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Competition in Electricity Transmission

An international study on customer interests and lessons learned

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1. Executive Summary

1. *Introduction*

In November Navigant was commissioned to prepare a paper for National Grid to contribute to its response to OFGEM on the Integrated Transmission Planning and Regulation (ITPR) initiative. Given OFGEM's role and its premise that different approaches to transmission investment should be used where they can drive benefit for consumers, this paper addresses two simple but related questions:

"Is electricity transmission competition in the interests of customers? What lessons can we take from other markets?"

Given the context of this question and the importance of OFGEM's actions on ITPR being consistent with its remit, we have chosen to use the five key dimensions of its customer responsibility for our evaluation, namely:

- The security of supply of electricity and gas to consumers;
- The reduction of greenhouse gases;
- Promote efficiency and economy on the part of licensees;
- Protect the public from dangers arising from (inter alia) the transmission of electricity;
- Secure a diverse and reliable long term energy supply

Following a section in the paper that provides a perspective on transmission competition in the GB market, evidence and examples are presented from a mix of countries that have introduced elements of competitive tendering for high voltage electricity transmission, namely USA, Canada, Argentina and Australia.

2. *Common Themes from Lessons Learned*

While there have been specific conclusions in each country and region researched, there are also a number of common themes that we can draw out that cut across international boundaries:

1. **Timeframes** - Many countries are taking steps towards greater competition in electricity transmission, however there is very little history and experience to draw on with regard to completed projects and lessons that encompass success and failure of delivery, ongoing maintenance and ultimate impact on system reliability.
2. **Whole of Life Cost/Benefit –** It is relatively easy to establish a competitive tender focused on reducing up-front costs. However international experience (particularly from the US/Canada) points to the importance of considering whole of life and net-present-cost elements to provide best protection for customers and longer term system integrity. These costs are not easy for regulators to assess however and do require a thorough cost benefit analysis, including consumer benefits that are often difficult to assess with accuracy. There is also some evidence

that a tender introduces inherent bias towards a significant capital-based transmission project rather than other opex-related innovations or changes to relieve system constraints.

3. **Bidding Progression –** There is growing evidence in the US market of a progression in approach from bidders, starting with fairly simple competition based on up-front capital costs through to greater use of capped prices and caps including longer term operating and maintenance expenditure. Ultimately this provides a lesser risk that customers will face economic surprises, however may pose challenges for bidders to do this without facing undue risks themselves in the long run.
4. **Level Playing Field –** Questions commonly arise (cf Australia) as to how best to balance the need for favourable economics and to leverage existing assets and capability vs the desire for a level playing field for all bidders. It may be reasonable for an incumbent to make effective use of their investment in easements for new transmission; what is not so reasonable is where an incumbent cross-subsidises investment between contestable and uncontestable investment to appear more competitive.
5. **Provider of Last Resort –** Experience in all markets studied highlights the criticality of having a back-up plan and provider of last resort should the chosen transmission provider fail to deliver. Incumbent transmission operators will expect compensation to keep their back-up scheme alive in case the alternative plans fail to proceed as planned. There is also a risk that a significant reduction on the incumbent TO's role will make their ability to perform this "last resort" role more difficult as their capital base and network coverage erodes.
6. **Complexity of Interactions –** The increase of complexity in planning for and establishing transmission under a competitive arrangement should not be under-estimated. This has an obvious transaction cost for the regulator and SO; what is not so easy to estimate but is far higher is the broader inefficiency in planning and delivery timeframes, coordination of multiple players and the impact of less clarity of responsibility between SO and TO, including the potential impact on reliability.
7. **Reliability Standards –** Experience from all regions studied demonstrated the importance of a consistent national framework for setting transmission reliability standards. This is a critical question for Great Britain under ITPR as the electricity system overall continues to come under pressure from renewable growth and a reduction in centralized flexible generation. It is also an area where OFTO arrangements did not need to be far reaching given the lesser consequences of lower reliability for an offshore wind generator compared to onshore transmission.
8. **Difficulty of Democracy –** As much as allowing key customers to decide which projects should proceed sounds a worthy goal, as witnessed in Argentina this democratic approach is fraught with difficulty given the various vested interests of all market participants. A truly independent judgement that is transparent and auditable while recognizing the importance of customer outcomes is a preferable approach.

3. Other Conclusions

Other conclusions reached through our research are set out in Section 7.

4. Conclusions by Customer Interest area

Customer Interest Area	Conclusions
Promoting efficiency and economy on the part of the licensee	• Some evidence exists that planning and build timeframes will push out under competitive tendering, especially with the complexity of "go early" schemes. • This may well be offset by cost efficiencies and benefits from an increase in innovative approaches to transmission build and operation. • The impact on incentive arrangements for the System Operator will require close attention by OFGEM.
The security of supply of electricity (and gas) to consumers	• Risks of system security impact from Argentina however little elsewhere as yet • System reliability will require clear national standards and is likely to become more complex to understand and maintain
The reduction of greenhouse gases	• Competition can promote the reduction of greenhouse gases in the initial design if the assessment framework rewards such initiative. • International experience suggests that during the life of the asset there is little or no incentive to innovate to meet climate change goals
Protecting the public from dangers	• Reputation of bidders and owners in the long term is an issue of importance • A focus on consistent reporting and management of faults and customer interruptions is vital to ensure safety and assurance of network performance
Secure diverse and reliable long term energy supply	• Little evidence that diversity of supply is negatively impacted; positive outcomes may well occur from greater competition in transmission improving feasibility of further supply options • Effective management of system reliability may become more challenging with a large number of CATOs

5. Specific Out-takes for National Grid

While there are a number of overall conclusions, specific areas we would highlight that are of particular relevance for National Grid's position are:

a) The reality that it is still relatively "early days" in the development of competition in transmission requires caution on hard and fast conclusions related to success. While there is evidence of up-front capital cost savings many of the competitive tenders are yet to proceed through delivery phase to enable true longer term success to be properly assessed.

b) The definition of "success" in establishing initial arrangements and performance standards is important. This should include the wider set of customer interests that go well beyond simple cost economics and a more holistic approach to network performance that addresses reliability, whole-of-life benefits and wider system interests that require asset owners and managers to maintain a sound reputation and contribute constructively to the overall integrity of the grid.

c) OFGEM have a duty to current and future customers with a range of customer interest areas as noted above. Even if there are short term cost savings the longer term benefits for future customers are not clear. The wider ramifications of ITPR in terms of customer impact also go beyond transmission competition given the considerable System Operator impacts and potential in theory to extend this approach to lower voltage networks as well if it is deemed a success.

d) National Grid's role as the Provider of Last Resort needs to be clearly set out along with fair expectations for compensation and how this is managed in the overall system planning. National Grid's ability to perform this ongoing role should also be highlighted as it should not be taken for granted.

e) Even though it is an incumbent, National Grid can act now to adopt an innovative approach to new transmission to enable it to win new competitive tenders and present a fresh approach to the regulator and the market. This may be through new partnerships or an independent review of its technical and commercial approach to transmission costs and tenders.

f) Costs and complexity vary depending on the approach selected, however if more rigorous initial arrangements are sought then significant up-front costs are likely both in the detailed design of ITPR arrangements and the role for the System Operator and Regulator in early tender rounds. As a regulated and listed entity National Grid should at least expect reasonable compensation for this establishment and higher ongoing cost, let alone any additional equity risk premium that may impact its WACC.

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2. Introduction

2.1 Background

Since 2012 OFGEM has been leading a project on Integrated Transmission Planning Regulation (ITPR) which has focused on introduction of competition to electricity transmission in Great Britain (GB) and new responsibilities for the GB System Operator. After extensive consultation a set of conclusions were published in March 2015. These decisions included:

- An enhanced role for the GB System Operator so that it leads the identification of system needs and assesses options to meet those needs.
- The need for a package of measures to mitigate the potential for conflict of interest for National Grid given the System Operator's enhanced role and its ownership of the Transmission Operator in England and Wales.
- The planned introduction of changes to ensure that different approaches for regulating the delivery of transmission investment are used where they can drive most benefit for consumers. Of most relevance to this paper is OFGEM's comment: "*We see substantial advantages in extending the use of competitive tendering beyond its current use offshore. We will develop and set up arrangements to tender new, separable and high value onshore assets*."

