REVIEW

Australian Energy Market Commission

STAFF PAPER: INTERNATIONAL TRANSMISSION PLANNING ARRANGEMENTS

Transmission Frameworks Review

22 February 2013

Reference: EPR0019
Staff Paper: International Transmission Planning Arrangements

Inquiries

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

E: aemc@aemc.gov.au
T: (02) 8296 7800
F: (02) 8296 7899

Reference: EPR0019

Citation

AEMC 2013 , Transmission Frameworks Review, Staff Paper: International Transmission Planning Arrangements, 22 February 2013, Sydney

About the AEMC

The Council of Australian Governments (COAG), through its then Ministerial Council on Energy (MCE), established the Australian Energy Market Commission (AEMC) in July 2005. In June 2011, COAG established the Standing Council on Energy and Resources (SCER) to replace the MCE. The AEMC has two main functions. We make and amend the national electricity, gas and energy retail rules, and we conduct independent reviews of the energy markets for the SCER.

Contents

1 Introduction

1.1 Purpose of this document

This document provides a summary of transmission planning arrangements in a variety of international electricity markets. This paper has been produced in response to a number of stakeholders commenting on these arrangements throughout the Transmission Frameworks Review (TFR), which is currently being conducted by the Australian Energy Market Commission (AEMC).

This paper provides a brief review of transmission planning arrangements in North America, New Zealand, Great Britain, Ireland and other European countries. We note that the focus of this report is on the institutional arrangements in these markets, including:

- the body responsible for undertaking transmission planning;
- the body responsible for making investment decisions;
- the ownership arrangements of these bodies; and
- whether there is any regulatory oversight of these bodies.

Importantly, this paper is not intended to provide a comprehensive review of international transmission planning arrangements. Instead, it is intended to provide a brief overview of these markets to interested stakeholders.

1.2 Acknowledgements

This Information Paper has been prepared by the staff of the Australian Energy Market Commission (AEMC) to inform interested stakeholders as part of the TFR. It does not necessarily represent the views of the Commission or any individual Commissioner.

We note that NERA Economic Consulting (NERA) was previously retained to undertake a detailed review of the transmission planning arrangements in PJM, New York, California and Alberta.[1] For these markets, the paper draws out the most pertinent details of NERA's review of these markets.

1.3 Structure of this document

The remainder of this document is structured as follows:

- Section 2 provides a summary of transmission planning arrangements applying internationally;

1 See NERA Economic Consulting, Planning Arrangements for Electricity Transmission Networks: An International Review, 12 April 2012.

- Section 3 provides an overview of transmission planning arrangements in North American markets including PJM, New York, California, Alberta and Texas. It also provides an overview of a recent policy reform (FERC Order 1000) in North America;
- Section 4 provides an overview of transmission planning arrangements in New Zealand;
- Section 5 provides an overview of transmission planning arrangements in Great Britain;
- Section 6 provides an overview of transmission planning arrangements in Germany;
- Section 7 provides an overview of transmission planning arrangements in Ireland; and
- Section 8 provides an overview of recent changes to transmission planning directives in Europe.

Appendix A sets out a brief description of PJM's recent FERC 1000 filing.

2 Summary of International Transmission Planning Arrangements

We have undertaken this review in order to provide information to interested stakeholders on the institutional arrangements for transmission planning in international markets. In this section, we briefly set out an overview of these arrangements.

North American markets generally have the feature of having a not-for-profit planner. These not-for-profit planners are responsible for both investment planning, and investment decision making in the relevant market. However, they do *not* own the transmission assets. In North American markets transmission assets are owned by multiple parties who do not make investment decisions, or undertake planning (aside from local issues). These parties are also vertically integrated ie transmission owners typically also own generation.

The not-for-profit planner who is primarily responsible for undertaking transmission investment decisions is also subject to regulatory oversight either by the Federal Energy Regulatory Commission (FERC), or a local regulator.[2] This oversight occurs through the regulator applying "rate of return" or "cost of service" regulation. Under this form of regulation, the rate of return that a network can earn on its assets is set by the regulator. Individual investments are then approved by the regulator in order for the tariff level to be set.

In contrast to North America, most European countries (as well as New Zealand) have adopted transmission planning arrangements where planning responsibilities are aligned with ownership of the network, ie investment planning and decision making is undertaken by the transmission owner. These transmission owners are typically for profit companies – even if they are owned by the government. Moreover, most European countries only have *one* transmission owner, which does not also own generation. This follows recent European Directives to unbundle vertically integrated generation and transmission businesses (ie in contrast to the transmission owners in North America). We note that in Ireland responsibilities are split between the transmission system operator (TSO) and the transmission asset owner (TAO). In Ireland, the TSO is responsible for transmission planning and investments associated with planning up to the detailed design stage.

Like North America, TSOs in all European countries (as well as New Zealand) face some form of oversight of planning by the regulator – being either direct approval of plans and/or projects by the regulator, or indirect approval of plans and/or projects through economic regulation. Most European countries are subject to "incentive" regulation via a price- or revenue-cap. Under incentive regulation, the regulator sets a revenue allowance (based in part on forward looking plans). Individual projects are

2 The exception is the Tennessee Valley Authority, which is discussed in further detail in Table 1 below. This "self regulates", ie the Board of Directors sets its tariffs.

not approved since transmission owners are incentivised to build and plan the network to reduce costs in order to keep some of the allowance.

Table 2.1 provides a summary of the planning arrangements in the various jurisdictions considered, with a focus on who is responsible for "planning" and "investment decision making". It also includes a brief comparison of the planning approach in the relevant country, and the planning approach in Australia. The arrangements in the majority of the NEM are most similar to those seen in European countries (and New Zealand), where the TNSP owns, operates and plans the network. TNSPs in the NEM have also been unbundled into separate, for-profit entities. The arrangements in Victoria are most similar to those in North America. However, we note the Victorian arrangements are different given that there is no regulatory oversight of AEMO, and rate of return regulation does not apply in Australia.

Table 2.1 Summary of International Transmission Planning Arrangements

Country/Region	Transmission System Operator (TSO)	Transmission Owner (TO)	Transmission Planning	Transmission Investment Decision Making	Regulatory Oversight	Comparison with Australia
Australia						
Australia (Qld, NSW, SA, Tas) (termed "majority of NEM" for remainder of table)	AEMO – not-for-profit organisation	4 TNSPs: • Powerlink - government owned; • TransGrid - government owned; • ElectraNet - privately owned; and • Transend - government owned.	The TNSP is responsible for transmission planning. AEMO provides a strategic long-term view of the transmission network, through production of the National Transmission Network Development Plan (NTNDP) TNSPs must take into account the NTNDP in their transmission planning.	The TNSP is responsible for transmission investment decision making.	There is no direct link between planning and revenue regulation as administered by the AER. However, planning documents inform the regulatory process, where the AER sets a revenue allowance. The AER monitors TNSP compliance in producing planning documents according to the Rules.	na
Australia (Victoria)	AEMO - not-for-profit organisation	SP AusNet – privately owned (Note: other TNSPs do own some small sections of the network where the augmentation	AEMO is responsible for augmentation planning of the transmission network. SP AusNet is responsible for replacement and	AEMO is responsible for augmentation transmission investment decision making. AEMO does not	There is no regulatory oversight of AEMO. SP AusNet is subject to regulatory oversight for replacement and refurbishment decision making by the AER.	na

Country/Region	Transmission System Operator (TSO)	Transmission Owner (TO)	Transmission Planning	Transmission Investment Decision Making	Regulatory Oversight	Comparison with Australia
		was undertaken contestably)	refurbishment planning of the transmission network.	own any network infrastructure and procures from third parties that own and maintain the assets. SP AusNet is responsible for replacement and refurbishment decision making.		
North America						
PJM	PJM Interconnection – independent not-for-profit organisation. The Board must be independent.	Approximately 14 TOs who are full voting members of PJM – all for-profit companies.	PJM is primarily responsible for transmission planning TOs can plan to address "local" issues.	PJM is primarily responsible for transmission investment decision making TOs can make decisions on investments to address "local" issues.	FERC approves the planning process. FERC approves the individual investments identified by PJM, due to its role in approving PJM's tariff. As part of the tariff approval process, the investment must be shown to have been identified through the FERC-approved planning process.	These are similar arrangements to Victoria. However, unlike in Victoria, in PJM FERC provides regulatory oversight of decisions by the not-for-profit TSO. FERC also approves the planning process.
New York	NYISO – independent	Eight TOs in NYISO – all	Both NYISO and TOs are responsible for	NYISO is responsible for	FERC approves the planning process.	These are similar arrangements to

