysis, and can include: (i) a forecast of electricity demand; (ii) the operating, capital and avoidable costs of other projects and network augmentations; (iii) the cost of ancillary services; and (iv) any penalties from failing to meet environmental targets. This exercise must be repeated for all reasonable scenarios.[117] The calculated market benefits under each reasonable scenario must be weighted by the probability of the scenario occurring.[118] The expected present values of market benefits under all reasonable scenarios must then be totalled to give the total expected market benefits, to be compared to total costs. This process is illustrated in Figure 4-4.

(5) Calculated market benefits **cannot include:**

(i) transfers of surplus between consumers and producers; or

(ii) indirect benefits (positive externalities).

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116 Including changes in: costs to parties other than the TNSP; timing of transmission investment; network losses; ancillary services costs; competition benefits; additional optionality values; and penalties avoided.

117 A "reasonable scenario" is a set of variables or parameters that are not expected to change across each of the credible options or the base case. A given reasonable scenario may for example include any combination of the following: (i) forecasts of electricity demand reflecting economic growth and climate pattern assumptions; (ii) the timings and costs of projects planned or proposed other than that being modelled; (iii) the form of environmental regulations; (iv) the discount rate; and (v) generation behaviour.

AEMO effectively sets these scenarios through the National Transmission Network Development Plan. However, in theory, TNSPs performing the RIT-T are free to set their own scenarios. Source: Productivity Commission (April 2013) Electricity Network Regulatory Framework Review, Volume 2, pp 633, FN6.

118 This probability is determined by the TNSP. The AER states that the approach used to assign this probability should match that used to identify the reasonable scenario. Where a TNSP has no material evidence of assigning a higher probability for one reasonable scenario over another, all reasonable scenarios may be weighted equally. Source: AER (September 2017) RIT-T Updated Application Guidelines, pp 31.

(6) Both total costs and total expected benefits must be discounted by an appropriate commercial discount rate to give the present values of costs and benefits. This commercial discount rate can therefore differ between TNSPs, and between the credible options being assessed.[119] Indeed the AER commented that "*the current non-prescriptive approach provides RIT proponents with the flexibility to adjust the discount rate to reflect the risks that different types of projects carry*".[120] Moreover, the discount rate can also be varied under different reasonable scenarios. The exception to this is in the RIT-T in Victoria which relies on the social discount rate (the latest recommendation for this is 7%).[121, 122] Additionally, the ISP, under the current design, relies on the social discount rate.

(7) The credible option with the highest present value of net economic benefits (benefits net of costs) will be chosen.[123]

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119 This differs from the social discount rate of 7% (with a sensitivity of 3% to 10%) recommended by the Australian Office of Best Practice Regulation.

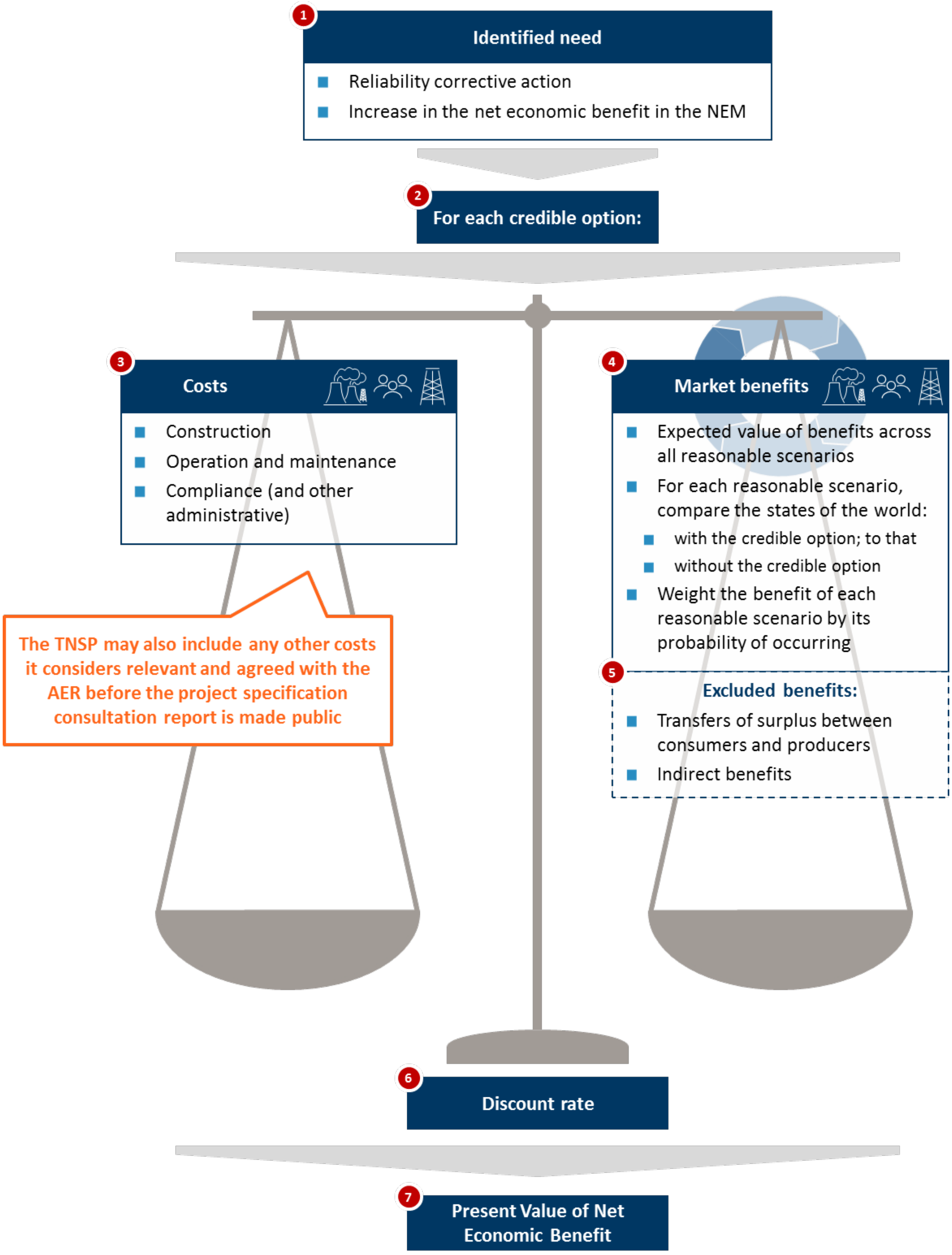
120 AER (February 2018) Review of the RIT-T application guidelines, Section 5.7.

121 Victoria Department of Treasury and Finance (August 2013) Economic Evaluation for Business Cases, Section 6.2.

122 This is higher than the GB social discount rate of 3.5% and is comparable to the commercial discount rates used in PJM and NYISO.

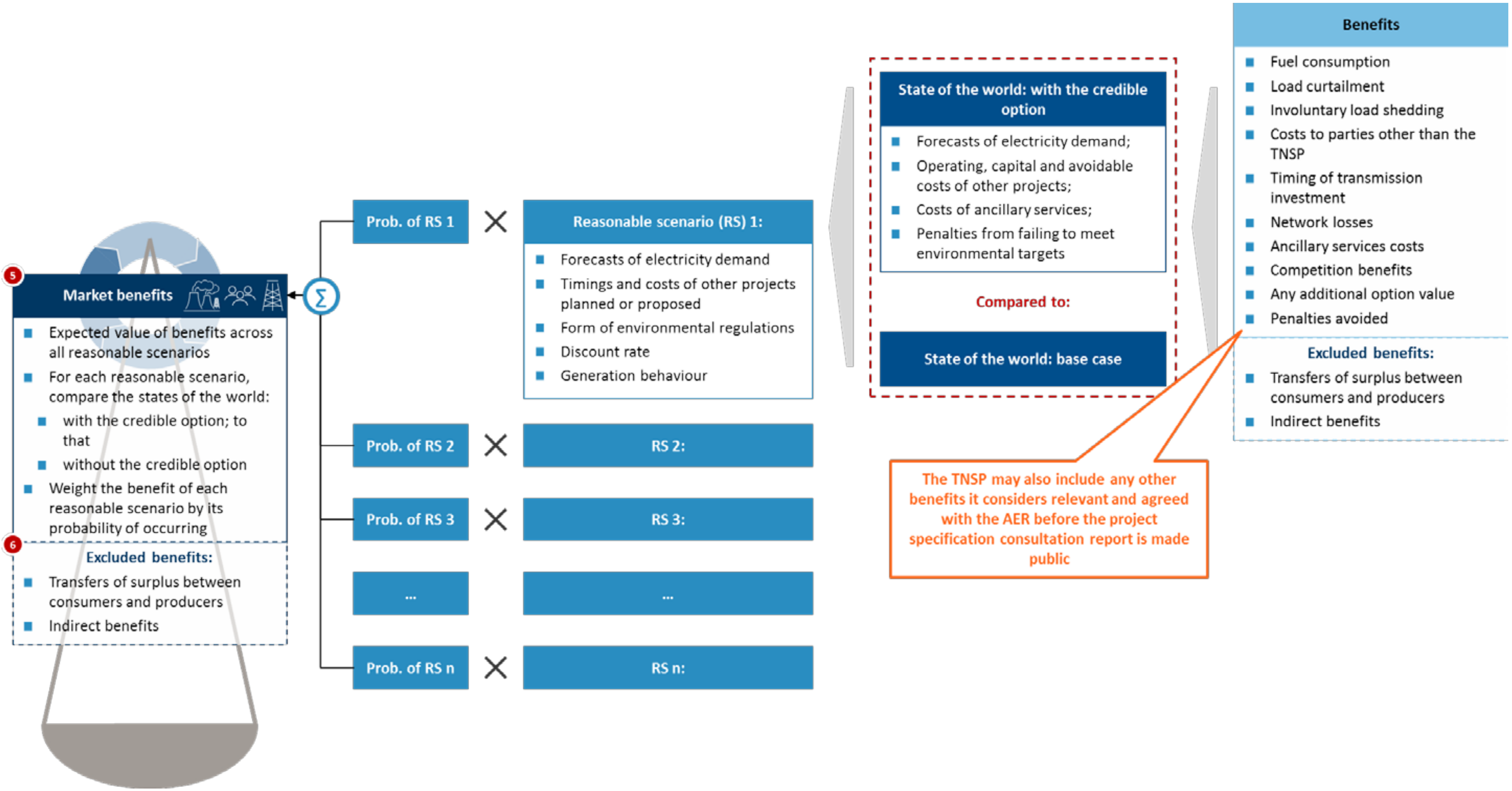
123 Other jurisdictions follow a similar approach; if there is a specific need, the solution with the maximum expected net benefits is selected. There are several exceptions. First, transmission investments to meet a public policy requirement are selected based on the minimum cost. For example, this applies to public policy transmission investments in the US and GB's OFTO regime, which requires bidders to meet certain technical and financial criteria before being evaluated on cost. Second, when assessing GB interconnectors, the regulator seeks to maximise GB consumer surplus only. While the regulator quantifies the producer surplus as well as the impact on other countries, these are not the primary drivers of the regulator's decision. Third, for economic tests in PJM, a project is selected if there is a benefit-cost ratio of greater than 1.25.