On October 19 OFGEM released a new consultation titled "Extending competition in electricity transmission: arrangements to introduce onshore tenders". Responses to this are required by 11 January 2016.

Given OFGEM's role and its premise that different approaches to transmission investment should be used where they can drive benefit for consumers, this paper addresses two simple but related questions:

"Is electricity transmission competition in the interests of customers? What lessons can we take from other markets?"

Navigant has written this paper for National Grid to inform their consultation response and dialogue with OFGEM and DECC. We include a section in the paper that provides a perspective on transmission competition in the GB market before looking at international examples where lessons can be learned to inform the local debate in a balanced way.

2.2 International experience of electricity transmission competition

A handful of countries have introduced elements of competitive tendering for high voltage electricity transmission. Our intention is to produce evidence and lessons learned from a number of these markets with slightly different characteristics, but still of relevance to Great Britain.

- The US has an extensive record of competitive tendering for transmission under the FERC 1000 regulations. Our analysis includes a detailed review of competitive solicitations conducted by:

    - California ISO
    - PJM
    - Southwest Power Pool (SPP)
    - Midcontinent ISO (MISO)
    - New York ISO
- We also provide analysis from Alberta, Canada with a focus on the Fort McMurray West project that was tendered by the Alberta Electricity System Operator (AESO)
- Further evidence of a more qualitative nature is presented for Australia and Argentina to highlight the process and lessons learned. For each there are positive elements to consider for GB and challenges to take note of.

It should be noted that despite the international competitive tendering activity in markets such as the USA, our conclusions by and large are not based on projects that have been constructed. This does limit our ability to provide firm evidence of issues such as lack of maintenance, construction cost over-runs, technical infeasibility or other customer impacts that may occur over time.

2.3 Definition of Customer Interests

In theory there are many different ways that "customer interests" can be defined. Given the context of this question and the importance of OFGEM's actions on ITPR being consistent with its remit, we have chosen to use this construct for our analysis. The sake of clarity, we interpret "customer" as being synonymous with "consumer" – the end users of electricity - for the purposes of this paper.

OFGEM's remit is focused on acting in a manner to protect the interests of existing and future consumers in Great Britain. This has several dimensions however, including:

1. The security of supply of electricity and gas to consumers
2. The reduction of greenhouse gases;

In undertaking its functions OFGEM must also:

3. Promote efficiency and economy on the part of licensees;
4. Protect the public from dangers arising from (inter alia) the transmission of electricity;
5. Secure a diverse and reliable long term energy supply

Where appropriate OFGEM must undertake its functions by promoting competition. However, on a case by case basis it must examine whether other means would better protect the interests of consumers. Even if lower up-front costs can be expected from competitive bidding there are questions which need to be asked and answered against the wider elements constituting consumer interests. These include (but are not limited to) the following:

- **Promoting efficiency and economy on the part of the licensee**
  - How could planning and build timeframes be impacted by a competitive tendering approach?
  - What evidence is there that transmission competition is likely to lead to greater levels of innovation?
  - Could the incentive arrangements on National Grid as SO be diluted if the transmission assets are owned by third parties?
- **The security of supply of electricity (and gas) to consumers**
  - What may be the impact on overall system security?
  - What are the risks of multi-party ownership to the current effective emergency recovery arrangements?
  - May system reliability overall (SQSS) be affected by a plethora of different transmission owners?
- **The reduction of greenhouse gases**
  - What would be the effect on the progressive upgrading of network equipment (for example to reduce losses) under OFGEM's proposed 20 year price control arrangement?
  - Could the effectiveness of NG's SO incentives to reduce greenhouse gas emission be reduced by third party ownership of the assets?
- **Protecting the public from dangers**
  - How will multi-party ownership of the transmission system affect safety?
  - How will third party TOs detect faults? Or will they rely on the SO? What would this mean for clarity of responsibility for safety?
- **Secure diverse and reliable long term energy supply**
  - Does the introduction of multi-party ownership contribute to diversity of energy supply; and does it impact on long term reliability?

2.4 Paper Structure

This paper commences with some relevant high-level insights from Great Britain, particularly the competitive tenders for offshore transmission links (OFTO) that were managed by OFGEM E-Serve. After creating this context evidence is presented from the US and Canada, followed by information on the experience of transmission competition in Australia and then Argentina. Conclusions are drawn against the customer benefit questions by bringing together evidence across all the international markets highlighted.

3. Insights from transmission competition in Great Britain to date

3.1 Context – the GB electricity transmission market

There have been a number of regulatory innovations in the GB operation and ownership of transmission assets since 2005 which have moved away from the historic model of an integrated transmission asset owner and operator.

The BETTA reforms implemented in 2005 introduced separate asset ownership and system operation. In this case the two Scottish incumbents (SHETL and SPT) remained owners of their respective transmission networks and NG became the separate SO of those systems.

Since 2009 OFGEM has managed a competitive tendering process which allows third parties to bid to build and own parts of the offshore transmission network in the waters around GB. NG remains the SO for the entire network.

The current ITPR reform proposals can be viewed as an evolution of the earlier initiatives and so it is important to understand where the current proposals build on these earlier experiences. It is also critical to identify where the ITPR proposals differ from earlier developments and what the implications of those differences may be. In this section we identify where the ITPR proposals are inherently different from earlier reforms and analyze the implications of those differences.

3.2 Insights from GB with regard to customer interests

3.2.1 Introduction

OFGEM has concluded from its experience of the offshore transmission regime that competition in the provision of electricity transmission assets can bring benefits to customers as a result of reductions in initial investment costs. However, OFGEM's statutory duties towards electricity customers are broader than achieving lower up from investment costs (and, importantly, extend to the protection of both current <u>and future</u> consumers).

We have examined the ITPR proposals, as they are currently explained, in the context of each of the main areas of OFGEM's statutory responsibilities relating to consumers to see where they deliver benefits, where there may be areas of concern, and also to identify where further development of the proposals may be required.

3.2.2 Promoting Efficiency and economy on the part of the licensee

Benefits - One appealing factor of third party investment is that it allows competition to apply downward pressure on investment costs in new transmission capacity along with a number of other benefits such as:

- *Innovation*: It encourages innovation and new ideas, improving delivery and long-term efficiency at the initial point of investment.
- *Reduces asymmetry of information*: Competition can reveal information on the scope for efficiencies, through bidding processes and increased opportunities for regulatory benchmarking.
- *Access to financing*: Competitors may have access to alternative financing sources and additional equity which supports the provision of services.

There are increased costs associated with the proposals - Competition within transmission does also bring some additional costs over traditional incumbent delivery, which must be taken into account when deciding if contestability is a viable option:

- *Losses of network benefits*. Some network benefits may be lost as a result of contestability, for instance, where costs are duplicated or system design to remove constraints is negatively affected.
- *Higher transaction costs*. Bidding costs can be substantial in many large scale procurements

There is a moral hazard issue which can give rise to inefficiencies - The reduction of the asset base of the incumbents and fragmentation of transmission owners raises a moral-hazard-in-teams problem (when individuals cannot observe the effort level of others, only the total output of the team). The transmission owner's measure of performance is conditioned by the system operator's behaviour and therefore their incentive scheme. Thus, any incentive given to third party owners cannot be accurately addressed without specifying those of the system operator. By its nature moral hazard in teams reduces accountability. For example, an outage can be claimed to result from poor line maintenance by the TO or from imprudent dispatching by the SO. On the other hand, high power prices may be due to a proper dispatching motivated by low line quality or to an undue conservatism of the system operator.

Greater complexity of interaction can also result in inefficiencies - This configuration will increase the number of interaction/configuration transactions such as system planning, data transfers, asset availability etc. across ownership and jurisdictional lines. These additional interactions result in an increase in complexity of transactions resulting in additional bureaucracy, leading to system inefficiency and ultimately an increase in cost.