Country/Region	Transmission System Operator (TSO)	Transmission Owner (TO)	Transmission Planning	Transmission Investment Decision Making	Regulatory Oversight	Comparison with Australia
	not-for-profit corporation, governed by an independent Board of Directors.	for-profit companies.	transmission planning. TOs develop detailed plans for local systems, using applicable reliability criteria. TOs also propose "market based" projects. Using these plans/proposals as inputs, NYISO then undertakes the Comprehensive System Planning Process (CSPP) for the region, which lists both the reliability and market based projects needed.	investment decision making through its production of the CSPP. In most cases, NYISO does not expressly direct or determine upgrades, but it will if required (ie for reliability reasons as a backstop). TOs can make decisions on investments to address "local" issues.	FERC approves the individual investments identified by NYISO, due to its role in approving NYISO's tariff. As part of the tariff approval process, the investment must be shown to have been identified through the FERC approved planning process.	Victoria. However, unlike in Victoria, in NY FERC provides regulatory oversight of decisions by the not-for-profit TSO. FERC also approves the planning process.
California	CAISO – non-profit public benefit corporation, governed by an independent Board of Governors	TOs – three own around 80% of the total transmission capacity of CAISO. All are for-profit companies.	CAISO is primarily responsible for transmission planning through undertaking the annual Transmission Planning Process (TPP). TOs provide planning	CAISO is solely responsible for transmission investment decision making.	FERC approves the planning process. FERC approves the individual investments identified by CAISO, due to its role in approving CAISO's tariff.	These are similar arrangements to Victoria. However, unlike in Victoria, in CAISO FERC provides regulatory oversight of decisions by the

Country/Region	Transmission System Operator (TSO)	Transmission Owner (TO)	Transmission Planning	Transmission Investment Decision Making	Regulatory Oversight	Comparison with Australia
			studies as input to the TPP.		As part of the tariff approval process, the investment must be shown to have been identified through the FERC approved planning process	not-for-profit TSO. FERC also approves the planning process.
Texas	ERCOT, governed by a Board of Directors including representatives from industry segments. The Board also includes the Public Utilities Commissioner of Texas as a non-voting member.	Large number of transmission service providers (TSPs) – some of these are municipal owned utilities	ERCOT is primarily responsible for transmission planning. Transmission planning for "local" transmission projects is undertaken by TSPs.	ERCOT is also primarily responsible for investment making decisions. Investment decisions for "local" transmission projects are undertaken by TSPs. Most projects require approval from a Regional Planning Group, comprised of industry representatives.	ERCOT is regulated by the Public Utilities Commission of Texas (PUCT) and the Texas Legislative. Unlike other US markets, it is not subject to FERC regulation. Each TSP files a tariff for a transmission service to establish its rates and other terms and conditions. PUCT regulates TSPs.	These are similar arrangements to Victoria. However, unlike in Victoria, in Texas PUCT provides regulatory oversight of decisions by the not-for-profit TSO. Industry representatives also have a role in approving specific investments.
Alberta	AESO – not-for-profit entity, governed by an independent	Six transmission facility owners, each located in a distinct service area – all for-profit	AESO has the sole responsibility for planning Alberta's transmission system by producing the long term plan. Following on	AESO and Alberta Utilities Commission (AUC) have joint responsibility for making investment decisions. AESO	See previous column. TFOs are entitled to recover the costs of transmission investments in an	This is a similar arrangement to Victoria; however, in Alberta AUC provides regulatory oversight of AESO. This does not

Country/Region	Transmission System Operator (TSO)	Transmission Owner (TO)	Transmission Planning	Transmission Investment Decision Making	Regulatory Oversight	Comparison with Australia
	Board	companies	from this plan, there is a specific planning process that develops a Need Identification Document (NID) for each investment.	applies to the AUC for approval of the NID. Once the AUC approves the NID, the AESO directly assigns the project to a TO according to service area. The TO will then file an application with the AUC for approval of the transmission facilities.	AESO tariff. AESO develops and administers the transmission tariff. The tariff is then approved by AUC.	occur in Victoria. Further, analogies can be drawn between the NID and the RIT-T in Australia. However, in Alberta the NID must be approved by the regulator; whereas in Australia this does not occur.
Bonneville Power Administration (Pacific Northwest of US)	Bonneville Power Administration (BPA) is a federal not-for-profit agency that is part of the US Department of Energy. It is self-funded and covers it costs by selling its products and services at costs. It was formed to sell power produced by federal dams. It sells power at a wholesale level to local, vertically integrated utilities/local distribution utilities. However, it also operates an extension transmission grid.		BPA is responsible for transmission planning. It has a two year planning process, that includes the development of a ten year plan. The process includes a significant amount of public consultation that allows input into and comments on the Plan.	BPA is responsible for making investment decisions.	Since BPA is a public agency it is exempt from general regulation by FERC. However, since 1996 BPA has filed tariffs with FERC under voluntary provisions. Therefore, FERC approves the planning process, as well as the individual investments identified by BPA, due to its role in approving BPA's tariff. BPA	The structure of the transmission market is similar to the majority of the NEM (ie the transmission owner undertakes both planning and decisions). However, BPA is a federal not-for-profit agency. Further, BPA is subject to "rate of return" regulation as applied by FERC, as opposed to "CPI-X"

Country/Region	Transmission System Operator (TSO)	Transmission Owner (TO)	Transmission Planning	Transmission Investment Decision Making	Regulatory Oversight	Comparison with Australia
					therefore considers FERC policy and adheres to FERC standards.	regulation as applied by the AER in Australia.
Tennessee Valley Authority (TVA)	Tennessee Valley Authority (TVA) is a not-for-profit federally owned corporation. TVA is governed by a Board of Directors, who are appointed by the President of the United States based on advice from the Senate. It was formed to sell power produced by federal dams. It sells power at a wholesale level to local, vertically integrated utilities/local distribution utilities. However, it also operates a transmission grid.		TVA is responsible for undertaking transmission planning. This includes the development of a ten year plan.	TVA is responsible for making investment decisions.	Since TVA is a public agency it is exempt from regulation by FERC. It falls outside FERC's general regulatory authority, including economic regulation. TVA produces a tariff agreement, which can be generally be considered to adhere to FERC policy/standards. As set out in its governing legislation TVA must set rates to recover various costs (operation, maintenance and administration of the power system, tax equivalents, debt services, repayments to US Treasury, and an appropriate margin).	The structure of the transmission market is similar to the majority of the NEM (ie the transmission owner undertakes both planning and decisions). However, TVA is a federal not-for-profit agency. Further, TVA is not subject to any economic regulation since it is a public agency. This could be considered similar to the arrangements in Victoria.

Country/Region	Transmission System Operator (TSO)	Transmission Owner (TO)	Transmission Planning	Transmission Investment Decision Making	Regulatory Oversight	Comparison with Australia
					The Board of Directors have sole responsibility for establishing tariff rates (ie it is self-regulating). These are not subject to judicial review or to review/approval by any state or federal regulatory body. As noted above TVA is not subject to the full jurisdiction of powers that FERC exercises. However, FERC does have some regulatory authority over TVA activities including: • TVA must comply with certain FERC approved reliability standards; • TVA can be ordered to interconnect its transmission facilities with others (provided certain requirements are	

Country/Region	Transmission System Operator (TSO)	Transmission Owner (TO)	Transmission Planning	Transmission Investment Decision Making	Regulatory Oversight	Comparison with Australia
					met); and • TVA can be ordered to transmit power (provided certain conditions are met). TVA has elected to implement various FERC orders on a voluntary basis, to the extent that these are consistent with TVA's obligations under its founding legislation.	
New Zealand						
New Zealand	Transpower – state owned enterprise ie owned by the NZ govt but operates as a private business		Transpower is responsible for transmission planning.	Transpower is also responsible for investment decision making. For "major capex" Transpower must apply the Grid Investment Test (GIT). The Commerce Commission must then approve "major capex" investments	The Commerce Commission approves a "base capex" revenue allowance in Transpower's determination. Revenue for "major capex" is approved on a case by case basis, with a lump sum amount approved.	These arrangements are similar to the majority of the NEM. The GIT is very similar to the RIT-T that is applied in Australia. However, the primary difference is that the Commerce Commission specifically scrutinises individual investments for "major capex", and

Country/Region	Transmission System Operator (TSO)	Transmission Owner (TO)	Transmission Planning	Transmission Investment Decision Making	Regulatory Oversight	Comparison with Australia
				and costs.		approves revenue on a project by project basis. In Australia all revenue is simply provided for in a revenue allowance.
Great Britain and Ireland						
Great Britain	National Grid Electricity Transmission (NGET)	Three TOs: NGET; Scottish Hydro Electric Transmission System; Scottish Power Transmission Limited – all there are for-profit companies	Transmission planning is undertaken by the three TOs in coordination. NGET develops planning assumptions to be used in the planning. NGET develops and maintains a separate plan – the NGET Investment Plan that sets out the proposed changes to its transmission system that are likely to have a material effect on any TOs plan or offshore TOs transmission system. This must be developed in	Investment decision making is the responsibility of each TO.	Key investment decisions are made during the price control process, undertaken by Ofgem. Ofgem approves a capital expenditure allowance with this not linked to specific investment projects. Ofgem does not undertake any scrutiny of individual investments. Ofgem also approves revenue drivers, which allow the revenue allowance to automatically adjust in response to changes in demand and/or firm	This is very similar to the transmission planning process that occurs within the majority of the NEM. However, NGET provides planning assumptions to be used in planning. It also develops and maintains a NGET Investment Plan – typically this reflects individual TOs plans. The regulation oversight and type of regulation is the same as that within the NEM. However, the revenue drivers circumvent the need for contingent projects as in the NEM,