Figure 4-3: RIT-T guidelines



Source: AER (2010) RIT-T Guidance.

Figure 4-4: Quantification of market benefits



Source: AER (2010) RIT-T Guidance.

4.19 Based on the above, the RIT-T differs from international approaches in the following areas:

- The RIT-T includes the sum of consumer surplus, producer surplus and congestion rent in the CBA. This is a pure 'economic efficiency' approach, i.e. it accounts for the net economic welfare impact and ignores any distributional impacts. While this is similar to most jurisdictions, some jurisdictions (e.g. GB interconnectors) only consider consumer surplus and a portion of the congestion rent.[124] There is therefore precedent for departing from a strict economic efficiency approach towards a consumer-driven approach.
- The RIT-T allows for different discount rates to be applied to different investment options addressing the same need. This departs from other jurisdictions which tend to set a single rate based on either an average commercial rate or a social rate. However, we note that this issue is currently being considered by the AER as part of its review of the RIT-T application guidelines.[125] We also understand that, in practice, TNSPs have tended to use a single discount rate within each RIT-T; and

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[124] The RIT-T focuses on the costs of the transmission network development, but it does not explicitly distinguish between the price and cost effects. For example, an interconnector may have an impact on the dispatch costs as well as the price levels. While the marginal cost of generation may be a reasonable proxy for the price impacts, the two may sometimes diverge. To the extent that consumer benefits depend on the price effects (rather than cost effects), these may need to be assessed separately (see also ¶2.62).

[125] AER draft guidelines note that although RIT-T proponents have the flexibility to vary the discount rate between identified needs (rather than between different options to address a specific need), the proponents may, with a sound reason, depart from this approach and apply a different discount rate for a particular option. AER (2018) Draft Regulatory investment test for transmission application guidelines, July 2018, Section 3.4.2.

A distinction can also be made between the WACC (which reflects the cost of capital of a specific investment option) and the discount rate used to compare the present value of different options. The RIT-T does not, however, explicitly make this distinction. As noted above in ¶3.31, GB uses a mixed approach where all costs (including financing costs which are calculated based on a WACC) and benefits are discounted at the social discount rate.

- The RIT-T calculates the net benefits over modelling periods that should take into account the entire expected economic useful life of the asset, although the guidelines allow for flexibility of interpretation.[126] Different jurisdictions look at shorter time horizons when assessing transmission investment.

4.20 In theory, the design of an investment test should ensure that the optimal transmission need solutions are correctly identified. For example, if there are multiple possible solutions that deliver the same benefits (e.g. resolve a particular system need), then the investment test should be able to recognise this and identify the solution with the lowest cost.[127] If it were the case that a potential project delivered the benefits (i.e. met the identified system need) and was in fact the least cost solution, yet it failed to pass the relevant investment test (such as the RIT-T), then it would seem appropriate to consider implementing changes to the design of the test.

4.21 For example, a major strategic investment intended to meet a public policy objective rather than a reliability or economic need might not pass the equivalent of a RIT-T. In some jurisdictions in the US (PJM and NYISO), public policy needs are considered separately from reliability and economic needs. In addition, when assessing proposed public policy assets, some jurisdictions may consider the complementary effects of the asset on the rest of the system. In NYISO, the investment test for a public policy asset is a cost minimisation exercise by default. However, depending on the public policy requirement in question, additional metrics could be considered, including changes in production costs, emissions, congestion, or any additional metrics deemed necessary by the NYPSC.

126 AER draft guidelines note that modelling periods "*should take into account the size, complexity and expected life of the relevant credible option*" and that in some cases the modelling period may be 20 years or more. In addition, the guidelines provide for the inclusion of the terminal values in the analysis – which would therefore capture any value of the asset during the remaining lifetime beyond the modelling period itself. (AER (2018) Draft Regulatory investment test for transmission application guidelines, July 2018, Section 3.12).

127 The assessment is more complex in cases where different solutions provide different benefits – either in terms of the type need being resolved, or in terms of the time horizon.

4.22 This indicates that one option for the RIT-T might be to consider whether it should be augmented with complementary analyses that consider if a given asset helps meet a stated public policy objective, and any additional effects it may have on the system.[128]

4.23 There may also be some benefits related to transmission investments that are difficult to quantify. Option value of investments is one of these areas: as noted in FN71, the RIT-T does include option value as a potential market benefit, and the recent draft RIT-T application guidelines published by the AER in July 2018[129] provides further clarification as to how option value may be included in the assessment. Similarly, some transmission investments, particularly interconnectors, provide additional reliability and energy security by connecting two different states. This provides value in 'high impact, low probability' scenarios such as under outage conditions. Additionally, interconnectors allow more reserves to be shared across states thereby improving the way ancillary services are procured. Likewise, some transmission investments provide additional resilience to the networks.

4.24 While the RIT-T does not explicitly consider these hard-to-monetise benefits, other jurisdictions often evaluate them through a qualitative test. For example, Ofgem would consider the qualitative benefit of interconnectors' ability to improve security of supply as well as the quantitative benefit of contributing to ancillary services. Similarly, option value is assessed qualitatively (see ¶3.28). Likewise, ENTSO-E considers security of supply qualitatively under 'ordinary conditions', but also the technical resilience/system safety under increasingly "*extreme system conditions*".[130]

Suggestion for further analysis #2: Consider the pros and cons of restricting the evaluation criteria to consumer surplus, and potentially congestion rents, rather than social welfare measured by the change in total costs of production), and consider how these metrics could be used. In addition, continue to explore ways to value optionality and other material externalities.

128 Relatedly, consultation responses on the design of the ISP suggest the importance of an integrated and extensive plan. The ISP can then provide some inputs into the individual RIT-T tests, which can take into account location-specific factors such as a particular neighbouring interconnector or renewable energy zones.

129 AER (2018) Draft Regulatory investment test for transmission application guidelines, July 2018, Section 3.9.3 and Appendix A.9.

130 ENTSO-E (2015), Guideline for Cost Benefit Analysis of Grid Development Projects.

Suggestion for further analysis #3: Consider formalising the current practice of applying a single discount rate for all options assessed and consider whether the use of a social rate could be appropriate (particularly if the benefits are 'societal').

Suggestion for further analysis #4: Consider the most appropriate time horizon for the CBA (including the merits of fixed and variable time horizons).

c) Process and application of the investment test

4.25 The RIT-T is conducted by the individual TNSPs. This differs from investment tests in other jurisdictions which rely more heavily on an independent SO and/or regulator. In some cases the Government may also have a role to play – for example in the NYISO, the NYSPC identifies public policy needs for transmission investment (see ¶3.32).

4.26 AEMO's role in the RIT-T is largely administrative; it publishes the project specification consultation and project assessment draft reports and collects responses. It can also submit a consultation response to either of these reports. AEMO also provides some independent modelling assumptions that may be used in the RIT-T analysis by the individual TNSPs. The role of the AER in relation to the RIT-T in Australia is also mostly administrative: the regulator monitors the TNSPs' compliance with the RIT-T guidelines and resolves disputes (if any)[131] regarding the application of the RIT-T. However, the AER does not have any formal role in 'approving' the RIT-T outcomes and investment decisions and it also does not relate the outcome of the RIT-T investment decision to the regulated asset base on the TNSPs.

4.27 While we recognise that both AEMO and AER have a formal role in the application of the RIT-T, their responsibilities appear to be narrower in scope compared to the SOs and/or regulators in other jurisdictions.

4.28 As mentioned above in ¶4.18(2), the individual TNSP identifies the need and runs the actual cost-benefit analysis under the RIT-T. Credible solutions can be proposed by either the TNSP or third-parties. In the latter case, if a given third-party's solution is chosen as the preferred option, the TNSP will contract with the third-party to provide the service (this could include operation, construction, etc.), but the TNSP will retain the ultimate responsibility for meeting the identified need.