There will be greater costs of regulation. More regulated actors will add an additional burden and cost on the regulator to create and manage new price controls for each new regulated actor as well as enforcement, monitoring and reporting.

There is a risk that regulatory arrangements may not result in efficient outcomes across the whole system - A key requirement for delivering efficient transmission investment plans cost effectively is to enhance the utilisation of primary network assets and make full use of operational measures and various corrective control techniques. These operational measures directly compete with asset-based solutions, but at present there are no clear commercial incentives for their full implementation where transmission asset ownership is separated from system operation. The majority of NGET and Scottish Transmission Operators' revenue is RAV-based. Historically there has been a tendency to favour capital investment.

To counter this problem OFGEM has made improvements to the regulatory approach under RIIO-T1. However, new investments by third party transmission owners are expected to be a RAV-based approach which may continue to disproportionately favour capital expenditure rather than find the most efficient solution between capex and opex. Consequently there will be a major dependency on the ability of the regulator ex-ante to evaluate and benchmark investment and operational costs prior to the price control period.

As the proposed ITPR proposal is predicated on delivering efficiency through competition, there needs to be an adaptation of a price control mechanism (subsequent modification of the current regime) and creation of incentives for network asset and alternative non-network asset based solutions to be compared on an equal footing. Given the growing role of various information and communication technologies in supporting efficient network operation and investment, it is increasingly important that these options are fully considered to substitute for asset-based reinforcement.

There can be tender process inefficiencies - The OFTO regime has demonstrated a number of potential inefficiencies related to the tender process such as the risk of cost reopeners post competition and the tender process leading to delays of asset delivery that may need to be borne ultimately by consumers.

Evaluation of whole-of-life costs in competitive bidding poses a major regulatory challenge - Limiting the exposure of third party transmission owners (and hence the customer) to risk would require the development of a comprehensive bidding process that is inclusive of not only the investment cost but also accounts for the maintenance, operational and emergency restoration costs associated with the asset over its lifespan (and not just the price control period or the amortisation period, both of which can be different). If the proposed regime is skewed towards up-front investment cost to the detriment of maintenance and operation costs, the result could be the selection of lower cost bids that would trigger higher operational costs. Thus, careful thought should be given to the split between treatment of lifetime opex and capex in any contracting arrangement which places a major responsibility (and challenge) on OFGEM to identify such behaviour.

3.2.3 The reduction of greenhouse gases

Price controls on transmission asset owners which are fixed for long periods may inhibit innovation aimed at tackling climate change - It is suggested that the proposed price controls for third party transmission asset owners will offer a 20-year revenue stream. However, over such a long period it can be expected that technical (as well as operational) innovation will take place which, if implemented, has the potential to reduce greenhouse gas emissions 9as well as enhance efficiency). Such innovation could enhance the performance of the network (for example by reducing losses) or it could facilitate innovations in the operation of the market (for example by enabling greater demand side participation or the scope for flexible response). Without some form of incentive or other in-period re-openers in the price control there will be no incentive for the introduction of new innovative technologies or solutions as well as incentive to encourage lower carbon solutions.

3.2.4 Protecting the public from danger

A reliable transmission operator of last resort is essential - The proposals identify the need for a transmission operator of last resort in the event that any transmission owner is unable to perform their duties. The proposals do not however indicate who will bear the responsibility and what the conditions are for this arrangement. It may be expected that the responsibility will ultimately fall on the existing TOs (National Grid, SHETL and SPTL) as they would be best placed to manage such a responsibility due to the size of their asset base. In the long term the asset base of the incumbents could be reduced as a result of the successful operation of the ITPR proposals. Thus the risk of acting as TO of last resort could become harder for them to manage. In this case identifying a transmission owner of last resort who could be entrusted to manage large assets safely could prove problematic. Further, as the asset base of NG reduces, so its ability to bear the risk of regulatory incentives would also reduce. This could, if the ITPR policy is very successful in introducing new transmission owners of high value assets, and reduce the ability of the regulator to apply incentive arrangements to encourage SO efficiency.

Reputation of new transmission asset owners - One of the features of the OFTO scheme is the ease of exchange of ownership. One example of this is the Blue Transmission consortium, which was led by Macquarie and pre-qualified for the first tranche of OFTOs. Mitsubishi Corporation was then introduced as an equity partner to the consortium, buying out the Macquarie stake soon after. Allowing such an approach of bid, build and then sell - equivalent to “pass the parcel” behaviour - may not instill confidence that longer term customer interests will be considered or that the asset owners have a real reputation to maintain for such long-lived assets. This could affect the public perception of the safe management of the transmission system as a whole.

3.2.5 Security of Supply of Electricity

Tenderers for transmission assets ownership should be able to demonstrate their capability to adhere to all aspects of SQSS standards - The incumbents under the current regulatory regime own and maintain an entire network. This critical mass facilitates the ability of the incumbent to take on the necessary responsibility under SQSS. In network planning, the SQSS defines the range of system conditions, including the demand and generation background to be assessed and the events for which the transmission system is required to be secure. These conditions must be applied when designing transmission network infrastructure and connections to it. Similarly, the operational criteria in the SQSS define the range of system conditions to be assessed and the events for which the transmission system is required to be secure. 3rd party transmission owners must be able to demonstrate that they are able to meet the challenges of adhering to these standards over the life time of the asset. This may be a particular concern in those cases where tenderers have a limited transmission asset base even where they are able to demonstrate contracts with third party service providers since such providers themselves may have limited resources to meet emergency situations and also in relation to participation in emergency scenario planning.

Lower security levels are acceptable for OFTO assets compared to onshore assets - The limited asset base of OFTOs should not be seen as analogous to onshore third party transmission. Since offshore transmission is not required to connect demand, lower redundancy (or security factor) is acceptable for offshore assets than onshore assets under the SQSS. This should be recognised in tendering for third party investment in the onshore transmission network. It is important to recognise that OFTOs tendered to date have been of a materially different scale and risk profile to the full electricity transmission network in GB. Offshore network assets are developer-led, and as such to a large extent the developers are incentivised to plan, design, and deliver their assets efficiently in respect of the generation it serves. This works best with single dedicated links to individual wind farms as the perceived difficulty of coordinating and delivering more complex solutions across separate wind farms can discourage more holistic solutions.

4. Evidence from the United States and Canada

4.1 FERC Order 1000 in the United States

The North American transmission grid is aging and requires improvements and upgrades over the next few decades to meet the reliability standards and support increased reliance on renewable energy, expected coal unit retirements and anticipated load growth. Because updating and expanding the grid could result in higher electricity costs to rate payers, the Federal Energy Regulatory Commission (FERC) introduced competitive edge into transmission planning by introducing FERC order 1000 in July 2011 and reaffirmed it in May and October of 2012. According to this order, the long-standing federal Right of Federal Refusal (ROFR) was removed for transmission projects identified in a regional plan which required cost allocation of the project throughout a region. This means that incumbent utilities no longer are automatically granted the right to build, own, and operate large-scale transmission projects located within their service territory. There were four limitations identified around ROFR elimination:

- ROFR removal did not apply to a transmission facility that is not selected in a regional transmission plan for purposes of cost allocation.
- Order 1000 allowed, but does not require, public utility transmission providers in a transmission planning region to use competitive bidding to solicit transmission projects or project developers.
- Nothing in the Order 1000 affected state or local laws or regulations regarding the construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities.
- Order 1000 recognized that incumbent transmission providers may rely on regional transmission facilities to satisfy their reliability needs or service obligations. The rule requires each public utility transmission provider to amend its tariff to require reevaluation of the regional transmission plan to determine if delays in the development of a transmission facility require evaluation of alternative solutions, including those proposed by the incumbent, to ensure incumbent transmission providers can meet reliability needs or service obligations.