Country/Region	Transmission System Operator (TSO)	Transmission Owner (TO)	Transmission Planning	Transmission Investment Decision Making	Regulatory Oversight	Comparison with Australia
			consultation with the TOs and generally reflects the individual TOs plans.		access levels.	since businesses have revenue automatically adjusted.
Ireland	EirGrid – owned by the Irish government	ESB Networks	EirGrid is responsible for transmission planning.	EirGrid is also responsible for transmission investment decisions, up until the point of detailed network design. ESB Networks is responsible for the detailed network planning, procurement and construction	Economic regulation is undertaken by the Commission for Energy Regulation, which sets out the transmission revenue that can be collected from customers. This is distributed between EirGrid and ESB Networks in accordance with infrastructure agreements.	This is more similar to the arrangements in Victoria. Here, the TSO undertakes planning and investment decisions for the TAO. However, EirGrid is a for-profit company (not a not-for-profit like AEMO). Further, in Ireland there is regulatory oversight of EirGrid; whereas in Victoria there is not.
Europe						
Germany	Four TSOs who are also TOs that all have distinct service areas: Amprion, EnBW Transportnetze AG, TenneT TSO GmbH and 50Hertz Transmission – all are for-profit businesses		Each TO is responsible for transmission planning in its region. The four TOs have also recently been required to jointly produce a 10 year Electricity Network	Each TO is responsible for investment decision making in its region.	TOs are subject to revenue regulation from the regulator. The jointly prepared network development plan will be examined and assessed by the Federal Network	This is similar to the structure in the majority of the NEM where different TNSPs have different regions that they plan/own/operate. However, in Germany the "strategic" joint

Country/Region	Transmission System Operator (TSO)	Transmission Owner (TO)	Transmission Planning	Transmission Investment Decision Making	Regulatory Oversight	Comparison with Australia
			Development Plan annually.		Agency, which will then be incorporated into legislation by the Parliament.	plan (similar to the NTNDP in Australia) is prepared jointly by the TOs, as opposed to by a separate party.
Belgium	Elia System Operator SA – publicly listed company		Elia is responsible for transmission planning and produces a number of plans setting out projects it plans to carry out, including a Federal plan. This covers investment at the Federal level and highest voltage level. It is produced every three years, and covers a 10 year period. This is approved by the Minister for Energy. Additionally, several regional plans covering investment in different regional areas. These cover lower voltage levels, and most plans must be approved by	Elia is responsible for investment decision making. It implements the plans following the request of the government authority.	The Federal regulator provides advice/comments on the Federal plan. Regional regulators provide advice/comments on regional plans. Elia is also subject to economic regulation at a Federal level.	This is similar to the majority of the NEM where the TO is a for-profit company and is responsible for planning and investment decisions. Economic regulation and oversight is similar to the majority of the NEM. However, in Belgium regulators provide comment/advice on regional plans. This can be considered similar to AEMO's role in South Australia (and proposed to be rolled out NEM wide in the Second Interim Report for TFR)

Country/Region	Transmission System Operator (TSO)	Transmission Owner (TO)	Transmission Planning	Transmission Investment Decision Making	Regulatory Oversight	Comparison with Australia
			regional governments.			
Croatia	Hrvatska elektroprivreda (HEP) – 100% state owned		HEP is responsible for transmission planning, and produces network development plans. HEP assess possible investments according to economic criterion – although this has not been defined by the Grid Code.	HEP is responsible for investment decision making.	The regulator must approve network development plans. HEP is also subject to economic regulation.	This is similar to the majority of the NEM, where the TO is a for-profit company who is responsible for planning and investment decisions. However, here regulators approve transmission plans. In Australia there is no direct link between revenue regulation and planning.
Denmark	Energinet.dk - 100% state owned – the Board is appointed by the Minister, but must be independent		Energinet.dk is responsible for transmission planning, and produces a national transmission development plan. This is produced in accordance with its transmission code.	Energinet.dk has the responsibility for transmission investment decision making.	Energinet.dk is subject to economic regulation from the regulator, with an annual revenue cap being set.	This is similar to the majority of the NEM, where the TO is a for-profit company who is responsible for planning and investment decisions. Further, TOs are subject to indirect approval of their planning process through their economic

Country/Region	Transmission System Operator (TSO)	Transmission Owner (TO)	Transmission Planning	Transmission Investment Decision Making	Regulatory Oversight	Comparison with Australia
						regulation.
Estonia	Elering – publicly limited company		The Ministry of Economic Affairs and Communications prepares an electricity development plan. This is developed in coordination with Elering.	The Cabinet of Ministers of the Republic of Estonia must approve the development plan.	Elering is subject to economic regulation from the regulator.	This is similar to the majority of the NEM, where the TO is a for-profit company who is responsible for planning and investment decisions. Further, TOs are subject to indirect approval of their planning process through their economic regulation.
Finland	Fingrid - Partially state owned (53.1%) and partially private owned (46.9%) company		Fingrid is responsible for transmission planning, and develops its national transmission development plan. The plan is developed in accordance with the transmission code.	Fingrid is responsible for investment decision making.	Fingrid is subject to economic regulation from the regulator.	This is similar to the majority of the NEM, where the TO is a for-profit company who is responsible for planning and investment decisions. Further, TOs are subject to indirect approval of their planning process through their economic regulation.

Country/Region	Transmission System Operator (TSO)	Transmission Owner (TO)	Transmission Planning	Transmission Investment Decision Making	Regulatory Oversight	Comparison with Australia
France	Reseau de Transport d'Electricite (RTE) - Wholly owned subsidiary of the partially public owned Electricite de France		RTE is responsible for transmission planning, and so develops a network development plan.	RTE is responsible for transmission investment decision making, with this overseen by the regulator – the Commission for Energy Regulation (CRE). Overseen by the Commission for Energy Regulation	The network development plan is approved by the regulator – CRE. CRE also approves the annual investment programme of RTE.	This is similar to the majority of the NEM, where the TO is a for-profit company who is responsible for planning and investment decisions. However, here regulators approve transmission plans. In Australia there is no direct link between revenue regulation and planning.
Netherlands	TenneT B.V – state owned		TenneT B.V is responsible for transmission planning.	TenneT B.V is responsible for investment decision making.	TenneT B.V is subject to economic regulation. The regulator approves annual electricity tariffs, which includes an amount to recover costs associated with transmission investments.	This is similar to the majority of the NEM, where the TO is a for-profit company who is responsible for planning and investment decisions. Further, TOs are subject to indirect approval of their planning process through their economic regulation.

Country/Region	Transmission System Operator (TSO)	Transmission Owner (TO)	Transmission Planning	Transmission Investment Decision Making	Regulatory Oversight	Comparison with Australia
Iceland	Landsnet – publicly listed company		Landsnet is responsible for transmission planning. It produces a grid plan outlining system development projects.	Landsnet is responsible for transmission investment decision making.	Landsnet is subject to economic regulation by the regulator.	This is similar to the majority of the NEM, where the TO is a for-profit company who is responsible for planning and investment decisions. Further, TOs are subject to indirect approval of their planning process through their economic regulation
Italy	Terna S.p.A. - Rete Elettrica Nazionale - Publicly listed company – with some shareholdings indirectly being the Italian government		Terna is responsible for transmission planning, and produces a grid plan outlining all transmission system development projects.	Terma is responsible for transmission investment decision making.	Development activities and plans are verified for compliance by the relevant government authorities.	This is similar to the majority of the NEM, where the TO is a for-profit company who is responsible for planning and investment decisions. Similarly to Australia, development activities and plans are verified for compliance by the regulator.
Norway	Statnett - 100% state owned public company		Statnett and the regional grid company	Statnett is responsible for	Transmission plans developed by Statnett	This is similar to the majority of the NEM,

Country/Region	Transmission System Operator (TSO)	Transmission Owner (TO)	Transmission Planning	Transmission Investment Decision Making	Regulatory Oversight	Comparison with Australia
			are responsible for planning the transmission system. Statnett develops its national development plan in accordance with its transmission code.	transmission investment decision making.	are approved by the regulator. The regulator (Norwegian Water Resources and Energy Directorate) determines an income cap for Statnett.	where the TO is a for-profit company who is responsible for planning and investment decisions. However, here regulators approve transmission plans. In Australia there is no direct link between revenue regulation and planning.
Poland	PSE-Operator SA – 100% state owned		PSE is responsible for transmission planning, and produces a Development Plan covering the upcoming 15 year period.	PSE is responsible for investment decision making.	PSE is subject to economic regulation by the regulator.	This is similar to the majority of the NEM, where the TO is a for-profit company who is responsible for planning and investment decisions. Further, TOs are subject to indirect approval of their planning process through their economic regulation
Romania	Transelectrica - Publicly traded company, with 90% of shares held by		Transelectricia responsible for transmission planning,	Transelectria is responsible for transmission	The regulatory authority approves transmission plans. Transelectria is	This is similar to the majority of the NEM, where the TO is a