[131] The RIT-T's dispute resolution process is outlined below in ¶4.31 onwards.

4.29 There is no fixed timeframe for a RIT-T. On average, the actual test takes 17 months to complete, but this can range from 7 to 29 months. Moreover, the actual project may not be formally commissioned until much later.

Table 4-1: Timeframe information on completed RIT-Ts

Project	RIT-T period *(months)*	Approx. period from RIT-T to project start *(months)*
AEMO: Regional Victoria Thermal Capacity	18	21
AEMO: ElectraNet Heywood interconnector	21	36
ElectraNet: Dalrymple substation upgrade	7	36
Powerlink: Maintaining a reliable electricity supply to the Bowen Basin coal mining area	14	5
Powerlink, TransGrid: Development of the Queensland – NSW interconnector	29	n/a (do nothing option selected)
TransGrid: Powering Sydney's Future	13	56
Average	**17**	**31**

Source: AER (February 2018) Review of the RIT application guidelines, Table 6.

4.30 The length and duration of the RIT-T has been recently criticised by a number of parties in response to AEMO's Integrated System Plan Consultation. In particular, some respondents stressed that they consider the speed at which RIT-T proceeds to no longer be adequate in the current environment characterised by rapid renewables expansion.[132]

4.31 The RIT-T's dispute resolution process allows parties to challenge decisions made. Parties that can raise disputes include:

- registered and intending participants;
- the Australian Energy Market Commission ("AEMC");
- connection applicants (this would include generators);
- AEMO; and

132 ENA (March 2018) ISP Consultation Submission, pp 2; Hydro Tasmania (February 2018) ISP Consultation Submission, pp 5; Clean Energy Council (March 2018) ISP Consultation Submission, pp 2.

- interested parties (any party who, in AEMO's opinion, has identified itself as having an interest in network planning and development).

4.32 The resolution of these disputes can have the effect of delaying the transmission investment. In general, this delay is from 40 to 100 business days,[133] but this largely depends on the complexity of the issues under dispute. Because virtually any party can raise a dispute, those disadvantaged by any provisional RIT-T result may be perceived to have an incentive to intentionally delay or disrupt any RIT-T decision on transmission investment via this process.

4.33 These delays can significantly impact the transmission development process. For example, land access rights may expire in the time it takes to resolve the dispute, or elements of planning permissions may need to be renewed. This increases the risk for all TNSPs intending to deliver transmission investment, and could lead to a more conservative (or slow) transmission planning process than would be the case if the dispute resolution process was weaker.

Suggestion for further analysis #5: Explore expanded role for the SO and/or regulator, and explore alternative approaches to disputes resolution.

d) Addressing prevailing market failures

4.34 This section describes four potential market failures:

- information asymmetry;
- imperfect information;
- coordination failure; and
- misallocation of risks and rewards.

4.35 Each of these is assessed in turn below.

Information asymmetry

133 AER (September 2017) RIT-T updated application guidelines, pp 51, Figure 2.

4.36 As illustrated in ¶4.18(3) to ¶4.18(4), the RIT-T is highly prescriptive in terms of the costs and benefits that can and cannot be used in the assessment of credible options. This would appear to limit the extent to which TNSPs (or other proponents of credible options) can exploit their private information to their own advantage.[134] However, the RIT-T is slightly less prescriptive in the methodology for assigning probabilities to the reasonable scenarios.[135]

4.37 **Regulator and the SO.** Unlike in other jurisdictions, there are no explicit roles for AEMO or AER to mitigate the information asymmetry that may arise between TNSPs and the regulator (or between the TNSPs and third-parties), for example by verifying submissions by the TNSP as part of the RIT-T itself. Rather than 'testing' the TNSP analysis, the process appears to rely on the prescriptiveness of the RIT-T itself to ensure that the information presented by the RIT-T is accurate and reliable. For example, there is no "shadow" modelling of the cost-benefit analysis and no direct link between the costs assessed as part of the RIT-T and the costs included in the RAB of the TNSP. In addition, there is no ex-post cost monitoring of projects in place that would require the TNSP to adhere to the initial cost proposals. [136]

4.38 **Third-parties.** The RIT-T allows third-parties (including proponents of non-network solutions) to put forward proposals to resolve a particular system need, which the TNSP is required to assess provided that these proposals are 'credible'. In principle, this helps overcome some of the information asymmetry between the incumbent TNSP and third-party providers, but is subject to additional challenges as explained below in ¶4.41.

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134 TNSP's could be perceived to still be able to influence the outcome of a RIT-T towards a particular option by 'skewing' their estimates of the underlying parameters such as future demand growth, timings of new build / closure of generators or other features of the system.

135 See FN118.

136 Currently, all capex incurred by transmission businesses is included in the respective TNSP's RAB (as long as it does not breach a pre-set allowance), regardless of whether a RIT-T took place for said capital expenditure. This could allow TNSPs to earn revenue on assets whose costs have run over those identified in the RIT-T, or those they took unilateral action to build without running a RIT-T (even when one was required).

The COAG (February 2017) RIT-T Review (pp 30) notes that *"A project's costs can be rolled into a transmission network business' asset base even though business proceeded with the project without a RIT-T (and one was required) or where there is a substantial increase in the project costs identified in a RIT-T"*. Our understanding is that this includes situations where an increase in costs could have otherwise stopped the project from going ahead.

4.39 **Generators.** The RIT-T does not directly address the information asymmetry between TNSPs and generation developers. For example, a generator selecting a particular site for its new plant does not have a clear understanding of the costs that its siting decision may impose on the wider network due to the re-allocation of flows. Equally, a generator may not have sufficient certainty about whether it will eventually be connected to the network (e.g. if the transmission connection that is required does not pass the RIT-T) or whether it will be dispatched less than expected due to a contemporaneous improvement to the transmission system. This is not just a reflection of information asymmetry, but also of a lack of coordination, and is explored further in ¶4.44 onwards.

Imperfect information

4.40 The RIT-T uses a specific discounting approach, based on commercial cost of capital, to account for future uncertainty. The commercial discount rate is intended to be a reflection of the risk faced by the TNSP.[137]

4.41 However, the TNSP responsible for a particular RIT-T is in a position to attribute given percentage discount rates to third-party run network solutions which may affect their attractiveness. As explained in ¶4.18(6), the TNSP can evaluate different projects using different discount rates, which may potentially give it an inappropriate incentive to use a higher discount rate on solutions proposed by third-parties to reduce their net benefits. This concern has been raised in the AER's review of the NEM's regulatory investment tests in February 2018.[138]

4.42 The RIT-T sets out a specific process for the market benefits to be assessed over a range of reasonable scenarios and probabilities for each reasonable scenario. This allows the TNSPs to calculate an expected value of market benefits, to be compared to cost estimates. The process appears to be somewhat prescriptive relative to other jurisdictions (although certain elements of it, such as the probabilities, are subjectively determined) and provides limited discretion in terms of the scenario analysis.[139]

137 See ¶4.18(6).

138 AER (February 2018) Review of the application guidelines for the regulatory investment tests, Section 5.7, pp 37.

139 See ¶4.18(4)(iv)(b).

4.43 The RIT-T assesses individual projects in isolation. It does not have an explicit provision for considering multiple or combined projects, or the 'strategic' value of the investment. This has been an area of criticism recently raised by a number of parties.[140] In addition, the RIT-T guidelines for assessing and including the option value of particular investments have been subject to some criticism as well.[141]

Coordination failure

4.44 The RIT-T partly addresses this market failure insofar as interconnectors are included in the test and are therefore assessed in the same way as all other transmission investments. As part of this, a given TNSP is required to include the costs and benefits that relate to the entire NEM (rather than a particular state), which should therefore allow for benefits or costs accruing to neighbouring states to be included.

4.45 The test includes the consumer surplus, producer surplus and transmission congestion rent (see Figure 2-2 above), however transfers of surpluses from one party to the other cannot be included in the RIT-T's measure market benefits. As explained in ¶2.62, this means that the RIT-T effectively takes into account three specific components of welfare, namely areas 1+2+3 in Figure 2-2.

4.46 As a result, the costs and benefits (when including both the consumer and producer surplus) tend to partly (but not necessarily fully) cancel each other out. As a result, the RIT-T may deliver a different level of interconnector investment compared to other jurisdictions (e.g. only consumer surplus is considered in GB).[142]

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140 SnowyHydro believes that highly strategic transmission investments should bypass the RIT-T entirely, SnowyHydro (February 2018) ISP Consultation Submission, pp 11-12. Hydro Tasmania note that "the current regulatory tests have limitations that can inhibit future-focussed strategic investments", Hydro Tasmania (February 2018) ISP Consultation Submission, pp 8.

141 The COAG Report noted uncertainty among stakeholders as to how the option value of a project should be calculated, as it is not clearly explained in the AER RIT-T guidelines, COAG (Feb 2017) RIT-T Review, Section 3.6.1.

142 ENTSO-E considers the full socio-economic welfare, including consumer and producer surpluses and therefore is more similar (than GB is) to the RIT-T test.