To support competition, Order 1000 also required -

- coordinated, open and transparent regional transmission planning processes to address undue discrimination
- transmission planning at the regional level to consider and evaluate possible transmission alternatives
- the production of a regional transmission plan
- the cost of transmission solutions to be allocated fairly to those who benefit

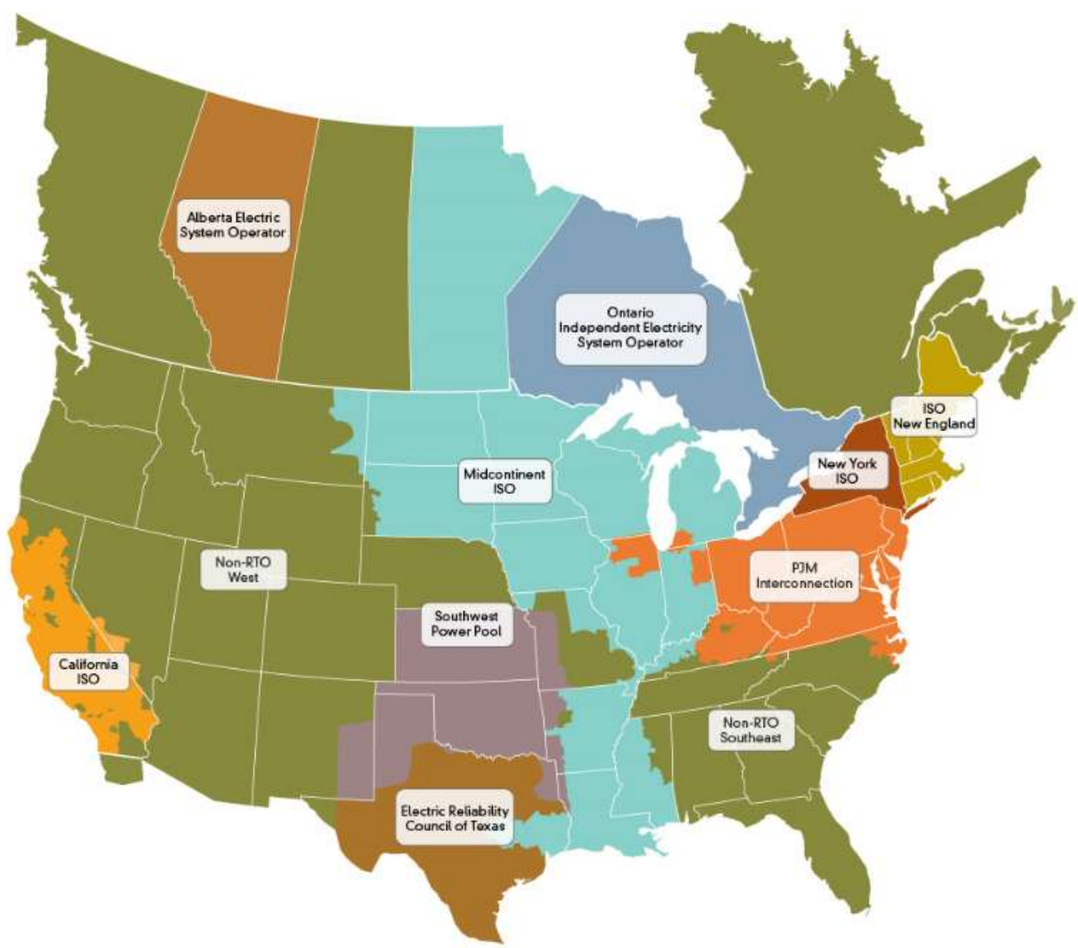
Order 1000 also introduced requirements related to Public Policy transmission planning. Each public utility transmission provider must establish procedures to identify transmission needs driven by public policy requirements and evaluate potential solutions to those needs.

4.1.1 Regional Implementation

Independent System Operators grew out of Orders Nos. 888/889 where the Commission suggested the concept of an Independent System Operator as one way for existing tight power pools to satisfy the requirement of providing non-discriminatory access to transmission. Subsequently, in Order No. 2000, the Commission encouraged the voluntary formation of Regional Transmission Organizations to administer the transmission grid on a regional basis throughout North America (including Canada) As shown in the figure 4.1 below there are seven ISOs under FERC jurisdiction in United States of America. These are New England ISO (ISONE), New York ISO (NYISO), PJM, Midcontinent System Operator (MISO), Southwest Power Pool (SPP), Electric Reliability Council of Texas (ERCOT) and California ISO (CAISO). Canada has two ISOs that are Alberta Electric System Operator (AESO) and Independent Electric System Operator (IESO).

ISOs as regional entities are responsible to conduct transmission planning processes every year based on the rules and regulation set forth by their tariffs.

Figure 4.1 – Independent System Operator Map of North America



4.1.1.1 Early/Late

To implement Order 1000 regional entities approached the ROFR independently and introduced their own models in their respective compliance filings. Interpretation of the compliance filings by different regional entities shows two basic methodologies of implementation. Also each regional entity has defined their own criteria for reliability, public and economic projects that can be competitive and that cannot be part of the bidding process and open to competition.

- In the "Early methodology" the Regional Transmission Organization (RTO) identifies the necessary transmission upgrades needed as part of their expansion planning processes and solicits for innovative solutions and proposals. The preferred solution is selected by the RTO and the winning developer has the rights to own, finance and construct the proposal. This methodology is adapted by NYISO, ISONE, SPP and PJM.
- In the "Late methodology" the RTO identifies the necessary transmission upgrades during their expansion planning processes and provides the solutions. The developers in this methodology can compete only to finance, own and construct the solution based on the costs. This methodology is adapted by AESO, CAISO, ERCOT, SPP and MISO.

4.1.1.2 Regional Objectives

To implement regional and interregional reforms of FERC 1000, most of the regions adopted a two phased approach based on the compliance deadlines. The first phase developed changes to transmission planning process were implemented at regional level and the filings were submitted to FERC and solicitations were conducted as early as 2013. The second phase of interregional filings are happening now after co-ordination among different ISOs. Following sections describes each ISO's approach for implementing proposed regional reforms into the transmission planning process.

A. New York Independent System Operator

NYISO conducts solicitation only for reliability and public policy projects. Economic transmission projects are selected based on a pre-existing transmission planning process. Figure 4.2 below shows public policy, reliability and economic planning processes. Following is the selection criteria adopted by NYISO for transmission projects

- Qualified incumbent TOs & non-incumbent developers are eligible to propose solutions
- Reliability Planning Process culminates in NYISO selecting the more efficient or cost-effective transmission solution
- NYISO also selects the public policy transmission solution, subject to impact on wholesale electricity markets
  - Selection is for purposes of cost allocation & recovery under NYISO's Tariff
  - NY PSC has authority over siting
- No change to Economic Planning Process: current voting process culminates in selection [NYISO]

Reliability Planning Process – Once the reliability needs are identified through planning process solutions are solicited for all types of needs in the sectors of transmission, generation, and demand-Side.

Also all categories of transmission projects (including Market-based, Regulated Backstop, and Alternative Regulated) are requested for solicitation.

- Phase I: In this phase all qualified solutions are evaluated for viability that is if the proposed solution is technically practicable and if it can be delivered in time and sufficiency that is the proposed solution meet the identified need.