Country/Region	Transmission System Operator (TSO)	Transmission Owner (TO)	Transmission Planning	Transmission Investment Decision Making	Regulatory Oversight	Comparison with Australia
	the government		and prepares long term plans of transmission development.	investment decisions.	also subject to economic regulation from the regulator.	for-profit company who is responsible for planning and investment decisions. However, here regulators approve transmission plans. In Australia there is no direct link between revenue regulation and planning.
Slovenia	Elektro-Slovenija, d.o.o. – state owned company		Elektro-Slovenija is responsible for transmission planning, and prepares long term plans of transmission development.	Elektro-Slovenija is responsible for transmission investment decision making.	The network development plans have to be approved by the regulatory authority. Elektro-Slovenija is also subject to economic oversight.	This is similar to the majority of the NEM, where the TO is a for-profit company who is responsible for planning and investment decisions. However, here regulators approve transmission plans. In Australia there is no direct link between revenue regulation and planning.
Sweden	Svenska Kraftnät – state owned company		Svenska Kraftnat is responsible for transmission planning,	Svenska Kraftnat is responsible for investment decision	Svenska Kraftnat is subject to economic	This is similar to the majority of the NEM, where the TO is a

Country/Region	Transmission System Operator (TSO)	Transmission Owner (TO)	Transmission Planning	Transmission Investment Decision Making	Regulatory Oversight	Comparison with Australia
			and prepares its transmission development plan.	making.	regulation. The regulator undertakes an annual review of the tariffs, which are based on capex and opex activities.	for-profit company who is responsible for planning and investment decisions. Further, TOs are subject to indirect approval of their planning process through their economic regulation

3 North American markets

This section provides a summary of transmission planning arrangements in a variety of North American markets. We note that NERA Economic Consulting (NERA) was previously engaged to undertake a review of PJM, New York, California and Alberta.[3] However, Texas was not included in this review and accordingly is discussed in more detail below.

The Federal Energy Regulatory Commission (FERC) has recently implemented reforms to transmission planning and cost allocation (in FERC Order 1000). A brief overview of these reforms is provided at the end of this section.

3.1 PJM

Transmission planning in PJM[4] is primarily undertaken by the local Regional Transmission Organisation (RTO) – PJM Interconnection (PJM).

PJM is an independent not-for-profit organisation. It has a two tier governance structure comprising an independent board and members committee. The Board must be independent ie have no affiliation with PJM market participants. Members of PJM include transmission owners (TOs) within the PJM service territory. By belonging to PJM they have assigned the primary regional transmission planning and investment decision responsibilities to PJM, and have committed to implement PJM’s plans.

PJM is therefore primarily responsible for transmission planning. It undertakes a Regional Transmission Expansion Planning (RTEP) process. This process has been approved by the FERC.[5] The RTEP process is a "top down" planning approach since it assesses transmission needs from a larger regional perspective. The RTEP is approved by the PJM Board.

PJM is also primarily responsible for transmission investment decision making. It instructs TOs to undertake the selected transmission investment as set out in the RTEP. Allocation of projects to TOs is based on the TOs service area. However, the TO assumes the rights and responsibilities associated with ownership, maintenance and cost recovery eg undertaking the siting decision.[6]

We note that TOs can plan and make decisions on investments to address local issues. However, if the costs of these are to be recovered by transmission tariffs, then these

---

3 NERA Economic Consulting, Planning Arrangements for Electricity Transmission Networks: An International Review, 12 April 2012 (hereafter "NERA report").

4 PJM comprises all of parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virgina, West Virgina and the District of Columbia.

5 FERC is the national energy regulator for the United States.

6 Siting decisions are approved by the PUC.

must also be approved by FERC (and potentially the state Public Utilities Commission (PUC)[7]).

FERC approves the individual investments identified by PJM, due to its role in approving PJM's tariff. As part of the tariff approval process, the investment must be shown to have been identified through the FERC approved planning process. Approved transmission costs are added to the rate base, and collected via the transmission tariff charged by PJM. PJM then passes this through to the TOs.

3.2 New York

Transmission planning in New York is primarily undertaken by the New York Independent System Operator (NYISO).

NYISO is an independent not-for-profit corporation, governed by a 10 member Board of Directors that are required to be independent. Board members are appointed through the NYISO stakeholder process in which representatives from each market sector recommend potential directors to the Board.

Both NYISO and TOs are responsible for transmission planning. TOs develop detailed plans for their local systems, using the applicable reliability criteria. Using these plans as inputs, the NYISO then undertakes the Comprehensive System Planning Process (CSPP) – a market based approach for transmission planning, with provisions to identify backstop reliability projects. As such, this is a "bottom up" approach to planning. This process has been approved by FERC.

NYISO and TOs are responsible for investment decision making. TOs propose projects (as set out above), as solicited by the NYISO in the CSPP process. NYISO then relies on "market" forces to determine what projects go ahead, by evaluating and monitoring the reliability of the system and any prospective changes to it. In most cases NYISO does not expressly direct or determine upgrades, but it will if required (ie for reliability purposes as a backstop).

Similarly to PJM, FERC approves the individual investments identified by NYISO due to its role in approving the tariff. As part of the tariff approval process, NYISO needs to show that investment is necessary to comply with the relevant standard, and that it has been identified following the FERC approved planning process. NYISO charges customers a transmission tariff, and then passes the revenue through to the TOs.

3.3 California

Transmission planning in California is undertaken by the California Independent System Operator (CAISO).

---

7 State PUCs are the state-level regulators of electric utilities in the United States. State regulation is historically distinguished from federal regulation in the United States by whether it relates to inter-state or within state activities. Transmission, which is largely an inter-state activity, is mostly regulated by FERC.

CAISO is a non-profit public benefit corporation. It is governed by a Board of Governors, which are required to be independent. In order to select Governors, a Board Nominee Review Committee is established comprising stakeholders from different members of CAISO. The Committee then develops recommendations for Governors, with these then nominated by the governor of California and confirmed by the Senate.

CAISO is primarily responsible for transmission planning. CAISO identifies, evaluates and approves new transmission facilities through its annual Transmission Planning Process (TPP). This planning process has been approved by FERC. However, TOs provide planning studies as input to the TPP. CAISO utilises these studies to produce the TPP. The TPP report must be approved by the CAISO Board of Governors.

CAISO is solely responsible for transmission investment decision making. As part of the TPP process, TOs submit "proposals" for projects identified in the TPP. All reliability driven investments are simply directed to specific TOs by CAISO. For economically driven or policy driven investments, CAISO assesses these on the basis of proposals submitted. CAISO does have the ability to undertake a competitive solicitation process for projects – however, this has not been utilised as yet. The TOs are responsible for building, owning and financing upgrades located within its territory, following CAISO's direction.

Similarly to PJM and New York, FERC approves the individual investments identified by CAISO due to its role in approving the tariff. CAISO charges customers a transmission tariff, which is then passed through to the respective TOs who build the transmission.

3.4 Alberta

Transmission planning in Alberta is undertaken by the Alberta Electric System Operator (AESO). This is a not-for-profit entity, governed by an independent Board. Members to the Board of the AESO are ultimately appointed by the Minister. This follows recommendations that stem from the current Board.

AESO has the sole responsibility for planning Alberta's transmission system. It develops a long term plan assessing the need for transmission projects. Following on from this plan, there is a specific planning process that develops a Need Identification Document (NID) for each investment. This evaluates investment options (similar to the RIT-T in Australia).

AESO applies to the Alberta Utilities Commission (AUC) for approval of the NID.[8] That is, AESO and AUC have the responsibility for investment decisions. Once the AUC approves the NID, the AESO directly assigns the project to a TO according to service area. The TO will then file an application with the AUC for approval of the transmission facilities. Transmission Facility Owners (TFOs) are not responsible for any transmission system planning.

8 The AUC does not approve the long term plan.

In 2010, AESO filed an application with the AUC for approval of a competitive solicitation process for critical transmission infrastructure (CTI).[9] The application was required under the Electric Statues Amendment Act in 2008, but has not yet been approved. The first projects proposed to be assigned in a competitive manner will be two single-circuit 500 kV transmission lines in 2017.

TFOs are entitled to recover the costs of transmission investments in an AESO tariff. AESO develops and administers the transmission tariff. This tariff is approved by the AUC (provided that the AUC considers the expenditure to be prudent and reasonable) and is charged to all transmission customers.