4.47 The COAG Report has assessed whether the RIT-T may be inadequate for assessing and developing interconnector projects (noting that respondents highlighted the potential risk of lack of 'strategic oversight' and the incremental nature of investments). The COAG Report disagrees with this for a number of reasons:

- Firstly, even though the RIT-T is often applied on an incremental basis, nothing in the RIT-T specifically precludes coordination between two TNSPs to deliver interconnection investment. It points to ElectraNet's RIT-T in 2016 that considered four interconnector options as evidence of this.
- Secondly, the AEMC's last resort planning power allows it to require one or more TNSPs to apply a RIT-T to an interconnection project if it determines such an investment is required and other mechanisms have failed to provide it. According to the COAG Report, that it has yet to exercise this power suggests a sufficient level of interconnection in the NEM.[143]

4.48 The COAG Report thus found that, despite the potential difficulties with coordinating interconnector investment, that there are no practical barriers to net beneficial interconnection.[144]

4.49 However, the test features no explicit coordination with generators (especially renewable energy companies) and/or with gas transmission.

- The coordination with renewable generators[145] has been identified as a potential shortfall of the existing RIT-T and several parties have suggested that a more explicit coordination between renewable generators and TNSPs would be appropriate.[146]

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143 COAG (Feb 2017) RIT-T Review, Section 6.6.

144 Ibid.

145 Coordination with generators is also important if, for example, the problem is local voltage support, or having enough generation in a load pocket during a contingency.

146 CEC (March 2018) ISP Consultation Submission, pp 3; ENA (March 2018) ISP Consultation Submission, pp 4; Powerlink (February 2018) ISP Consultation Submission, pp 1.

- The coordination with gas networks has also been identified as a potential issue. Gas transport alternatives are currently not considered under the RIT-T, and TNSPs have no authority to direct gas pipeline investment, resulting in potentially inefficient investment being undertaken. In a hypothetical scenario where gas transmission would have been a more beneficial investment than a transmission line, the RIT-T would have produced an inefficient recommendation.[147]

Box 4-1: ERCOT, Texas – Competitive Renewable Energy Zones

By 2004, the Texas government recognised that a 'chicken and egg' problem had developed between wind development and transmission. TOs were unwilling to commit to investing in transmission lines without a commensurate commitment from wind developers to build new generation assets. Wind developers were similarly unwilling to commit to building new plants given the long lead time required to construct transmission lines. In response to this, the Public Utilities Commission of Texas ("PUCT"), the regulator, and the Electric Reliability Council of Texas ("ERCOT"), the ISO, began to develop Competitive Renewable Energy Zones ("CREZ") and a transmission plan to deliver the power generated from CREZ sites to customers. Based on its own studies, input from wind developers, and financial commitment from wind developers, the PUCT identified five zones in 2007 and began to develop optimal routes. This involved significant new transmission expansion investments spanning across western Texas where the REZ were located and eastern Texas where some of the load centres were. The project was completed in 2014, at USD 6.9bn and designed to serve c.18.5GW.

Financial commitment by generation developers to a given zone was measured by the amount of existing or planned renewable generation, and the amount of capacity represented by signed interconnection agreements. Alternatively, wind developers could declare their financial commitment to a given zone by posting deposits of between USD 10,000 to USD 15,000 per MW.

This was an example of proactive transmission investment; whereby renewable zones were sited and transmission lines committed before any physical generation plants were built. A critical element in this approach was the requirement for the developers to commit to the new generation build, which mitigated the risk of stranded transmission assets.

While this has spurred significant transmission investment, other

147 Productivity Commission (April 2013) Electricity Network Regulatory Frameworks Inquiry Report, Vol. 2, pp 650 – 651.

commentators have noted that customer bills have risen considerably as well,[148] with an uncertain balance of benefits between consumers and producers.

Misallocation of risks and rewards

4.50 The RIT-T serves primarily as a pure 'economic benefit' test, focusing on the total of consumer, producer and transmission costs and benefits, but with no consideration of any distributional effects of the test. As a result, the RIT-T also fails to provide practical insights as to how potential distributional impacts could be mitigated. In addition, while each state in the NEM has its own price zone, there is no nodal pricing within each zone (such as, for example, in some US markets). Finally, the costs and benefits quantified in the RIT-T are not linked to the regulated returns received by TNSPs.

4.51 This has several implications:

- First, since the test ignores distributional impacts of any transmission investment, it is exposed to the risk that those who see part of their welfare being transferred to another group (e.g. consumers to producers or vice versa) would strongly object to any investments that would adversely impact them. Such objections could be overcome through suitable compensating mechanisms (e.g. allocating the costs to the parties who benefit the most), but this does not feature in the RIT-T. As a result, the lack of mechanism for compensating adversely affected parties may therefore prevent socially beneficial investments from going ahead.
- Second, the lack of nodal pricing means that the investment can most often be only undertaken by the incumbent TOs. This is because third-parties would find it challenging to identify the benefits of intra-zonal investments (or to have the benefits allocated to them). For example, third-party developers would need to work out the benefits of congestion resolution in order to be able to articulate a workable proposition (if they can identify benefits, then they may still be incentivised to undertake the investment). In addition, third-party developers may not be able to develop intra-zonal projects insofar as they would not be able to be rewarded by being allocated the appropriate Financial Transmission Rights ("FTRs").

148 E&E News (2015) Rising costs in Texas challenge retail market, accessed at: https://www.eenews.net/stories/1060022490

- Third, as explained in FN136, TNSPs appear to be able, to a certain extent, to exceed the initial capital expenditure of a potential transmission investment. This is because they are not exposed to any ex-post monitoring or verification in case their costs exceed their original expectations, so long as their total capital expenditure does not exceed a pre-set allowance.

Suggestion for further analysis #6: Consider a separate transmission planning process and investment test for interconnectors between states.

Suggestion for further analysis #7: Consider different approaches to cost recovery (which may be applied differently for different asset types). This may be linked to the investment test as the economics of the investment might affect the cost recovery method.

5. Summary and conclusions

5.1 The following section summarises the main differences between the RIT-T and other international precedents, and reiterates previous suggestions for further analysis.

Table 5-1: Summary of international precedents and RIT-T

Parameter	International precedent	RIT-T	Suggestion for further analysis
A. Driver of transmission investment	Different asset types and proposed solutions for different needs assessed using separate tests.	All assets types for all needs evaluated using the same test.	**#1:** Explore whether investment tests for transmission networks in the NEM should distinguish between asset needs and/or asset types.

Parameter	International precedent	RIT-T	Suggestion for further analysis
B. Methodology of investment tests – benefits	In GB,[149] benefits often only include consumer surplus, while in the US, benefit metrics vary widely but typically include consumer and producer impact and reflect congestion costs (through nodal pricing). Externalities are typically only assessed qualitatively and play a secondary role.	Benefits measured include consumer surplus, producer surplus, and congestion rents, and explicitly exclude transfers of surplus and externalities. They are estimated over a range of reasonable scenarios.	**#2:** Consider the pros and cons of restricting the evaluation criteria to consumer surplus,[150] and potentially congestion rents, rather than social welfare,[151] and consider how these metrics could be used.[152] In addition, continue to explore ways to value optionality and other material externalities.
B. Methodology of investment tests – discount rate	In GB, a social discount rate is usually applied (though OFTOs use their own commercial discount rates), while in the US, a single weighted average of TO discount rates is used.	A commercial discount rate is applied on a project by project basis, and is chosen by the TNSP, with possible option specifications	**#3:** Consider formalising the current practice of applying a single discount rate for all options assessed and consider whether the use of a social rate could be appropriate (particularly if the benefits are 'societal').
B. Methodology of investment tests – time horizon	Time horizons in GB and the US tend to be fixed and shorter than the economic life of the asset.	Benefits and costs estimated over a non-fixed horizon that is intended to be the full useful life of the asset.	**#4:** Consider the most appropriate time horizon for the CBA (including the merits of fixed and variable time horizons).

149 The GB regulator has no *vires* over third-party countries – for example, for interconnector investments between GB and Europe, Ofgem may focus primarily on consumer surplus impact, while the European counterparty regulator may include other factors (e.g. overall social welfare).

150 Measured by the price impact on consumers.

151 Measured by the change in the total costs of production.

152 This would depend on the regulators' statutory obligations.

Parameter	International precedent	RIT-T	Suggestion for further analysis
C. Process and application of investment tests	In GB, both the SO and regulator have an active role; the regulator is the key decision maker in many investment tests. In the US, the SOs also have a more active role as key decision makers in the transmission planning process.	Both SO and regulator have a relatively passive role	**#5:** Explore expanded role for the SO and/or regulator, and explore alternative approaches to disputes resolution.
D. Addressing market failures – coordination	Interconnectors are treated differently from other transmission assets in all the case studies reviewed.	The RIT-T arguably disadvantages interconnectors by excluding transfers of surpluses in its CBA.	**#6:** Consider a separate transmission planning process and investment test for interconnectors between states.
D. Addressing market failures – misallocation of risks and rewards	GB tests link their results directly to the regulated return earned by TOs. In the US, a beneficiary-pays principle is adopted (although the application of this principle can be difficult)	The RIT-T is not explicitly linked to the regulated returns received by TNSPs. Allocation of benefits is limited due to the lack of location-based marginal prices.	**#7:** Consider different approaches to cost recovery (which may be applied differently for different asset types).

Appendix 1
Selected examples of transmission network investments

A1.1 This appendix describes selected examples of how interconnector transmission investments in Europe (NorNed, IFA and BritNed) and the US (CREZ) have performed in relation to the original expectations.