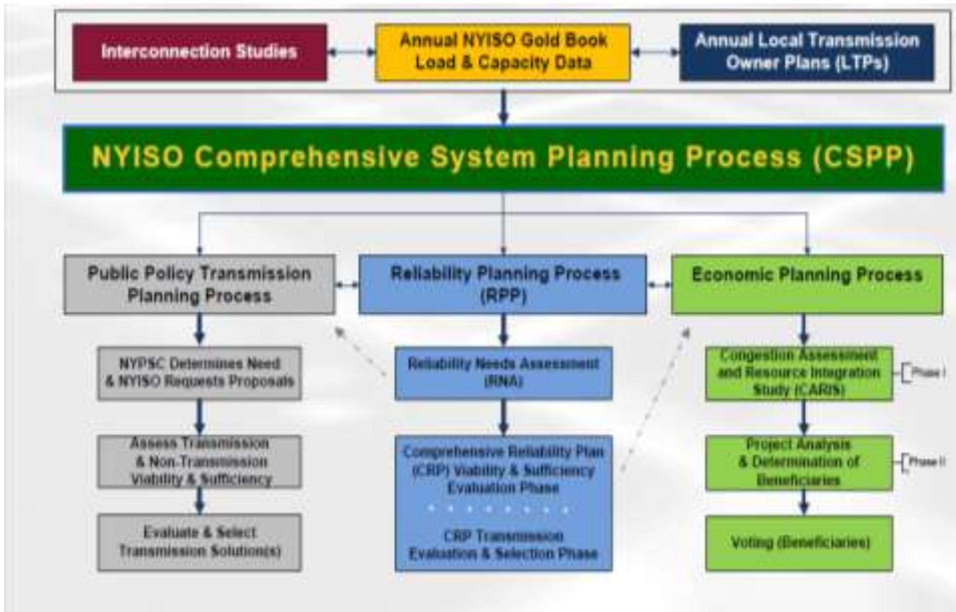
- Phase II: In this phase regulated transmission solutions are evaluated for system impacts, efficiency, economics and local transmission plan sensitivity. System impacts assessment involves identifying any reliability issues caused by proposed solution. Efficiency of the solution is evaluated for expandability, operability and performance of new transmission projects. Economic assessment includes total capital cost and cost-per-MW evaluation. In addition to the above evaluations local transmission plan sensitivity is assessed for information only that is evaluated if the proposed regional solution is more efficient or cost effective than local TO plans.

Public Policy Transmission Planning Process – This is performed in parallel with Reliability Planning Process. In this process solutions are evaluated to transmission needs driven by public policy requirements.

- Phase I – NYPSC identifies transmission needs driven by public policy for which NYISO solicits solutions (transmission, generation, or EE/DR). NYISO evaluates solutions for viability and sufficiency to meet the need similar to the reliability planning process.

- Phase II: NYISO evaluates proposed transmission solutions to identify the more efficient or cost effective transmission solution. Market Monitor assesses the potential market impacts of the transmission solution. NYISO Board may select a transmission solution for purposes of cost allocation.

Figure 4.2 – NYISO Comprehensive Planning Process

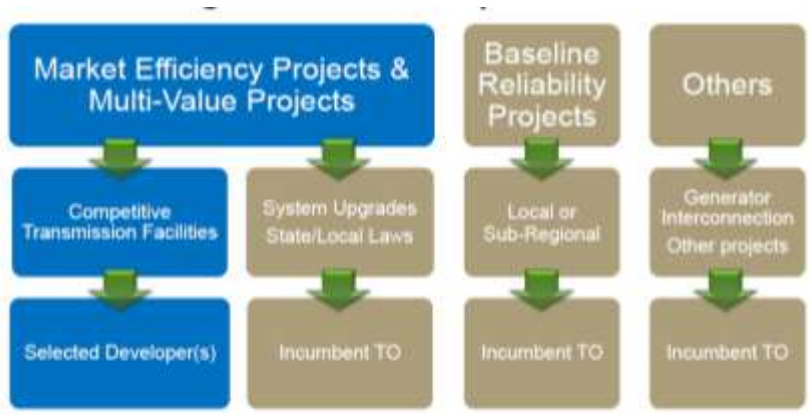


Backstop - If non-incumbent project is selected, NYISO may direct the incumbent TOs to proceed with a backstop solution in parallel to maintain reliability. NYISO already has an agreement with TOs to develop regulated backstop solutions for reliability needs which are developed in parallel to competitive solutions. Backstop solution is halted when NYISO is confident non-incumbent project will succeed, in such instances the backdrop is halted as early as possible.

B. Midwest Independent System Operator

MISO solicitation process includes the portion of New Transmission Facilities associated with Board approved Market Efficiency Projects and Multi Value Projects located in jurisdictions that do not have laws prohibiting non-incumbent transmission developers from owning, operating, and maintaining electric transmission facilities. It is important to note that New Transmission Facilities do not include upgrades, modifications, and expansions to existing transmission facilities. The applicability of the competition is only for new regionally cost-allocated projects. Any reliability driven projects or public policy driven projects were not included into the solicitation process.

Figure 4.3 – MISO transmission projects eligible for solicitation (Blue)



MISO selection process involves two phases. MISO Transmission Expansion Planning (MTEP) starts every year with needs assessment and submission of the proposed mitigations by the participants. Once mitigations are identified economic assessment is performed on the proposed mitigations to identify projects that would meet the Multi Value Purpose (MVP) or Market Efficiency Projects (MEP). Upon board approval of the MEP/MVP projects, MISO reviews approved projects for competitive transmission facilities and issues Request for proposal (RFP) for those projects. MISO evaluates developer Proposals for certainty, specificity, risk-mitigation, & cost with the oversight of MISO's Executive Oversight Committee (EOC) and makes the decision. Selected Developer(s) proceeds with project development & construction activities while MISO monitors project progress & updates Board of Directors with Project Reports.

Variance Analysis - MISO introduced a process called Variance Analysis after post approval of the projects to developers or TOs to ensure the transmission facilities are constructed in time to address project need. MISOs Executive Oversight Committee oversees this process and makes the decision. This post solicitation process is triggered if there are any cost increases, schedule delays, inability to complete or defaulted in selected developer agreement. MISO would initiate an inquiry and issue a public notice in such instances. Further analysis will be done by MISO to determine whether the project should be reassigned or cancelled or if a mitigation plan has to be implemented. If the project needs to reassigned it MISO assumes this will be to the given to the incumbent TO.

C. PJM

PJM's Order 1000 compliance filing expands PJM's regional planning process to provide opportunity for non-incumbent transmission developers to submit solution proposals. Transmission projects which are needed in 4 years or beyond are competitive, if projects are needed in 3 years or less they are likely to be designated to incumbents. If a project involves complete rebuild or new facilities with existing right-of-way these can be competitive.

PJM's filing establishes proposal windows allowing for competitive solicitation while balancing the need for projects to be selected, sited and constructed in time to solve identified reliability violations. The length of each proposal window will depend on the transmission upgrade's classification, which itself is determined by its required in-service date. There are three classes of transmission upgrade projects which define proposal windows during each planning cycle.

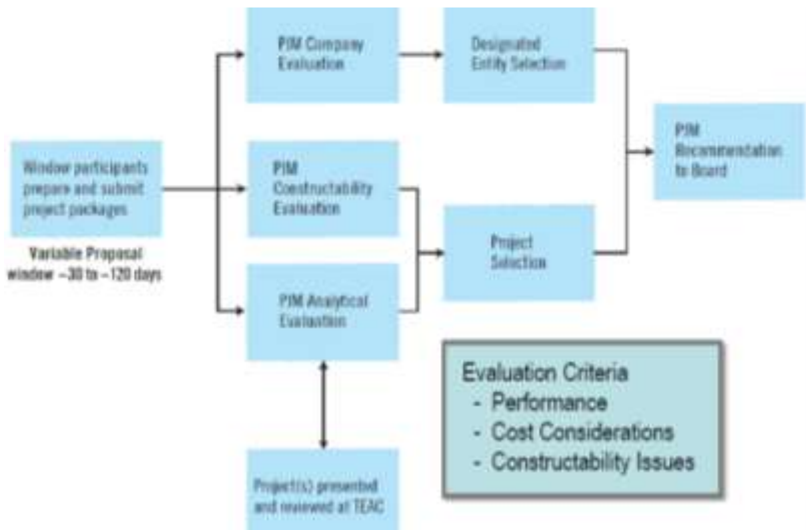
Immediate-Need Reliability Projects: If PJM determines that insufficient time remains for a short-term project proposal to be implemented, PJM may post reliability violations that could be addressed by a project required to be in service within three years.

Short-Term Projects: PJM will open a 30-day proposal window for projects to address reliability driven upgrades with required in-service dates between three and five years out.