3.5 Texas

The major parties involved in transmission planning in Texas are:[10]

- the Electricity Reliability Council of Texas (ERCOT) – the Independent System Operator for the region. ERCOT covers the majority of Texas, but not all:
  - ERCOT is governed by a Board of Directors including the representatives from industry segments ie the Board is not independent. The Board also includes the Public Utilities Commissioner of Texas – however, this is a non-voting member;
- the Regional Planning Group (RPG) – led by ERCOT and is a non-voting, consensus body that reviews and comments on proposed projects. Membership is open to all market participants, transmission and distribution service providers, Public Utility Commission of Texas (PUCT) staff and other stakeholders;
- Transmission Service Providers (TSPs); and
- Public Utilities Commission of Texas (PUCT) – the state agency that regulates the state's electric and telecommunications utilities.

Unlike other US markets discussed previously, ERCOT is not subject to FERC regulation because it is not synchronised to the interstate transmission grid.

9 These are defined as projects that are: interties, to serve areas of renewable energy, a double circuit transmission facility that is designed to be energized at a nominal voltage of 240 kV, designed to be energized at a voltage in excess of 240 kV, or in the opinion of the Lieutenant Governor in Council, critical to ensure the safe, reliable and economic operation of the interconnected electric system.

10 The information in this section is largely drawn from the following websites: Electricity Reliability Council of Texas (www.ercot.com); and the Public Utility Commission of Texas (www.puc.texas.gov).

3.5.1 Transmission planning

ERCOT is the transmission planning coordinator for the region. Planning is undertaken for the both "bulk transmission system" and the "local transmission system". These are discussed in further detail below.

Planning of the Bulk Transmission System

ERCOT is responsible for planning the bulk transmission system. In summary, the planning of the bulk transmission system occurs as follows:

- ERCOT develops an annual plan (the Electric System Constraints and Needs report) that assesses transmission needs over a five-year horizon:
  - This assesses those investments needed to maintain the reliability of the network, and those with economic benefits;
- Projects identified are classified into one of four "tiers". Each tier is defined so that projects with a similar cost and impact on reliability/the ERCOT market are grouped into the same tier:
  - The tier sets out the level of review to which the projects in the Tier are subject. This is summarised in Table 3.1 below. Note that transmission investments associated with generator interconnection process are covered in a separate procedure.[11]

11 Projects identified through this process and that are regional in nature may be reviewed through the RPG Project Review Process upon recommendation by the TSP or ERCOT, subject to the confidentiality provisions of the generation interconnection procedure. ERCOT staff will perform an independent economic analysis of the transmission projects expected to cost more than $25m. This analysis is undertaken for informational purposes – no ERCOT endorsement is provided.

Table 3.1 "Tiers" of Transmission investments in Texas

	Definition	Review required	Approval
Tier 1	All projects with an estimated capital of $50m or greater	• RPG review and comment – RPG acceptance follows successful resolution of comments received during the comment period; • ERCOT independent review; • ERCOT Board of Directors endorsement	An endorsement letter is sent to the designated TSP for the project, the project submitter (if different to the designated TSP) and the PUCT. A copy is sent to the RPG.
Tier 2	All projects with estimated capital costs less than $50m not requiring a Certificate of Convenience and Necessity (CCN)	• RPG review and comment; • ERCOT independent review	
Tier 3	All projects with estimated capital costs between $15m and $50m not requiring a CCN	• RPG review and comment	RPG acceptance letter is sent to the designated TSP for the project
Tier 4	Small system upgrades whose estimated capital cost is less than or equal to $15m, and that do not require a CCN.[12]	No review required	na

Upon completion of the necessary approvals, ERCOT designates recommended transmission projects to providers. The default TSPs will be those that own the end points of the new projects. Those TSPs can agree to provide, or delegate the new facilities.

12 This also includes certain "neutral projects" - the addition of or upgrades to radial transmission lines; the addition of equipment that does not affect the transfer capability of a line; repair and replacement in kind projects; projects that are directly associated with the interconnection of new generation; and the addition of static reactive devices.

If a designated TSP agrees to provide a project and the TSP does not diligently pursue the project in a manner that will meet the required in-service date, then upon concurrence of the ERCOT Board of Directors, ERCOT will solicit interest from TSPs through the RPG and designate an alternative TSP to provide the asset.

The TSP then plans, constructs, operates and maintains the facilities. ERCOT also assesses transmission system adequacy on the longer term (ie up to 20 years) on an annual basis through the ERCOT Long-Term System Assessment (LTSA):

- in even numbered years, the LTSA is undertaken; and
- in odd numbered years, ERCOT reviews previous LTSAs in light of current system conditions, assumptions or expectations.

The LTSA is produced by ERCOT in coordination with the RPG.

Planning of the Local Transmission System

TSPs plan and make investment decisions for the local transmission system. ERCOT's role in relation to "local" transmission projects is limited to supervising and coordinating the planning activities of TSPs.

3.5.2 Economic regulation

ERCOT's budget and fees is regulated by the PUCT, with oversight from the Texas Legislature. Unlike other US markets, it is not subject to FERC regulation.

Each TSP files a tariff for a transmission service to establish its rates and other terms and conditions. PUCT regulates TSPs and approves the rates they are allowed to charge. The economic regulation operates in a similar manner to FERC in other states.

3.5.3 ERCOT governance

ERCOT is governed by a Board of Directors that comprises:

- five unaffiliated members;
- the ERCOT CEO;
- three representatives of consumers;
- six market participants; and
- the chair of the PUC (non-voting member).

The Board is therefore not fully independent.

3.5.4 Competitive Renewable Energy Zones

In 2005 a Renewable Energy Program was established, which directed the PUC to identify Competitive Renewable Energy Zones (CREZs). The PUC selected the CREZ transmission plan (CTP) from four proposed scenarios provided by ERCOT in 2008. The CTP designated five CREZs, and also designated the transmission projects to be constructed that would deliver wind energy to Texas consumers.

In 2008 the PUC undertook a transmission service provider selection process, with 21 entities submitting initial expressions of interest. 14 entities were assigned responsibility for specific projects identified in the CTP. TSPs were required to submit a proposal for a transmission project to the PUC, who issued a certificate of convenience and necessity (CCN) if the application is approved. The PUC selected entities based on several factors including the expected capabilities to finance, licence, construct, operate and maintain the facilities in the most beneficial and cost-effective manner.

3.6 FERC Order 1000

In 2011, FERC issued Order 1000 "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities".[13]The main reforms in this Rule are detailed below, and focus on reforms to: planning, cost allocation and right of first refusal.

3.6.1 Planning reforms

Each public utility transmission provider must participate in a regional transmission planning process to produce a regional transmission plan. This plan must satisfy the transmission planning principles of Order No. 890.[14] The regional provisions do not require any Independent System Operators (ISOs) or Regional Transmission Operators (RTOs) to significantly change their planning activities within a region. However, some minor modifications may be required. ISOs must have made compliance filings in relation to this reform by 11 October 2012.

Neighbouring transmission public utility transmission providers must coordinate in inter-regional transmission planning. This will assess whether there are more efficient or cost-effective solutions to transmission needs. At the time of the reform, most ISOs/RTOs did not have currently have processes in place in relation to this. It was therefore likely that this would require significant changes. ISOs/RTOs are currently engaging with each other in order to review the changes they will need to implement

13 For further information please see the FERC website – http://www.ferc.gov/industries/electric/indus-act/trans-plan.asp. We note this was also considered in the NERA report.

14 Order No. 890 implemented reforms to prevent undue discrimination and preference in transmission service. It requires public utility transmission providers to participate in open transmission planning processes at the local and regional level.

this requirement, and so meet the requirement to comply with these requirements by 11 April 2013.

Transmission planning processes (both local and regional) must consider projects to address public policy needs created by state/federal laws and regulations. Each public utility transmission provider must establish procedures to identify needs driven by these requirements, and evaluate proposed solutions.

This is seen as providing further opportunities to approve and fund more transmission projects associated with renewable resources. This will allow public benefits associated with these policies to be included in economic analysis of potential projects. However, how these public benefits are to be measured is not included in the Rule. ISOs/RTOs must have had complied with this by 11 October 2012.

3.6.2 Cost allocation

Public utility transmission providers must put in place a common method of allocating the costs of new transmission facilities selected in the regional transmission plan. Moreover, public utility transmission providers must also put in place a common method of allocating the costs of new transmission facilities selected in the inter-regional transmission plans.

These cost allocation methodologies may be different. However, the method must satisfy six principles as set out in the Rule:

- costs allocated must be at “least roughly commensurate” with estimated benefits;
- those not receiving benefits cannot be allocated costs involuntarily;
- if benefits to cost ratio thresholds are used, they cannot be greater than 1.25 unless it is justified by the region and approved by FERC;
- there can be no allocation of costs outside a region, unless the other region agrees;
- there must be transparency in the cost allocation method and identification of beneficiaries; and
- different cost allocation methods can apply to different types of transmission investments.