NorNed

A1.2 In 2008, the NorNed interconnector between Norway and the Netherlands came online with a maximum capacity of 700MW. The aim of the project was to improve the reliability of energy supply between Norway, where electricity is predominantly generated by hydropower plants, and the Netherlands, where energy is predominantly fossil-fuel based. There is a 50/50 cost and revenue sharing arrangement between the Dutch operator TenneT and the Norwegian operator Statnett.[153]

A1.3 The current flow on the interconnector is predominately from Norway to the Netherlands. The project cost approximately EUR 600 million and was expected to earn annual revenues of EUR 64 million. However, the first two months generated revenues of approximately EUR 50 million, far exceeding expectations.[154]

[153] Cigre, NorNed – World's longest power cable, accessed at https://library.e.abb.com/public/22d1dc6a2e72fa27c1257dea00357f41/NorNed%20HVDC%20link%20-%20Worlds%20longest%20power%20cable.pdf.

[154] Power Engineering International, NorNed: giving Europe's power trading a welcome boost, 1 December 2008, accessed at http://www.powerengineeringint.com/articles/print/volume-16/issue-10/features/norned-giving-europersquos-power-trading-a-welcome-boost.html.

IFA

A1.4 The IFA interconnector was commissioned in 1986 and is the only interconnector currently operating between GB and France.[155] It was one of the first examples where two markets with a price spread were connected to the benefit of both markets.

A1.5 The interconnector cost GBP 700 million, which was approximately half the cost of constructing an equivalent-capacity power station. Its development was justified on the basis that it was less costly and more efficient to source energy from France than it is to transport it the length of the UK.[156]

A1.6 IFA is an example of an interconnector project that has successfully recouped its initial investment costs and continued to generate benefits. The GB regulator, Ofgem, decided that when the project achieves NPV neutrality (i.e. when the upfront costs of the project have been fully recovered), positive cash flows are to be shared equally between consumers and National Grid Interconnector Limited (the SO). Ofgem determined that IFA achieved NPV neutrality on 31 March 2016, approximately 30 years after construction.[157]

BritNed

A1.7 BritNed is a direct current interconnector with a 1000MW capacity. It was one of the largest power transmission projects commissioned in Europe at the time of being constructed (operational since 2011), and was identified as a priority project for creating a trans-European energy network.

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155 Several new interconnectors (including ElecLink, FAB Link, Aquind and GridLink) are currently on the drawing board and could come online in the coming years.

156 London Business School, Cross Border Electricity Trading and Market Design: The England-France Interconnector, accessed at http://faculty.london.edu/mottaviani/IFA.pdf.

157 Ofgem, IFA Use of Revenue Framework, 22 August 2016, accessed at https://www.ofgem.gov.uk/system/files/docs/2016/08/publication_of_ifa_use_of_revenues_framework_20160822.pdf.

A1.8 Project costs and rates of return have been redacted by the European Commission for confidentiality reasons.[158] However, it is estimated that the project cost GBP 500 million.[159]

A1.9 BritNed is a commercial, open-access asset, meaning that its funding and operation is separated from National Grid's (GB) and TenneT's (Netherlands) regulated activities. Customers access interconnector capacity through auctions for defined capacity, flow direction, and time duration.[160]

A1.10 With respect to the allowed rate of return, for the first 10 years, if the internal rate of return is more than one percentage point higher than the initial estimated internal rate of return, BritNed must increase interconnector capacity until the initial rate of return is met, or pay additional profits equally to the transmission operators in the UK and Netherlands.[161]

A1.11 Although it is currently uncertain how profitable this interconnector may turn out to be over its lifetime, this mechanism has been designed by Ofgem to ensure that the interconnector produces a sufficient level of benefit to consumers in the form of lower prices by restricting the interconnector from significantly exceeding expected returns.

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158 European Commission, Exemption decision on the BritNed interconnector, accessed at https://ec.europa.eu/energy/sites/ener/files/documents/2007_britned_decision_en.pdf

159 Timera Energy, Interconnectors – a competitive source of new capacity for the UK power market, 9 June 2014, accessed at https://www.timera-energy.com/interconnectors-a-competitive-source-of-new-capacity-for-the-uk-power-market/

160 Power Engineering International, Building BritNed – the first power link between UK and the Netherlands, accessed at http://www.powerengineeringint.com/articles/print/volume-18/issue-6/features/building-britned-the-first-power-link-between-uk-and-the-netherlands.html

161 Ofgem, Amendment to the exemption order issued to BritNed Development Ltd under condition 12 of the electricity interconnector licence granted to BritNed in respect of the BritNed interconnector, accessed at https://www.ofgem.gov.uk/ofgem-publications/41228/britned-amended-exemption-order-pdf

CREZ

A1.12 In 2005, the PUCT, the regulator, and the Electric Reliability Council of Texas ("ERCOT"), the ISO, began to develop CREZ and a transmission plan to deliver the power generated from CREZ sites to customers. This was an example of proactive transmission investment, whereby renewable zones were sited and transmission lines committed before any physical generation plants were built. (See Box 4-1 for further details).

A1.13 As at 2017, Texas was on track to build 70% more wind capacity than originally planned. The project has delivered approximately USD 1.7 billion in annual electricity production cost savings, plus another USD 5 billion in economic development. With a service life of between 30 to 50 years, the benefits of the CREZ transmission lines are expected to greatly exceed their construction costs of USD 7 billion. [162]

Directlink

A1.14 Directlink[163] was the first interconnector built between the Queensland and New South Wales zones in the NEM. The interconnector was constructed under the justification that surplus capacity in New South Wales could address shortages in Queensland. However, due to changes in the supply and demand balances between the two zones, the energy has mainly flowed in the opposite direction.[164] Construction cost USD 70 million, and the interconnector began operating in 2000.[165]

[162] Clean Energy Grid (October 2017) Texas as a National Model for Bringing Clean Energy to the Grid, accessed at https://cleanenergygrid.org/texas-national-model-bringing-clean-energy-grid/.

[163] Also known as the Terranora Interconnector.

[164] AEMO, The Constraint Report 2009; AEMO, NEM Constraint Report 2016.

[165] Tamblyn, John, Feasibility of a second Tasmanian interconnector, April 2017.

A1.15 Originally, the interconnector earned revenues based on the spot price differential between the regions (i.e. congestion rent).[166] However, this proved unprofitable, and in 2005 the joint venture owners of the interconnector submitted an application for Directlink to become a regulated asset.[167] Revenues were initially guaranteed till 2015, and were again guaranteed for the 2015-2020 price control period.[168]

A1.16 Historically, the interconnector's performance has fallen short of the initial expectations, and both opex and capex have exceeded the regulatory allowance. For example, between 2011 and 2013, annual opex exceeded regulatory allowance by between AUD 0.75 million and AUD 1.3 million, primarily due to technical faults.[169]

A1.17 Directlink did not pass the regulatory test undertaken in the process of becoming a regulated asset, and it was found that the regulatory asset value should be less than the asset cost. Additionally, the interconnector suffered from several technical and reliability issues from 2000 to 2005.[170]

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166 Tamblyn, John, Feasibility of a second Tasmanian interconnector, April 2017.

167 Australian Energy Regulator, Directlink Joint Venturers' Application for Conversion and Revenue Cap: Decision, 3 March 2006.

168 Australian Energy Regulator, Final Decision: Directlink (transmission) 2015-20.

169 APA Group, Directlink Interconnector Revenue Proposal, 11 July 2014, accessed at https://www.aer.gov.au/system/files/Directlink%20presentation%20-%20AER%20public%20forum%20-%2010%20July%202014.pdf.

170 Australian Energy Regulator, Directlink Joint Venturers' Application for Conversion and Revenue Cap: Decision, 3 March 2006.

Appendix 2
International case studies on transmission investment tests

A2.1 This appendix details the full analysis of the international case studies on transmission investment tests and covers the following areas:

- Great Britain: SWW;
- Great Britain: NOA;
- Great Britain: Interconnectors;
- Great Britain: OFTOs;
- US: NYISO; and
- US: PJM.

Investment Test: Strategic Wider Works (SWW)

Key findings

- TO runs an initial cost-benefit analysis, which is closely reviewed by the regulator
- TO identifies need and brings case to regulator – potentially reduces time from need arising and regulator approval
- Frequent public consultations
- Regulator is a key decision maker, especially in approving and monitoring asset delivery and cost overruns
- Directly linked to approved regulated revenues
- Less prescriptive than the RIT-T in terms of benefits to be considered

Drivers of investment

- **Asset need:** Connect new generation; increase network capacity; increase electricity transfer capabilities across or within system boundaries. The SWW process is designed to help manage uncertainty around what infrastructure projects are required for the price control period as there was insufficient information at the time RIIO-T1 was published.
- **Asset type:** Onshore; delivery costs must exceed specific TO thresholds (Scottish Hydro Electric Transmission = £50mn; Scottish Power Transmission = £100mn; National Grid Electricity Transmission = £500mn); unbundling regulations limit non-transmission infrastructure by TOs.

Methodology

- **Methodology:** CBA – compared network reinforcement vs. no reinforcement for TO's preferred option and other tech viable options; assumption and input sensitivity testing.
- **Costs included:** Land, capex, expected maintenance, refurbishment, part and full replacement of assets, construction, pre-construction activities.
- **Benefits:** Environmental benefits, monetised costs and benefits to consumers and impacts on security of supply, justifications for any assumptions used. TO additionally considers the merits of different timings i.e. the benefits of delaying or accelerating the construction of the asset.
- **Investment criteria:** Expected project cost should be less than the cost to consumers in the case where there is no increase in network capacity; costs should not be recoverable under another provision; justified need for type of output (additional capacity/wider system benefits, verified using NETS SQSS).
- **Discount rate:** Regulated WACC of the specific entity undertaking the investment.