Long-Lead Projects: PJM will open a 120-day proposal window for projects with required in-service dates greater than five years out that address identified reliability criteria violations, economic constraints, system conditions and public policy requirements.

The figure below shows the Regional Transmission Expansion Plan (RTEP) window process for the projects and evaluation criteria.

Figure 4.4 PJM RTEP process diagram



Re-evaluation: If the designated Entity fails to provide a development schedule or letter of credit or if it fails to meet a milestone in its development schedule that delays the project's in-service date, then PJM will re-evaluate the need for the project. Based on that reevaluation, PJM may:

- Retain the project in the RTEP
- Remove the project from the RTEP
- Include an alternative solution

If PJM retains the project, PJM shall determine whether to retain the Designated Entity or to designate the project to the incumbent transmission owner in the Zone where the project is located. In the event an incumbent transmission owner is the Designated Entity, PJM shall seek recourse through the Consolidated Transmission Owners Agreement or the Commission, as appropriate

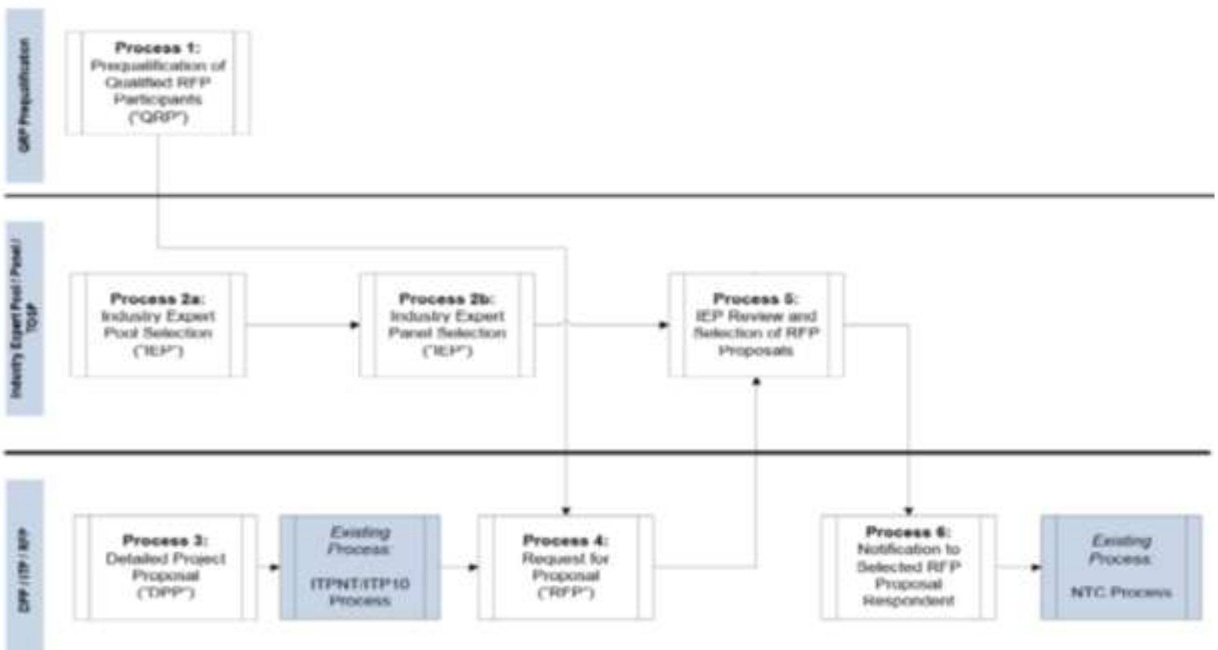
D. South West Power Pool

Any entity can submit Detailed Project Proposals (DDP) for Integrated Transmission Planning Near Term (ITPNT) and Integrated Transmission Planning 10 Year (ITP10) planning cycles. ITPNT analyzes the regions immediate transmission needs. ITP10 is for planning for 10-year horizon wherein solutions are assessed for 100 KV and above. SPP defined the criteria for the transmission facilities which can be part of solicitation as:

- Transmission facilities that are: ITP Upgrades, high priority upgrades, or Interregional Projects
- Transmission facilities with a nominal operating voltage of greater than 100 kV
- Transmission facilities that are not a Rebuild of an existing facility
- Transmission facilities that do not alter a Transmission Owner's use and control of its existing right of way under relevant laws or regulations

- Transmission facilities located where the selection of a Transmission Owner pursuant to Section III of this Attachment Y does not violate relevant law where the transmission facility is to be built
- Transmission projects that do not require both a Rebuild of existing facilities and new transmission facilities
- Transmission facilities that are not a Local Transmission Facility
- Also, transmission facilities that are not short-term reliability projects

Figure 4.5 SPP planning process diagram



As shown in the diagram above, DPPs are submitted by approved entities during ITPNT or ITP10 processes. All entities desiring to participate in the SPP solicitation process must apply to become Qualified RFP Participants (QRP).

SPP will issue the RFP for each Competitive Upgrade after study reports have been published and the list of recommended upgrades has been approved by the SPP Board of Directors. Each competitive upgrade will have 180 days from the issue date for the QRP to complete their RFP response. Each completed RFP response will be analyzed and scored by the Industry Expert Panel (IEP). IEP reviews RFP responses, rank and score solutions, each submitted RFP response is scored according to established criteria. IEP panel provides a recommendation to the SPP Board of Directors who chooses selected **RFP response and an alternate.** Notification To Construct (NTC) issued to Board-chosen RFP.

Alternate Approach - If, after accepting the NTC, the Designated Transmission Owner (DTO) cannot or is unwilling to complete the Competitive Upgrade as directed by the Transmission Provider, the Transmission Provider shall evaluate the status of the Competitive Upgrade and may designate a new

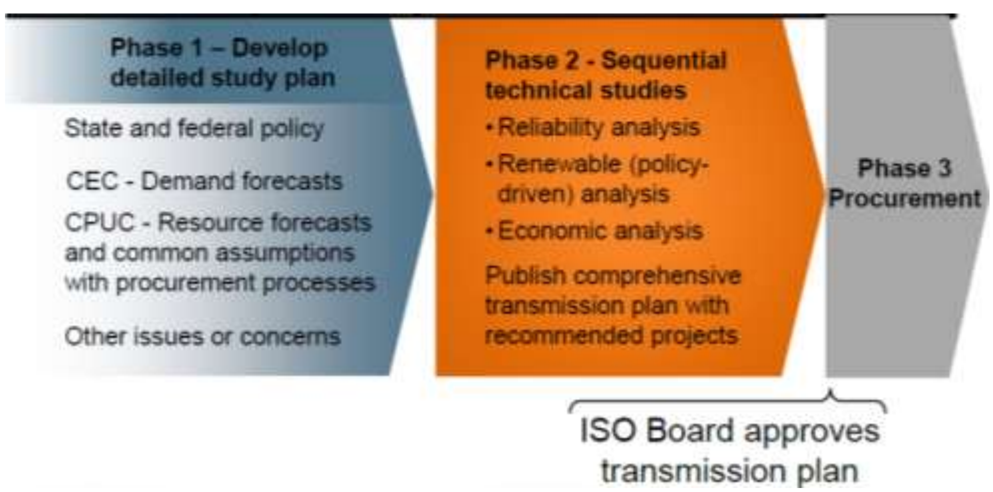
DTO for the Competitive Upgrade. This alternate DTO is designated by IEP as an outcome of the project selection process and informs the ISO ahead of time.

E. California Independent System Operator

CAISO annual transmission planning process relies on state policy and state agency input. There are three phases in the planning process as shown in the figure below. In Phase I detailed study plan is developed taking into consideration State and Federal policies, demand forecasts, resource forecasts and common assumptions with procurement processes. Phase II conducts the technical studies in sequential order that is reliability analysis, policy driven analysis and economic analysis.