Most regions served by an RTO/ISO have cost allocation methodologies that address many of the principles contained in the Rule. However, some incremental changes may be required. ISOs must have made compliance filings in relation to this reform by October 11 2012.

However, most ISOs/RTOs do not have inter-regional cost allocation processes in place. It is likely that this will require significant changes. Currently, ISOs/RTOs are engaging with each other in order to review the changes they will need to implement this requirement, and so comply with inter-regional requirements by 11 April 2013.

3.6.3 Right of refusal

Previously in some regions in markets governed by FERC, incumbent TOs had a right of first refusal (ROFR) to build transmission facilities. This is where the incumbent had the right to construct, own and propose cost recovery for any new project that is a) located within its service territory; and b) approved for inclusion in the regional plan.

This ROFR applied only to those projects selected in regional plans for the purposes of cost allocation, ie those projects that affect the bulk transmission system. Following this Rule, the ROFR must be removed from tariffs. This does not require removal of a ROFR for those projects to address local needs, ie investments solely within the utility's area.

Moreover, the Rules require transmission providers to revise their tariffs to:

- demonstrate that the regional planning process has appropriate, non-discriminatory qualification criteria;
- identify the information that must be submitted by prospective transmission developers, and the date by which such information must be submitted; and
- include a description of a transparent and non-discriminatory evaluation process for the selection of proposed transmission facilities for purposes of cost allocation.

This policy was introduced because FERC considered that the ROFR resulted in planners not considering potentially more efficient or cost effective solutions to regional needs, ie higher cost solutions were included in regional plans.

PJM, NYISO and California have proposed a process (for reliability projects) where the RTO determines, as a part of a comprehensive planning process, a range of transmission needs. Following this, the RTO allows interested parties to propose specific transmission projects that could solve the problem. The RTO then evaluates the projects proposed, and identifies an initial solution. Alternative projects are then solicited and evaluated against the initial project proposed. If the proposal gets approved, the developer who proposed that project is then obligated to build it. We have chosen PJM Order 1000 filing as a case study of these arrangements, and so a more fulsome description of these arrangements is contained in Appendix A.

4 New Zealand

The main organisations involved in electricity transmission in New Zealand are:[15]

- Transpower – the grid owner, and system operator in New Zealand. Transpower is a state owned enterprise ie it is owned by the New Zealand government, but operates as a private business;
- the Electricity Authority – the rule maker who develops and administers the Electricity Industry Participation Code (the Code). It also undertakes a market administrator service provider role, as well as monitoring and enforcing compliance with the Code. The Electricity Authority is an independent Crown entity; and
- the Commerce Commission (the Commission) – the economic regulator.

Transpower is responsible for operating the transmission system. This occurs through a service provider contract with the Electricity Authority.

Transpower is also responsible for transmission system planning. It has a number of requirements under the Code that it must comply with. Transpower publishes an Annual Planning Report (APR), which provides information about:

- the current capabilities of the existing network;
- demand and generation forecasts for the following 10 to 15 years; and
- the network's ability to meet these needs.

The APR meets Transpower's requirement to produce a Grid Reliability Report (GRR) and Grid Economic Investment Report (GEIR) as required under the Code.

Transpower is also responsible for investment decision making via the process described below.

In relation to capital expenditure (capex) on transmission (ie investment) in New Zealand is classified as either "base" or "major" capex. Base capex is approved by the Commission prior to each regulatory period. Here, the Commission evaluates the level of base capex proposed by Transpower. The Commission then determines and sets an allowance to allow recovery of this amount. This is similar to the regulatory process in Australia, where an allowance for capex is approved but particular projects are not.

In contrast, major capex is assessed and approved on a project by project basis. Major capex is defined as that that is necessary to meet grid reliability standards, or provide a net electricity market benefit. Major capex is required to be consulted on, assessed and approved on a project by project basis using the requirements set out in the Capex

---

15 For further information please see: Transpower (www.transpower.co.nz); Electricity Authority (www.ea.govt.nz); and Commerce Commission (www.comcom.govt.nz).

Input Methodology (the Methodology). The Methodology has been produced by the Commission and can be considered similar to the guidelines or framework and approach papers that the AER produces. The Capex Input Methodology sets out:

- the requirements that Transpower must meet, including the scope and specification of information required, the extent of independent verification and audit required, and the extent of consultation required;
- the criteria that the Commission will use to evaluate capital proposals; and
- the time frames and processes for evaluating the proposals.

The process for major capex being decided upon and approved is summarised below:

- Transpower notifies the Commission of its intent to plan a major capex project. Both then agree on a consultation programme and timeframes, including that there will be sufficient consideration of non-network solutions;
- Transpower will then apply the Grid Investment Test (GIT) to identify the proposed investment, and submit its major capex proposal. The GIT is similar to the Regulatory Investment Test for Transmission (RIT-T) in Australia. It involves three key steps:
  - identification of market development scenarios and associated probabilities of these occurring;
  - estimation of the investment's net market benefits associated with each scenario; and
  - calculation of the market benefit as a probability weighted average of the scenario specific net market benefits;
- Following this, the Commission then approves the investment proposal, and so Transpower recovers the expenditure.

We note that these major capex proposals can be submitted at any time during the regulatory period.

5 Great Britain

There are a number of key organisations involved in transmission planning in Great Britain.[16] There are three for-profit companies that are the transmission owners of onshore networks, specifically:

- National Grid Electricity Transmission (NGET) – owns and operates the transmission system in England and Wales. It is also the National Electricity Transmission System Operator of Great Britain, ie the system operator of both the onshore and offshore transmission network;
- Scottish Hydro Electric Transmission Limited – owns and operates the transmission system in the north of Scotland; and
- Scottish Power Transmission Limited – owns and operates the transmission system in the south of Scotland.

The economic regulator (Ofgem) is also a key organisation. Lastly, there are also a number of offshore transmission owners. Offshore transmission owners are selected on a competitive basis through a tender process run by Ofgem. Generators have a choice of constructing transmission assets themselves, or to opt for an offshore transmission owner (OFTO) to do so. If they construct the assets themselves, then the generator must transfer the assets to an OFTO post construction.

In relation to onshore transmission, planning is undertaken by the three transmission owners (TOs) in coordination. Each TO must "cooperate and assist" each other in transmission planning. NGET uses technical modelling to prepare and develop planning assumptions, which are to be used in planning. TOs can submit or propose changes to these planning assumptions. These are used in planning by the TOs.

Further, each onshore TO must develop and maintain a separate Transmission Investment Plan, which covers a period of seven years. TOs are responsible for making sure their systems meet the relevant technical engineering standards. The system operator monitors the TOs plans. Each TO must provide NGET with the most up to date version of its plan. It must also provide those parts that may have a material effect on *other* TOs to those parties concerned. TOs also have to coordinate in terms of detailed construction planning where required, eg where investment is required in a connection between two TO systems.

NGET develops and maintains a separate plan – the NGET Investment Plan – that sets out the proposed changes to its transmission system that are likely to have a material effect on any TOs Plan or offshore TOs transmission system. This Plan must be developed in consultation with the TOs. This generally reflects the individual TOs plans.

---

16 For further information please see: National Grid (www.nationalgrid.com/uk/Electricity/) and Ofgem (www.ofgem.gov.uk).

Investment decision making is the responsibility of each TO. Each TO gives effect to its plan, while NGET gives effect to its NGET investment plans. Key investment decisions are made during the price control process, which is undertaken by Ofgem. Similar to the AER, Ofgem may employ technical engineering consultants to review business plans.

Ofgem then approves a capital expenditure allowance, with this not linked to specific investment projects ie the same process that is undertaken in Australia. Ofgem also approves revenue drivers for each business. This allows the revenue allowance to automatically adjust in response to changes in demand and/or firm access levels. Consequently, there is no need for the regime to include either contingent projects or project by project reviews, since business have revenue automatically adjusted. Lastly, Ofgem does not undertake any scrutiny of individual investments, ie there is no investment test or project reviews.

In relation to offshore transmission developments, competition was introduced (as discussed above). However, there were concerns that this competition was resulting in inefficient investments, eg multiple point to point networks. Therefore, the UK Government and Ofgem have attempted to take steps to better coordinate offshore developments.

Accordingly, NGET produces an Offshore Development Information Statement, which is designed to facilitate the coordinated development of the onshore and offshore transmission system. Further, each OFTO who plans to make changes to its transmission system must develop and maintain an investment plan.

6 Germany

The main organisations involved in transmission planning in Germany are:[17]

- the transmission owners: Amprion, EnBW Transportnetze AG, TenneT TSO GmbH and 50Hertz Transmission – these TOs all cover different geographic areas, and are all for-profit businesses; and

- the regulator – Federal Network Agency (Bundesnetzagentur).

The TOs develop transmission development plans for their regions. TOs are subject to revenue regulation from the regulator.

Further, TOs may develop investment budgets for major projects, eg where investments are needed to guarantee quality of supply, to facilitate transfer of energy from renewable sources, and to integrate new power plants into the system. The regulator must approve these investment budgets. These are for *extra* revenue above the business' revenue cap to cover the capital costs of these investments.