Process and application

- **Timeframe:** Duration: on average, 12-15 months; frequency: initiated by TO at any time.
- **3rd party involvement:** Stakeholders consulted at various assessment stages for a minimum of 8 weeks; TO seeks engagement and should show where stakeholders have informed TO's proposal and where their views differ.
- **Process:** TO identifies needs and addresses SWW requirements, creates project plan (using NETS SQSS – criteria and methodology for planning and operating GB Transmission System – to determine capability of transmission system that is adequately reliable, facilitates competition and is economic) and provides relevant information, including producing eligibility assessment, delivery strategy and supporting document.

  Cost-benefit and sensitivity analysis performed by the TO – closely reviewed by the regulator.

  Regulator runs: eligibility assessment; initial needs assessment (verify previous submissions, highlight unidentified issues, set indicative timeframe); competition assessment; public consultation (initial needs assessment); final needs assessment; consultation (final needs assessment); project assessment (in-depth on preferred option); decision letter.

Market failures

Information asymmetry:

- Public consultation at various project stages enables third party views to be reflected.
- Competitive procurement of a subset of asset types also possible (see next slide on NOA).
- Regulator reviews and performs analysis of preferred option based on TO proposals.

Imperfect information

- Regulator monitors delivery performance (including ex-ante assessments and ex-post information submissions).
- During construction TO reports annually on progress against delivery plan (completion date, expenditure).
- TO must provide evidence works meet SWW output specified in licence; if deviates from licence, assess specifics needs of case, including impact on consumers (failure to deliver specified output may constitute licence breach, Ofgem may impose financial penalties or consumer redress orders).

Coordination failure

- Coordination between TO (needs assessment) and SO (NOA), but not with generator developers or gas transmission.

Misallocation of risks and rewards

- If a SWW is identified, an adjustment to the TO's allowed revenue under RIIO-T1 is made.
- TOs submit risk sharing proposals, which are assessed by Regulator – should be an appropriate balance between TO and consumers.

Source: Ofgem (24 November 2017), Guidance on the Strategic Wider Works arrangements in the electricity transmission price control, RIIO-T1; Ofgem, (November 2013), Strategic Wider Works Factsheet

Investment Test: Network Options Assessment (NOA)

ofgem

Key findings

- SO responsible for running NOA with input from TOs. The process is relatively new (only three NOAs have been produced so far) and full impact remains to be tested
- SO runs single year least-worst regret analysis over asset's lifetime
- Lack of probability adjustments for scenarios implicitly treats all scenarios as equally likely. This can result in inappropriate investment recommendations (e.g. excessively conservative).
- SO's role is to make non-binding recommendations
- A recommendation via the NOA makes a TO's SWW application more likely to succeed

Drivers of investment

- **Asset need:** Identifies future reinforcement needs that are in the interests of consumers. Also promotes competition by determining suitability for third party delivery
- **Asset type:** Typically transmission assets only (EU unbundling regime prevents transmission owners from operating generation assets). However demand side services can be recommended to satisfy certain thermal and voltage constraints. NOA also comments on the total amount of future interconnection recommended (but not specific projects).

Methodology

- **Methodology:** Four Future Energy Scenarios (FES); CBA to compare forecast capital costs and monetised benefits over project's lifetime. The NOA process uses a BID3 model (this models dispatch functionality, treatment of hydro, foreign markets, weather-dependent renewables and generator constraints, among others).
- **Costs included:** Amortised present value of capital costs.
- **Benefits:** Present value of change in constraint costs. Inputs include: fuel price forecasts; carbon price; plant efficiencies, availabilities, bid and offer costs; renewable generation; demand data; maintenance outage patterns; system boundary capabilities and reinforcement incremental capabilities.
- **Investment criteria:** Single year least-worst regret (see worked example for the criteria and the selection of the preferred option); NETS SQSS (criteria and methodology for planning and operating GB Transmission System); SO compares against same criteria as SWW to determine eligibility
- **Discount rate:** HM Treasury's Social Time Preferential Rate (STPR) - 3.5% (real, pre-tax) (3.5% used since 2003)

Process and application

- **Timeframe:** Duration: set schedule for submissions; frequency: annual.
- **3rd party involvement:** Stakeholders given opportunity to give feedback and help develop sensitivities for testing need; consider role of third parties in developing asset.
- **Process:** SO produces NOA that identifies required new transmission projects (TO should use along with their own assessment). The SO's responsibilities are to: collect inputs from FES; identify future capability requirements; identify transmission options (SO collates potential solutions from TOs but may also add its own solutions); calculate operational costs; select recommended option; assess recommended option for competition; publish report.

Market failures

Information asymmetry:

- Public consultation at various project stages

Imperfect information

- Based on least worst regret (see worked example below). But this can produce false positives if a particular scenario is highly unlikely (the NOA currently has no probability adjustments for scenarios and implicitly treats all scenarios as equally likely).

Coordination failure

- NOA comments on the total amount of interconnection it believes is optimal, but not on specific projects.
- Helps the industry gain a common view of the direction of travel for the market.

Misallocation of risks and rewards

- Not a key issue, as output is non-binding recommendation

Worked example of NOA least-worst regret

- When comparing multiple assets, the SO calculates the constraint costs resulting from the construction of each option, under each scenario.
- The greatest constraint cost across the four scenarios (the worst regret) is identified for each option.
- The option with the least worst regret is therefore chosen.

Scenarios, regret values	Option A (£m)	Option B (£m)	Option C (£m)	Option D (£m)
Gone Green	17	127	136	153
Consumer Power	28	0	0	0
Slow Progression	9	12	12	22
No Progression	4	2	2	0
Worst regret	28	127	136	153

- Note that if the Gone Green (most ambitious) scenario is removed, there are very different "worst regrets". The scenario's inclusion is potentially driving overly conservative investment.

Source: National Grid (November 2017) NOA 3 2017-18 Methodology

Investment Test: Interconnectors – Cap & Floor

ofgem

Key findings

- Test for a single asset type (GB-Europe interconnectors)
- Test is initiated by developers and run by regulator
- Primary investment criterion applied by Ofgem is net GB (current and future) consumer benefit, with some consideration of wider impacts and non-monetisable qualitative benefits
- C&F level determined at Final Project Assessment stage, but subject to and ex-post 'Post Construction Review' to reflect changes in economic conditions / costs
- Long duration regime and floor support provide developer/operator more certainty (and reduce financing costs)
- Risks and rewards shared with consumers – if revenues exceed the cap, consumers earn the surplus; if revenues fall below the floor, consumers pay difference
- Less prescriptive than the RIT-T in terms of scenarios to be considered

Drivers of investment

- **Asset need:** Arbitrage revenues from connecting regions with different wholesale prices (i.e. GB and continental Europe), driven by net economic efficiency improvements (both extrinsic and intrinsic value of ICs is included)
- **Asset type:** Specifically for interconnectors between GB and continental Europe (unique and 'market leading' regime in Europe)

Methodology

- **Methodology:** Mechanistic approach to setting cap and floor ("C&F") levels; set C&F to recover asset costs and earn minimum floor return (based on cost of debt) and maximum return (based on cost of equity); cost assessment (before and after construction); CBA (including welfare) against plausible scenarios – which typically include Low/Medium/High scenarios and policy-specific scenarios (which may vary between individual assessments undertaken by Ofgem); qualitative evaluation of hard-to-monetise benefits.
- Two-step assessment undertaken by the regulator: Initial and Final Project Assessment (IPA and FPA respectively), with increasingly detailed analysis; complemented with ex-post reviews.
- **Costs included:** Present value of capex, opex, interest during construction, financing costs, tax, non-controllable (licence fees, decommissioning costs, grid costs), market related (relating to firmness). Use hybrid of projected costs (early stage) and actual costs (late stage). Costs of any necessary onshore reinforcement should also be included – this assessment is undertaken by the TO and may be a source of disagreement with the developer.
- **Benefits:** Developers expected to provide analysis that splits the benefits of the proposed interconnector between: consumers (electricity cost changes); interconnectors (capture regional electricity price differences); and generators in the UK and other key countries (electricity cost changes). In addition, the SO advises the regulator on the system impacts (costs/benefits) and value of ancillary services. For CBA, net present value of total GB consumer benefits (including system impacts) is used.
- **Investment criteria:** Ofgem assesses the investment cost-benefit analysis primarily from a GB net consumer welfare perspective. However, in its assessment Ofgem also includes total social welfare benefit (GB and overall project) and qualitative benefits analysis (e.g. security of supply, impact on competition, *etc.*)
- **Discount rate:** 3.5% (HM Treasury Social Time Preference Rate, real, pre-tax), or strong justification for different rate.

Process and application

- **Timeframe:** Process approx. 2-3 years for the full C&F process (e.g. Window 2 assessment started in October 2016, but no projects have reached FPA yet); regime is 25 years long
- **3rd party involvement:** Projects initiated and led by TOs or 3rd party developers; consultation after initial and final assessment stage (IPA and FPA)
- **Process:** Regulator first decides if C&F regime in consumer interest, and if so, opens application window (there have been 2 windows to date – one in 2014 and one in 2016, but no plans for a third window as yet). Developers submit applications, Ofgem carries out IPA and runs a consultation on its minded-to position. Subsequently, following developer's FPA submission, the regulator carries out the FPA; consults on its minded-to decision and, if the project is successful, grants a C&F regime to the developer. The regulator also carries out post-Construction review of costs before finalising the cap and floor levels.

  SO - Assists the regulator by publishing a system impact and ancillary services analysis on the proposed interconnectors – the cost-benefit implications for GB consumers are included in the regulator's overall assessments

Market failures

Information asymmetry:

- Developer to submit relevant info to regulator including its own CBA
- Ofgem runs its own independent CBA and also carries out PCR

Imperfect information

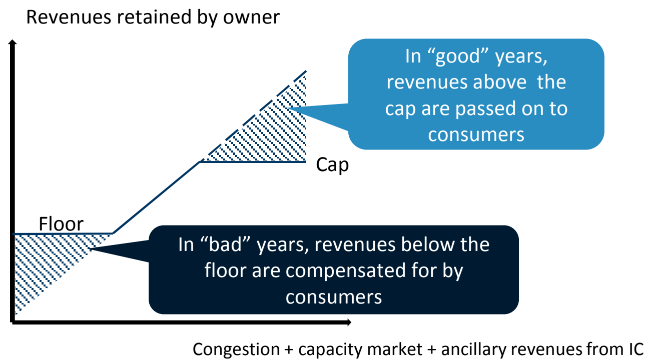
- Future uncertainty addressed through scenario-based modelling (including different future macro pathways and any relevant policy drivers – e.g. in GB, a key driver is carbon price support)
- Risk-sharing between developers and GB consumers through the structure of C&F. C&F level assessed at IPA and FPA (to provide visibility to developers and support financeability) and again at PCR (just before operation starts), to provide a degree of protection to consumers.
- C&F is a unique regime in GB designed specifically to facilitate investment in non-TO owned interconnectors – GB is at the forefront of this regulatory practice.

Coordination failure

- Overcomes risk of inadequate coordination between GB and neighbouring countries by allowing independent developers to propose and lead IC projects, and by allocating ownership rights over arbitrage revenues.
- Risk of over-investment in IC (or IC that adversely impacts domestic stakeholders) mitigated through regulator's reviews

Misallocation of risks and rewards

- Risks are shared between GB consumers and developer (consumers ultimately pay if operators unable to generate min floor revenues; but benefit if operator revenues exceed the cap)
- Floor payments critical to facilitate financeability of projects through debt (in exchange for which developers 'forgo' part of the upside by agreeing to the cap).
- In addition, C&F mechanism includes incentives for developers to maximise availability of the interconnector



FTI CONSULTING COMPASS LEXECON ENERGY

Sources: Cap and floor brochure, Ofgem; Proposal to roll out a cap and floor regime to near-term projects, Ofgem, May 2014; Decision to roll out a cap and floor regime to near-term electricity interconnectors, Ofgem, August 2014

Investment Test: Offshore Transmission Owners (OFTOs)

Key findings

- Test for a single asset type for a specific purpose (connect offshore wind farms to the GB onshore grid)
- Test based on cost-minimisation; the competition aspect focuses on financial cost
- Fully regulated investment with a fixed revenue stream
- Generation leads, and Ofgem is obligated to connect new assets – which reduces risks for generators, but potentially reduces efficiency (as offshore sites are likely to be selected without consideration of the connection costs)
- Test is run by regulator
- Less transparent than RIT-T; discount rate used is not disclosed to the public.

Drivers of investment

- **Asset need:** To connect new offshore wind farms, i.e. generation-led (offshore). Need to connect generators is taken as a valid 'justification' of the need (unlike RIT-T).
- **Asset type:** Transmission assets that link to offshore wind farms. Assets are privately developed and are awarded OFTO licences with fixed revenue streams. There are two types of licences – a generator-build licence where OFTO owns and operates the asset or an OFTO-build licence where the OFTO designs, constructs, owns and operates the asset (which has not yet been used).

Methodology

- **Methodology:** Ofgem designs the regulatory regime and tender process. Bidders offer their tender revenue stream based on the costs of performing the OFTO obligations and the costs of financing the investment. Ofgem undertakes a rigorous bid evaluation on the compliance of the bids, the non-financial submissions, the financial submissions and the revenue and underlying assumptions.
- **Costs included:** Design and construct costs, financing costs, O&M costs, decommissioning costs, insurance costs, SPV management costs, and transaction costs.
- **Benefits:** n/a – since the process is entirely driven by need to connect an offshore wind asset.
- **Investment criteria:** Three broad areas (but will not necessarily be limited to these criteria): economic and financial standing, technical capability, legal standing; Ofgem to publish details of evaluation criteria and process in documentation issued at each tender stage, submissions to be evaluated against the above broad criteria.
- **Discount rate:** Developer chooses, but must substantiate with evidence of target rate for such projects, or expected return (if lower). Ofgem published 6.83% (pre-tax, nominal) as an appropriate rate for offshore wind farm developers for 2017/18.

Process and application

- **Timeframe:** Each tender stage is approximately 6 months long (most recently, the 2nd tranche of 5th tender round took place in H1 2017). The sixth round is currently underway in 2018.
- **3rd party involvement:** During early tender rounds, bidders are not allowed to have direct contact with developers, developers are not allowed to know bidders' identities (contact only commences during preferred/successful bidder round); Ofgem to include third parties as necessary in bilateral meetings to monitor progress in preferred bidder stage.
- **Process:** Either (1) Generator build - transmission assets are built and transferred to the OFTO under comp tender; or (2) OFTO build - OFTO undertakes design and preliminary work prior to comp tender, then detailed design and construction. Developer can request start of a Tender Exercise, provide costings and relevant info, and may be required to pay regulators costs, assist pref/success bidder

  Bidders make submissions and respond when requested, provide all relevant info to developer/regulator, offers Tender Revenue Stream (TRS) in bid

  Regulator assesses costs, assumptions, may request extra info, calculates/sets Final Transfer Value, can adjust TRS to reflect 100% of Final Transfer Value, awards licence

  Tender stages: qualification of project; tender entry; pre-qualification stage; invitation to tender; best and final offer; preferred bidder; successful bidder; grant licence; financial close; asset transfer.

Market failures

Information asymmetry:

- Developers to provide Ofgem with relevant information, which the regulator assesses.
- Competitive process helps in getting developers to 'reveal' private information on efficient costs.

Imperfect information

- Ofgem reassesses costs at various tender stages
- Ofgem monitors progress of negotiations during preferred bidder stage
- Ofgem monitors developers until completion of Transfer Agreement

Coordination failure

- Does not specifically address coordination issues, as OFTOs reflect generation-led investment
- There is no risk that a potential wind farm would fail to be connected (due to OFTO of Last Resort provisions)

Misallocation of risks and rewards

- Bidders should not bear unnecessary costs or risks in Transfer Agreement
- Focus on allocation of financial risk

Sources: Offshore Electricity Transmission Tender Process Guidance Document, October 2016; Offshore Transmission – Updated Guidance for Cost Assessment, July 2017; Evaluation of OFTO Tender Round 2 and 3 Benefits, Cambridge Economic Policy, March 2016

Investment Test: New York Independent System Operator (NYISO)

Key findings

- Effectively 3 tests being run for different types of assets.
- For Reliability and Public Policy solutions, competition is encouraged in that market-based options are prioritised – regulated options are used as a 'last resort'.
- For Economic assets, decisions to build or not to build are made by those Load-Serving Entities who benefit from said assets, via a weighted voting system.
- ISO runs the test using input from TO proposed transmission plans (3rd party plans and plans suggested by NY Public Service Commission are also evaluated).
- Interregional planning carried out via agreements with neighbouring ISOs (for example, the ISO/RTO Planning Coordination agreement).
- In theory, costs of investment are recovered from parties in proportion to the benefits derived from the transmission asset. However applying this principle can be difficult and some methods have led to questionable outcomes.
- Variables to be flexed under the scenario analysis are more prescriptive than those under the RIT-T. However, unlike the RIT-T, scenario analysis is only undertaken when necessary.

Drivers of investment

- **Asset need:** Assets: Reliability Need; Economic (congestion); and Public Policy (any other Federal or New York State statute or regulation)
- **Asset type:** Assets can include non-transmission solutions (consideration of these is required by FERC Order 1000). Interregional assets (approved through a separate process) can also be included in the transmission plan. **Reliability and Public Policy:** Market-based or regulated; **Economic:** Market-based only.

	Reliability and Public Policy tests	Economic test
Scenario development	Base Case: Forecasts from the NYISO Gold Book used	Assumes a system that meets all Reliability Needs and takes as given the most recently identified preferred reliability solutions
Costs included	The present value of the sum of: capital costs; engineering and design; procurement; with expected variance of said cost estimates. Also considers the cost per MW	Revenue requirement - This includes: O&M; depreciation; taxes; and required return on capital.
Benefits	Largely a cost minimisation exercise. The following factors (which are not quantified) are also considered: operability and performance, availability of property rights, and schedule for project completion. Public policy assets may also consider, where relevant, any additional metrics specified specified by the NYPSC.	Present value of production cost reduction over 10 years. Also includes: estimated reductions in losses; LMP load costs, generator payments, ICAP costs, Ancillary Services costs, emission costs
Investment criteria	Meeting Reliability Criteria (set by NERC, NPCC, NYRSC); reduce congestion (Economic); and meeting Public Policy Requirements; proposed solutions evaluated on a comparable basis; provide an opportunity for competitive market-based solutions from third parties; coordinate with neighbouring regions	
Discount rate	n/a	Commercial – weighted average of the commercial costs of capital of the TOs. 2017: 7.0%; 2015: 6.8%; after tax, nominal rate.
Selection of preferred option	Market-based solutions ranked (according to cost-benefit metrics above). NYISO first attempts to meet the need with market-based solutions, and only chooses a regulated solution as a last resort, or if the regulated solution with the longest delivery schedule must be completed in less than 36 months.	Load Serving Entities (electricity utility companies, "LSEs") vote on project. Votes are weighted by the given LSE's share of benefits. Projects with more than 80% affirmative votes are built.