6.1 Electricity Network Development Plan

In 2011, the Federal Government passed the "Energy Package", which focussed on grid expansion and the development of renewable energy.

This included a requirement for the four TOs to jointly produce a 10 year Electricity Network Development Plan, which is to be updated on an annual basis. This provides information relating to the need for "optimising and reinforcing the grid as well as its expansion". The core objective of the plan is to set out expansion needs in the network to provide a safe and reliable network in response to changing conditions of supply – with these based on the energy policy shift towards renewable energy supplies.

This Plan will be examined and assessed by the Federal Network Agency. The Federal Network Agency will use the development plan as a basis for the development of the Federal Requirement Plan Act, which is then to be passed by the German parliament (the Bundestag).

Further, this also changed the planning process from a territorial based system to a federal based system, which is designed to streamline procedures. Previously, projects that affected more than one territory would require each individual territory to conduct a separate approval process.

The first Electricity Network Development Plan has recently been published, along with its initial assessment by the Federal Network Agency. The Federal Network

17 For further information please see: Bundesnetzagentur (http://www.bundesnetzagentur.de/cln_1911/DE/Home/home_node.html) and Bundesministerium fur Wirtschaft und Technologie (http://www.bmwi.de/English/Navigation/root.html)

Agency presented this plan to the Federal Ministry of Economics and Technology. The Ministry will now submit a Federal Requirements Plan Act for adopting by the Federal Cabinet by the end of December 2012.

6.2 Off-shore wind farms

Unlike the UK, in Germany offshore transmission rights have been allocated to incumbent TOs.

Under legislative changes introduced in 2011 the Federal Agency for Maritime Shipping and Hydrography (BSH) is required to establish an offshore grid plan every year in cooperation with the Federal Network Agency and the Federal Ministry of the Environment. This offshore grid plan has recently been released for consultation.

The draft offshore plan for the North Sea identifies offshore wind projects suitable for cluster connection. It also provides sites for converter platforms, cross-border power lines and possible linkages between them. A separate offshore grid plan for the exclusive economic zone of the Baltic Sea is also being prepared.

More recent legislative changes (in August 2012) also adopted a number of rules that aim to speed up the expansion and connection of offshore wind farms through the introduction of a binding offshore grid development plan.

This imposes an imposition on TOs to prepare and present an annual offshore grid development plan starting from 3 March 2013, which will set out the necessary measures for the enhancement and expansion of offshore grid connections.

It also included introduction of a rule for allowing compensation of the construction and operation of power lines connecting to offshore wind farms, where there are grid connection delayed and disruptions of power lines.

7 Republic of Ireland

The main organisations involved in transmission planning in the Republic of Ireland (Ireland) are:[18]

- the transmission owner – ESB Networks, who owns the transmission and distribution networks in the Republic of Ireland; and
- the transmission system operator (TSO) – EirGrid, which is owned by the Irish government. It was established as a result of the government's decision to create an independent organisation to carry out the TSO function, and so facilitate competition in the electricity market.[19]

EirGrid is responsible for transmission planning. It is also responsible for transmission investment decisions, up until the point of detailed network design. EirGrid produces a number of transmission development plans.

ESB Networks is responsible for the detailed network planning, procurement and construction.

Economic regulation is undertaken by the Commission for Energy Regulation (CER), which sets out the transmission revenue that can be collected from customers. This is distributed between EirGrid and ESB Networks in accordance with infrastructure agreements.

We note that in 2007, the Single Electricity Market (SEM) was created covering both Northern Island and the Republic of Ireland. The key characteristics included: a gross pool; a single wholesale price for the island of Ireland; a system of transmission constraint payments; and a capacity payment mechanism.

Consequently, following this establishment, elements of transmission policy has also been harmonised, eg harmonised transmission charging policy. Therefore, planning in Ireland is also done with consultation between the different TSOs.[20]

Specifically, EirGrid must:

- consult with SONI to prepare a development plan for the transmission network, in order to guarantee security of supply for the following five years; and

---

18 For further information: please see ESB Networks (http://www.esb.ie/esbnetworks/en/home/index.jsp); EirGrid (www.eirgrid.com); and Commission for Energy Regulation (www.cer.ie).

19 Under s14(2)A of the Electricity Regulation Act 1999, only EirGrid may be granted a licence as TSO in the Republic.

20 The TSO in Northern Ireland is the System Operator Northern Ireland (SONI). The transmission owner in Northern Ireland is the Northern Ireland Electricity Limited (NIE), which is a subsidiary of the ESB Group.

- consult with the distribution system operator, ESB Networks and SONI to establish transmission system security and planning standards subject to the approval of the CER.

8 European Directives

The European Commission has recently made changes to its electricity policy, specifically through:

- Regulation (EC) No 714/2009 ("regulation") on conditions for access to the network for cross-border exchanges in electricity; and
- Directive (EC) 2009/72/EC ("directive") concerning common rules for the internal market in electricity.

In particular, this Regulation and Directive contains a number of policies that are directly relevant to the TFR namely in relation to the production of long-term network development plans.

The Regulation and Directive are prescriptive in terms of what must be contained within the long term plans. However, there is flexibility in how this information is presented. Further, there is also flexibility in terms of what other planning documents TSOs choose to produce. In spite of these requirements, planning and investment decisions are still left to national regulators and TOs. The requirements under the Regulation and Directive are discussed in further detail below.

8.1 Electricity Regulation

Article 8 of the Regulation states that the European Network of Transmission System Operators for Electricity (ENTSO-E) should publish a biannual, non-binding Ten Year Network Development Plan ("Community TYNDP") for the European community.[21] This plan should include: modelling of the integrated network, scenario development, a European generation adequacy outlook and an assessment of the resilience of the system.

This plan is designed to increase information and transparency regarding investments in electricity transmission systems that are required on a European basis and to support decision making processes at both a regional and European level.

As set out in Article 8 of the Regulation the plan must:

- build on national investment plans eg the European generation adequacy outlook is based on national generation adequacy outlooks prepared by each individual TSO;
- take into account regional investment plans:
  - Article 12 of the Regulation states that TSOs must establish regional co-operations within ENTSO-E, and publish a regional investment plan

21 The first Community TYNDP was published in June 2010, with the most recent Community TYNDP published in July 2012.

biannually. They may even undertake investment decisions based on that regional investment plan;

— ENTSO-E has defined 6 regional groups, which are designed to address the challenges for grid development and integration of new generation at a regional level;

- for cross-border interconnections, build on the reasonable needs of different system users and integrate long term commitments from investors; and
- identify investment gaps, with a focus on cross-border capacities. We note that a review of barriers to increasing cross-border capacity of the network arising from different approval procedures or practices may be annexed to the plan.

The Regulation also establishes the Agency for the Cooperation of Energy Regulators (ACER). This has a number of responsibilities. However, of most relevance here are the following, ACER must:

- provide an opinion on the contribution of the Community TYNDP to the objectives as set out in the Regulation;
- provide an opinion on the consistency of the Community TYNDP and national ten year network development plans ("national TYNDP", discussed below):
  - — if ACER finds inconsistencies between these plans then it will recommend amending either plan as appropriate;
  - — if ACER considers that the national TYNDP plan should be amended, then it will recommend that the relevant national regulatory authority undertake this;
- monitor the implementation of the Community TYNDP.

8.2 Electricity Directive

Article 22 of the Directive sets out that TSOs are required to produce a national TYNDP annually.

These must be submitted to the relevant regulatory authority, and be based on existing and forecast supply and demand.

The national TYNDP plans must:

- be consulted on with all relevant stakeholders;
- indicate to market participants the main transmission infrastructure that needs to be built or upgraded over the next 10 years;
- include all the investments already decided;

- identify new investments that have to occur within the next three years; and
- provide a timeframe for all investment projects, ie those that are projected outside the next three years.

TSOs shall make "reasonable assumptions" about the evolution of the generation, supply, consumption and exchanges with other countries, taking into account investment plans for regional and Community wide network (ie those plans discussed above).

The relevant regulator has a number of functions that are similar to those outlined for ACER above. This includes that:

- the regulator will examine the plan to see whether it covers all investment needs identified through consultation, and whether it is consistent with the non-binding Community TYNDP;
- if there is any doubt on whether the plans are consistent, then the regulator will consult with ACER. It may then require the TSO to amend its plan; and
- the regulator shall monitor and evaluate the implementation of the national TYNDP.

We note that if the TSO (other than for reasons beyond its control) does not proceed with an investment that was to be executed in the first three years of the plan, member states shall ensure that the relevant regulatory authority must take one of the following three options (if the investment is still relevant):

- require the TSO to execute the investment;
- to organise a tender procedure open to any investors for the investment in question or;[22]
- oblige the TSO to accept a capital increase to finance the necessary investments and allow independent investors to participate in the capital.