Process and application

- **Timeframe:** Once every 2 years
- **3rd party involvement:** Interregional planning conducted with NYISO neighbouring areas in the US (under the Northeastern ISO/RTO Planning Coordination Protocol) and some Canadian entities. This is run separately to the NYISO's planning process, but projects from the interregional planning phase can be included in the plans of individual regions. Any qualified interested party can propose solutions and participate in the planning process. Public sessions are held to disseminate information and updates.
- **Process:** TOs perform transmission studies that feed into SO planning process; TOs and any other qualified party may propose both market-based or regulated backstop (last resort) solutions; SO identifies needs (NYPSC identifies Public Policy asset needs), runs cost-benefit assessments and publishes chosen solutions. TOs may raise disputes with relevant committees within the ISO. Other parties may still raise complaints as per the Federal Power Act.

Market failures

Information asymmetry:

- ISO and TOs will make available all data necessary for interested parties to propose solutions, incl through multiple public information sessions
- General preference for market-based solutions helps deliver more efficient solutions (compared to a regulated outcome).

Imperfect information

- Any interested party (if qualified) can propose solutions and participate in the planning process
- Scenarios analysis developed and performed by the ISO when necessary – variables considered are stated to be: load forecast uncertainty; fuel prices; new resources; retirements; transmission network topology; and limitations imposed by proposed environmental legislation.

Coordination failure

- Studies undertaken by SO rather than by separate TOs.
- Requirement to consider non-transmission solutions.
- Results of Northeastern ISO/RTO Planning Coordination Protocol (for interregional assets) taken into account.
- Needs assessment for Reliability assets uses information from neighbouring zones.
- Impact of transmission projects on other Northeastern ISO/RTO regions will be identified – but NYISO does not bear the cost of required upgrades in another region.

Misallocation of risks and rewards

- Preference for market-based solutions aligns risks and rewards.
- Allocation of both voting rights and cost allocation to LSEs in proportion to benefits aligns risks and rewards for Economic projects.
- Use of results of CB study to determine voting shares and cost recovery assures alignment of benefits measure with transmission study results.
- FERC Order 1000 mandates that transmission cost allocation methods selected by ISOs must satisfy the following criteria:
  - Regional planning processes (of ISOs) must allocate transmission construction costs to entities roughly in proportion to benefit.
  - Those who do not benefit from transmission do not have to pay for it
  - Benefit-to-cost thresholds must not exclude projects with significant net benefits
  - No allocation of costs outside a region unless other region agrees
  - Transparency
  - Different methods can be applied to different types of transmission facilities

Sources: NYISO Tariff, NYISO Manual

Investment Test: PJM

Key findings

- PJM effectively runs two separate investment tests; one for each type of need. However they are interrelated in that a Reliability asset can be considered an Economic asset if it meets certain criteria.
- Competition is encouraged in that any interested party can propose to build transmission assets.
- For economic efficiency assets, consumer, producer, and power system impacts are taken into account (for 15 years) and benefits continue to be monitored (the SO can 'stop' a project if it considers it is no longer beneficial).
- Co-ordination between different regions is achieved by considering the outputs of the cross-regional planning processes into account.
- In theory, costs of investment are recovered from parties in proportion to the benefits derived from the transmission asset. However applying this principle can be difficult and some methods have led to questionable outcomes.

Drivers of investment

- **Asset need:** Distinction made between Reliability projects and Economic Benefit (congestion) projects. Public Policy projects documented but assessed under a different unrelated process.
- **Asset type:** All transmission facilities (excluding interregional assets) of 100kV and above and those below 100kV if they are under PJM's operational control (lowest US transmission voltage is 138kV). Assets can be both market-based or proposed by incumbent TOs. Assets can include non-transmission solutions (consideration of these is required by FERC Order 1000).

	Reliability test	Economic test
Methodology	Fundamental assumptions of load, generation and transmission forecasts produced by PJM. In addition, the SO develops a five year near-term reliability analysis.	
Costs included	Present value of the revenue requirement of the enhancement for the first 15 years of the asset's life. This includes: O&M; depreciation; taxes; and required return on capital of the asset.	
Benefits	"Benefits" not explicitly quantified, only whether the proposed asset is technically capable of meeting the reliability requirement.	Present value for the first 15 years of the asset's life. Includes changes in costs of: fuel; O&M; and emissions of the dispatched resources in the PJM region. Also includes expected effects on congestion; load and LMPs in each zone; expected effects on PJM's capacity market; and price effects on energy bought from and sold to regions outside PJM.
Investment criteria	Maintaining the reliability of the electricity system in an economic and environmentally acceptable manner; Supporting competition – by providing an opportunity for a wide variety of stakeholders to be involved; Maintain and enhance the wholesale market's efficiency and operational performance.	
Discount rate	n/a	Commercial – weighted average of the commercial costs of capital of the TOs. 2017: 7.4%; 2016: 7.4%; 2015: 7.8%; after tax, nominal.
Selection of preferred option	For **Reliability assets**, PJM first evaluates if the proposed solution meets the identified need, then evaluates the cost. It then assesses if any of the proposed solutions meet the criteria for an Economic asset if they are enhanced or expanded (see below). An **Economic asset** is constructed if its benefit-cost ratio is above 1.25. If a Reliability need is not met by a Reliability solution that has been upgraded to an Economic asset, then PJM will simply select the most cost effective solution.	

Process and application

- **Timeframe:** 18 month overlapping cycle beginning every September and extending to the following February. A new cycle begins before the previous one ends.
- **3rd party involvement:** Transmission Expansion Advisory Committee (TEAC), the Subregional RTEP Committee and the PJM Planning Committee (PC) forums take an active role in the planning. TEAC membership is open to all: Transmission Customers; transmission providers; electric utility regulators; and any other interested parties.
- **Process:** PJM's annual Regional Transmission Expansion Plan; Test performed by the SO; For economic efficiency projects, the SO annually monitors costs and benefits. If there are any changes for a given project, the SO will review if the project should be continued. TOs may raise disputes with relevant committees within the ISO. Other parties may still raise complaints as per the Federal Power Act.

Market failures

Information asymmetry:

- Numerous committees are set-up to contribute to the process. Representatives for virtually any interested party can be members of these committees.

Imperfect information

- Discounting future benefits and costs
- Scenario analyses run by the ISO when necessary. Less transparent than RIT-T in terms of which specific modelling inputs the SO varies for different scenarios.

Coordination failure

- Benefits (in terms of costs of electricity purchased from and sales to) related to regions outside of PJM can be quantified if SO decides it is relevant
- Transmission planning considers the terms of multiple agreements between PJM and other neighbouring ISOs
- To the extent that transmission projects are approved under agreements with other ISOs, PJM may share these revenues with other ISOs, to be distributed to applicable TOs.

Misallocation of risks and rewards

- FERC Order 1000 mandates that transmission cost allocation methods selected by ISOs must satisfy the following criteria:
  - Regional planning processes (of ISOs) must allocate transmission construction costs to entities roughly in proportion to benefit.
  - Those who do not benefit from transmission do not have to pay for it
  - Benefit-to-cost thresholds must not exclude projects with significant net benefits
  - No allocation of costs outside a region unless other region agrees
  - Transparency
  - Different methods can be applied to different types of transmission facilities

Public policy assets

- Public policy assets are assessed via the State Agreement Approach.
- Entities authorised by their respective states, individually or jointly, may agree voluntarily to be responsible for all allocation of costs of a proposed transmission investment that addresses some public policy requirement.
- These assets are included in the PJM RTEP, and are not assessed by PJM.

Sources: PJM Tariff – Attachment Y; PJM Manual

Relationship between two GB processes that govern the development of onshore transmission investments: SWW and NOA

Project Development Framework		1 Scenario development	2 Identify system needs	3 Identify and select solution: Coordinating / developing options	Identify and select solution: Identify Solution	Identify and select solution: Select optimal solution
SWW	Regulator		**Ofgem** reviews whether the TO is eligible for assessment under SWW arrangements. It also considers if the project is suitable for competitive tender, and whether the need for the proposed reinforcement is well justified.			**Ofgem** makes the final approval decision and publishes it. The TO's regulated revenue is adjusted as required
SWW	SO	**NG SO** develops the Future Energy Scenarios as a basis for scenario analysis		**NG SO** runs a revised cost benefit analysis after the TO to reflect any changes to the project or generation background.		
SWW	TO		**TO** identifies need, proposes solutions (including a preferred solution) and runs an initial cost benefit analysis. The TO is ultimately responsible for all submissions of evidence to Ofgem. The TO arguably has a higher chance of success if its proposed project has been recommended by the NOA.			
NOA	SO	**NG SO** develops the Future Energy Scenarios as a basis for scenario analysis	**NG SO** identifies needs. For each electricity network boundary, the future capability required under each scenario is calculated	**NG SO** describes high level options to meet the identified needs. These are broad descriptions of assets (e.g. AC OHL cable, HVDC cable, etc.) and potential routes.		**NG SO** uses least-worst regret methodology to rank various options. This information is fed into the SWW.
NOA	TO				**SO** collates the **TO** submissions and may add its own solutions. **TOs**, in response to these high level options, develop more detailed options and submit them to the **SO.**	Note that the NG SO's NOA recommendations are not binding.