22 If this occurs, then the regulatory authority may oblige the TSO to agree to: financing by a third party, construction by a third party, building the new assets concerned itself, or operating the new assets concerned itself. Financial arrangements will be subject to approval by the regulatory authority.

A PJM Filing on FERC Order 1000

As detailed above in section 3.6, in 2011, FERC issued Order 1000 'Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities'. This included a number of reforms relating to: planning, cost allocation and right of first refusal. Earlier in 2012, PJM received FERC approval of planning process enhancements that enabled PJM to comply with a number of new requirements under Order 1000.

On 25 October 2012, PJM Interconnection (PJM) filed its revised tariff to further comply with Order 1000.[23,24]

This included:

- compliance with expanded requirements under Order 890 planning principles as set out in Order 1000;[25]
  - PJM sets out that its existing transmission planning proposal complies with the planning principles as set out in Order 890 and expanded in Order 1000;
- proposing procedures that provide for consideration of Public Policy Requirements consistent with Order 1000:
  - PJM proposes a process where states can ask it to study specific projects they are interested in, and assuming they can agree on cost allocation, those projects can be incorporated into the transmission plan;
- proposing a process providing for competitive solicitation for new transmission proposals consistent with Order 1000. The proposed arrangements for competitive solicitation are discussed in more detail below.

---

23 See http://www.pjm.com/9CBED779-A977-4929-B798-97C90D9EDA49/FinalDownload/DownloadId-F6A1BE25F0C023320D06CE46AC05878D/9CBED779-A977-4929-B798-97C90D9EDA49/~/media/documents/ferc/2012-filings/20121025-er13-198-000.ashx.

24 We note that PJM has specified in their filing that revisions should only be considered if FERC finds that their current contracts with transmission owners are not protected by the Mobile-Sierra doctrine. Under the doctrine, FERC is required to demonstrate serious harm to the public interest as a prerequisite to mandating modifications to operating agreements between transmission owners and the RTO.

25 These requires transmission providers to: participate in a regional transmission process that produces a single, regional plan that satisfies Order No. 890 principles; in consultation with stakeholders, evaluate alternative transmission solutions that might meet the needs of the region more efficiently or cost-effectively than solutions identified by individual transmission providers in their local planning process; and in consultation with stakeholders, consider proposed non-transmission alternatives on a comparable basis.

Competitive Solicitation

PJM propose an alternative process to comply with the competitive solicitation provisions proposed in Order 1000. PJM states that Order 1000 recognises that there must be exceptions to the requirement for competitive solicitation to reflect both the realities of maintaining reliability, as well as respecting an incumbent transmission owner's rights.

In its filing PJM "urges [FERC] to provide deference to PJM's proposal to balance [FERC's] desire for competitive solicitations with the practical needs to meet real short term deadlines to address imminent reliability needs".[26]

In FERC Order 1000 (and the subsequent FERC Order 1000-A) FERC set out that:[27]

> "[O]ur focus here is on the set of transmission facilities that are evaluated at the regional level and selected in the regional transmission plan for purposes of cost allocation, and not on transmission facilities included in local transmission plans that are merely "rolled up" and listed in a regional transmission plan without going through a needs analysis at the regional level (and therefore, not eligible for regional cost allocation). Similarly, our reforms are not intended to affect the right of an incumbent transmission provider to build, own and recover costs for upgrades to its own transmission facilities, nor to alter an incumbent transmission provider's use and control of an existing right of way"
>
> "In Order No. 1000, the Commission required public utility transmission providers to remove from Commission-jurisdictional tariffs and agreement provisions that grant a federal right of first refusal to construct transmission facilities selected in a regional transmission plan for purposes of cost allocation. The Commission did not, however, require public utility transmission providers to remove a federal right of first refusal for local transmission facilities or upgrades to an incumbent transmission provider's own transmission facilities, and did not alter an incumbent transmission provider's use and control of an existing right of way"

PJM has interpreted the statements above, and so FERC Orders 1000 and 1000-A, as setting out that the following investments should not be subject to competitive solicitation. It states that the following should not be included in competitive solicitation:[28]

- an upgrade to an incumbent transmission owner's transmission facilities;

26 PJM is subject to deterministic reliability standards.

27 FERC Order 1000, paragraph 226; and FERC Order 1000-A, paragraph 357.

28 Compliance Filing of PJM Interconnection LLC, 25 October 2012, p.50.

- an enhancement or expansion located solely within an incumbent transmission owner's Zone[29] and the costs of the transmission facilities are allocated solely to the Zone in which the transmission facilities are located;

- an enhancement or expansion located solely within an incumbent transmission owner's Zone and the transmission facilities are not included in the relevant [regional] transmission plan for cost allocation purposes; and

- an enhancement or expansion proposed to be located on an incumbent transmission owner's existing right of way and the transmission facilities would alter the incumbent transmission owner's use and control of its existing right of way under state law.

PJM proposes that projects that meet these criteria will be allocated to the incumbent transmission owner in the Zone in which the facilities are located i.e. the same process as which currently occurs in PJM.

A "time based" approach to defining what projects should be subject to competitive solicitation is proposed by PJM. In other words, requiring competitive solicitation unless PJM, based on a defined set of criteria and in a transparent manner determines that there is not enough time to conduct a competitive solicitation before the facilities are needed. This approach only applies to investments to meet reliability needs. Market efficiency projects would all be put out to competitive solicitation.

PJM considers that this approach ensures that the Order 1000 requirements do not adversely impact PJM's ability to address reliability needs in a timely manner. PJM proposes to allow 'proposal windows' where an entity who has pre-qualified may submit a project proposal. This involves the following process:

- stakeholders must go through a pre-qualification process prior to the proposal window – to qualify the potential developer must demonstrate that it has the necessary financial resources and technical expertise to construct, own and operate transmission facilities;

- PJM must notify entities if they have qualified or not;

- parties can then propose projects during a proposal window, with proposals providing specified information;

- PJM then reviews and selects project proposals based on a number of criteria including:

  - whether the proposal addresses and solves the posted violation, system condition or economic constraint;

  - the proposal meets a benefit cost analysis ratio of at least 1.25:1;

29 A "Zone" is a defined area within the PJM Control Area, as set out in the PJM Open Access Tariff and the Reliability Assurance Agreement. Each "Zone" equates to a region of PJM where a sole transmission operator operates.

- whether the proposal would have secondary benefits (e.g. also meet reliability standards in a neighbouring region); and
- any other factors such as cost effectiveness, the ability to complete the project in a timely manner, and the potential risk and delay associated;

- if the project is selected, and a non-incumbent developer satisfies a number of criteria, then it will be assigned to potentially construct the assets; and
- the project will then be included in the Regional Transmission Expansion Plan (RTEP), and submitted to the PJM Board for review and approval.

PJM has developed three categories of projects, where competitive solicitation may occur:

- long-lead projects (where these are needed in 5+ years), which have a 24 month planning cycle. Here, PJM would have time to hold a 120 day proposal window (with the potential for a second window if no offers were received):
  - These projects tend to be the more significant projects likely to be of interest to non-incumbent developers;
- short-term projects (where these are needed in 3-4 years), which have a 12 month planning cycle. Here, PJM would have time to hold a 30 day proposal window;
- immediate need reliability projects (where these are needed in less than 3 years). If there is sufficient time then PJM will open a proposal window taking into account the project's overall timeframe:
  - PJM expects that that in most cases solutions to these projects would be offered by incumbent TOs/merchant transmission developers. PJM notes that in these scenarios due to both system reliability and time constraints it would be impractical and imprudent to hold another proposal window process; and
  - These projects are typically lower voltage, lower cost and so of less interest to non-incumbent developers.

For short-term and immediate projects if no proposals are received, then PJM will simply identify the solution and designated this to the incumbent TO (i.e. the same planning process as currently occurs).

To support this approach PJM undertakes a historical analysis of projects to assess how many projects would be subject to competitive solicitation, and fall into each of these categories. This analysis is summarised below.

Since 1999 PJM has undertaken 2,700 baseline upgrades to the network:

- of these 120 projects (4.4%) were "new green field projects" i.e. not upgrades to existing facilities (since these are not subject to competitive solicitation under FERC Order 1000); and

- 70 of 120 projects were facilities located in one Zone and allocated solely to that Zone (not subject to competitive solicitation under FERC Order 1000).

Therefore, applying the Order 1000 criteria and so ruling out upgrades to existing facilities/those allocated solely to a single zone, only **50 projects** (1.9%) would have been eligible to be designated to a non-incumbent transmission developer through a proposal process. Of these 50 projects:

- 40 (80%) would have been classified as long-lead projects;

- 7 (14%) would have been short-term; and

- 3 (6%) as immediate need reliability projects.

PJM uses this analysis to demonstrate that its "time based" process would consider all projects that would be considered under the "solution based" process as set out in Order 1000. However, more interestingly this analysis suggests that a relatively small amount of projects are likely to be subject to competitive solicitation going forward.

FERC is currently considering this filing.