Once the transmission plan for the year is finalized, CAISO presents it to the Board of Governors for approval and posts the board-approved comprehensive transmission plan on the site. If applicable, the CAISO will initiate the Phase III to solicit proposals to finance, construct, own, operate, and maintain regional transmission facilities identified in the transmission plan eligible for competitive solicitation. Regional transmission facilities eligible for competitive solicitation are those which are deemed needed under the comprehensive transmission planning process. Regional transmission facilities not eligible for competitive solicitation are facilities that involve an upgrade or improvement to, addition on, or a replacement of a part of an existing participating TO facility. Also transmission projects under 200 KV are not eligible for the solicitation.

Figure 4.6 – CAISO planning process diagram



Alternate Sponsor - If the CAISO determines that the Approved Project Sponsor cannot secure necessary approvals or property rights or is otherwise unable to construct a transmission solution CAISO shall take such action as it reasonably considers appropriate, in coordination with the Participating TO and other affected Market Participants, to facilitate the development and evaluation of alternative solutions. For reliability driven transmission solutions, the CAISO may, at its discretion, direct the Participating TO in whose PTO Service Territory or footprint either terminus of the transmission solution is located, to build the transmission solution, or the CAISO may open a new solicitation for Project Sponsors to finance, own, and construct the transmission solution. For all other transmission solutions, the CAISO shall open a new solicitation for Project Sponsors to finance, own, and construct the transmission solution.

F. Independent System Operator New England

ISONE solicitation process is still underworks and they are involved in the stakeholder process to review and file with FERC. ISONE has two different solicitation processes defined based on the type of projects. Economic and Reliability projects are solicited in certain steps while Public policy projects need to go through a different set of steps especially due to involvement of states and New England States Committee on Electricity (NESCOE).

Reliability and Economic projects - ISONE will issue a public notice with respect to each Needs Assessment for which a competitive solution process will be utilized.

Phase I - The notice will indicate that Qualified Project Sponsors may submit Phase One Proposals offering solutions that comprehensively address the identified needs. A PTO or PTOs shall submit an individual or joint Phase One Proposal for any need that would be solved by a project located within or connected to its/their existing electric system. If more than one Phase One Proposal has been submitted in response to the ISO shall perform a preliminary feasibility review of each proposal to determine whether the proposed solution:

- Provides sufficient data and that the data is of sufficient quality to satisfy Attachment K of tariff
- Appears to satisfy the needs described in the Needs Assessment
- Is technically practicable
- Is not eligible, to be constructed only by an existing PTO of the TOA because the proposed solution is an upgrade to existing PTO facilities (or utilizes PTO rights-of-way).

Phase II - The ISO will identify the most cost-effective and reliable solution as the preliminary preferred Phase Two Solution in response to each Needs Assessment. The ISO will report the preliminary preferred Stage Two Solution, together with explanatory materials, to the Planning Advisory Committee and seek stakeholder input on the preliminary preferred solution. The ISO will also notify the Qualified Project Sponsor that proposed the preferred Phase Two Solution that its project has been selected for development. The ISO will include the solution as a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, as appropriate, in the Regional system Plan (RSP) and/or its Project List, as it is updated from time to time in accordance with Attachment K.

For public policy projects ISONE should coordinate with NESCOE and Planning advisory committee during each phase of the process. For each project identified in the Public Policy Transmission Study that would be located within or connected to a PTO's existing electric system, that PTO [shall], and other Qualified Project Sponsors may, prepare (by the deadline specified by the ISO) a Stage One Proposal. The ISO will provide NESCOE and the Planning Advisory Committee with, and post on the ISO's website, a list of Stage One Proposals that meet the criteria including any ISO comments on the proposals in relation to the elements of the NESCOE matrix.

The ISO will report the preliminary preferred Stage Two Solution(s), along with its views as to whether the preferred solution(s) also satisfies identified reliability needs of the system, to NESCOE and the Planning Advisory Committee and seek stakeholder input on the preliminary preferred solutions. Upon receipt of a NESCOE Public Policy Transmittal in response to preliminary preferred Stage Two Solutions and the stakeholder input received thereon, the ISO shall notify the corresponding Qualified Project Sponsors, and include in the Regional System Plan and Regional System Plan Project List, as Public Policy Transmission Upgrade(s), the project(s) indicated therein as having been approved by the respective state regulatory authorities.

Back Stop - In the event the Qualified Project Sponsor fails to provide a construction schedule, or fails to meet any milestone in the construction schedule, the ISO may (i) remove the project from the RSP and/or RSP Project List, and reevaluate the need for such project or an alternative project, (ii) or retain the project. If the project is retained or an alternative project is developed, the PTO(s) in whose existing electric system the retained or alternative project would be located and/or to whose existing electric system would be connected shall be designated to construct, own and operate it.

4.1.1.3 Participant Due Diligence Requirements

A. New York ISO

Each entity should submit the following information to NYISO for the qualification and participation in the competitive solicitation process.

- Enhanced entity qualification and project information requirements
- Experience/plan for project financing, development, construction & maintenance (provide examples)
- Financial statements, credit rating, demonstration of financing capability
- Demonstration of site control or plan for obtaining control
- Schedule and status of contracts, permits, financing (submit agreements when available)
- Status of equipment & procurement plan
- Evidence of reasonableness of project cost estimates

B. Midcontinent ISO

All Transmission Developer Applications should provide the following details in the Transmission Developer Application Template. The template is organized into the following sections:

- General Information – this section collects all the legal names and contact information of the transmission developer
- Description of Operations - All Qualified Transmission Developer Applicants must provide a description of current operations to be included in the Transmission Developer Application. The description of current operations should summarize electric transmission assets, substation assets owned or maintained or operated by the applicant. Also the applicant is required to provide information of current transmission support resources such number of existing personnel engaged in transmission project implementation, man-years of experience in project implementation and O&M. Transmission Developer Applicant attests they can and will provide Current Business Standards and Practices Documents upon request

- Business Implementation Plan - The business implementation plan should summarize the following information:
    - Project Implementation Capabilities Plan - A detailed description of current capabilities and/or a plan to acquire required capabilities to implement transmission line projects and transmission substation projects
        - Capital procurement for project funding;
        - Project management;
        - Transmission line routing studies and/or substation siting studies;
        - Regulatory permitting including filing preparation, legal support, and testimony;
        - Right-of-way and other real estate acquisition;
        - Engineering, design, and land surveying
        - Material bidding and procurement;
        - Construction; and
        - Final commissioning and testing
    - Operations and Maintenance Capabilities Plan
    - Safety Assurance and Risk Management Plan
- Legal Information - The Qualified Transmission Developer Applicant must submit evidence that the applicant legally exists. The Qualified Transmission Developer Applicant must also submit a summary of any civil litigation in which the Qualified Transmission Developer Applicant is named as a defendant that is pending or has been ruled on within the past five years. The Qualified Transmission Developer Applicant must also submit a summary of any and all legal or regulatory compliance violations which are pending or for which the Qualified Transmission Developer Applicant has received an official citation during the past five years.
- Financial Information
    - The Qualified Transmission Developer Applicant must submit a capital procurement plan outlining applicant will procure funding to develop Open Transmission Projects and evidence that the Qualified Transmission Developer Applicant is capable of procuring at least $5,000,000.00 in capital
    - Should provide bank statements of the applicant or parent
    - Should history of bankruptcy, dissolution, merger, or acquisition in the five calendar years immediately preceding submission of the application.
- Written Commitments
    - Commitment to execute ISO Agreement;
    - Commitment to comply with all Applicable Laws and Regulations, codes, and standards governing the engineering, design, construction, operations, and maintenance of electric transmission facilities;
    - Commitment to register with the North American Electric Reliability Corporation as the transmission owner (TO), transmission operator (TOP), and transmission planner (TP);
    - Commitment to execute the Balancing Authority Agreement
    - Commitment to comply with FERC Form 715 Part 4 TRPC, Transmission Planning Criteria and Guidelines

- Commitment to comply with current requirements and standards regarding the interconnection of transmission facilities published by each incumbent Transmission Owner

C. PJM

PJM pre-qualification process for each developer involves submission demonstrated experience or information in each of the following categories:

- Previous Experience/Plan to Gain Expertise
  - The entity/individual has over 20 years of experience in areas specific to the proposed project
  - The entity/individual has experience in the areas specific to the proposed project of over 5 years and a robust plan that includes the participation of affiliates/partners that have over 20 years of experience
  - The entity has a robust plan that includes the participation of affiliates/partners that have over 20 years of experience
  - The entity has a plan
  - The proposed plan was found lacking sufficient detail
  - The filing did not include any information for this area

- Previous Record
  - The entity/individual has extensive background in the area of over 20 years
  - The entity/individual has extensive background in the area of over 10 years
  - The entity/individual has experience in the area of over 5 years
  - In the last 5 years, the company has had a major incident in this area
  - No previous record supplied
  - In the last 5 years, the company has had a major incident in this area

- Standardized Practices
  - Has prior experience using standardized practices
  - Has a plan to develop standardized practices
  - The proposed plan was found lacking sufficient detail
  - The filing did not include any information for this area

- Financial Statements
  - The financial statements of the entity or its affiliate, partner, or parent company for the most recent fiscal quarter, as well as the most recent three fiscal years, or the period of existence of the entity

- Equipment Failures
  - Has prior experience remedying equipment failures which includes a spares policy
  - Has prior experience remedying equipment failures
  - Has a plan to remedy equipment failures which includes a spares policy

- Has a plan to remedy equipment failures
- The proposed plan was found lacking sufficient detail
- The filing did not include any information for this area

- Right of Way Experience
  - The entity/individual has experience procuring RoW across many different regions in the US.
  - The entity/individual has experience procuring RoW across one or a few different regions in the US.
  - The entity/individual has experience outside of the US or has a robust plan that includes an affiliate/partner(s) that have experience across many different regions in the US.
  - The entity has a plan.
  - The proposed plan was found lacking sufficient detail.
  - The filing did not include any information for this area.

D. California ISO

California ISO requests the following information from the applicants who would like to participate in the solicitation process:

- Project Sponsor, Name and Public Identification, and Qualifications
- Past Projects, Project Management and Cost Containment
- Financial - Financial Resources
- Environment and Public Processes
- Substation - Experience and Abilities
- Transmission Line - Experience and Abilities
- Construction - Construction Plan and Management Practices
- Operation and Maintenance - Experience and Abilities
- Miscellaneous
- Officer Certification

E. South West Power Pool

Each Applicant must demonstrate that they meet qualification criteria in order to be approved as a QRP. The qualification is based on following categories:

- Membership Criteria - An Applicant must be a Transmission Owner or be willing to sign the SPP Membership Agreement as a Transmission Owner if the applicant is selected as part of the Transmission Owner Selection Process.
- Financial Criteria – Applicant should demonstrate good financial rating, a surety bond of $25,000,000 and few other requirements.

- Managerial Criteria - Applications for QRP will An application must show that the Applicant has requisite expertise by describing its capability, experience, and process to address the following areas:
  - Transmission Project Development
  - Internal safety program
  - Transmission Operations
  - Transmission Maintenance
  - Ability to comply with Good Utility Practice, SPP Criteria, and industry standards
  - Ability to comply with or demonstration of how the applicant plans to be able to comply with NERC Reliability Standards.
  - Any other relevant project development experience that the applicant believes may demonstrate its expertise in the above areas.

Applications for QRP will be evaluated by SPP to assess if the Applicant meets the qualification criteria and make the final determination. Qualified QRP Status is good for 5 years and the entity must re-certify annually no later than June 30th. If QRP qualifications change, then applicant must notify SPP for determination of eligibility to retain Qualified QRP status.

F. ISO New England

The application to be submitted to the ISO by an entity, other than a PTO (which shall be deemed to be a Qualified Project Sponsor), desiring to be a Qualified Project Sponsor will include the following information:

- The current and expected capabilities of the applicant to finance, license, and construct a Reliability Transmission Upgrade or Public Policy Transmission Upgrade and operate and maintain it for the life of the project
- The financial resources of the applicant
- The technical and engineering qualifications and experience of the applicant
- If applicable, the previous record of the applicant regarding construction and maintenance of transmission facilities
- Demonstrated capability of the applicant to adhere to construction, maintenance and operating Good Utility Practices, including the capability to respond to outages
- The ability of the applicant to comply with all applicable reliability standards
- The legal status of the applicant
- The extent to which the applicant satisfies state legal or regulatory requirements for siting, constructing, owning and operating transmission projects
- The experience of the applicant and its team in acquiring rights of way, and the authority to acquire rights of way by eminent domain, if necessary, that would facilitate approval and construction
- Demonstrated ability of the applicant to meet development and completion schedules; and

- Demonstrated ability of the applicant to assume liability for major losses resulting from failure of facilities

4.1.1.4 Project Selection Requirements

As stated earlier each ISO approached the compliance filing considering stakeholder inputs and developed the methodology for the project selection process. Some of them took early approach others took later approach. SPP conducts both early and later approach in the selection of projects.

A. New York ISO

The NYISO will consider proposed transmission solutions using the following metrics:

- The capital cost estimates for the proposed regulated transmission solution
- The cost per MW ratio of the proposed regulated transmission solution
- The expandability of the proposed transmission solution, including the impact on future expansion
- The operability of the proposed regulated transmission solution
- The performance of the proposed regulated transmission solution, such as interface flows and percent loading of facilities.
- The extent to which the Developer of a proposed regulated transmission solution has the property rights, or ability to obtain the property rights, required to implement the solution.

In addition to these metrics, the NYISO will also consider the following for the Public Policy Projects:

- Any criteria specified by the Public Policy Requirement or criteria/analysis provided by the NYPSC/NYDPS
- In consultation with its stakeholders, any additional metrics based on the context of the Public Policy Requirement

Based on its evaluation of the proposed regulated transmission solutions using these metrics, the NYISO will select the more efficient or cost-effective transmission solution to an identified Reliability Need and report the selected solution. NYISO does not make cost the primary criterion, or use weighting or a mathematical formula for selection purposes.

B. Midcontinent ISO

In evaluating Proposals, MISO will consider the following general aspects and weighting to each Competitive Transmission Facility evaluated:

- Competitive Transmission Line Facilities - The following weights will be applied to Competitive Transmission Line Facilities criteria:
    - o Cost and reasonably descriptive facility design quality: 30%
    - o Project implementation capabilities: 35%
    - o Operations, maintenance, repair, and replacement capabilities: 30%

- Transmission Provider planning process participations: 5%

- Competitive Substation Facilities - The following weights will be applied to Competitive Substation Facilities criteria:
  - Cost and reasonably descriptive facility design quality: 30%
  - Project implementation capabilities: 30%
  - Operations, maintenance, repair, and replacement capabilities: 35%
  - Transmission Provider planning process participations: 5%

C. PJM

PJM will evaluate all project proposals submitted during a proposal window. Based on that review, PJM will select, for review by the TEAC, those projects determined to provide the more efficient or cost-effective solutions based on the following criteria:

- A proposal would address and solve the posted violation, system condition or economic constraint
- The relevant benefits of the proposal meets a Benefit/Cost Ratio Threshold of at least 1.25:1
- The proposal would have secondary benefits such as addressing additional or other system reliability, operational perform, economic efficiency issues or Public Policy Requirement
- Any other factors such as cost effectiveness, the ability to timely complete the project and the potential risk and delay associated with obtaining necessary and timely regulatory approvals.

D. Southwest Power Pool

The IEP will develop a final score for each RFP proposal and provide its recommended RFP proposal and an alternate RFP proposal to the SPP Board of Directors for each Competitive Upgrade. The IEP may award up to one thousand (1000) base points for each RFP proposal. An additional one hundred (100) points shall be available to provide an incentive for stakeholders to share their ideas and expertise to promote innovation and creativity in the transmission planning process. The evaluation categories and maximum base points for each category are listed below.

- Engineering Design (Reliability/Quality/General Design), 200 points
- Project Management (Construction Project Management), 200 points
- Operations (Operations/Maintenance/Safety), 250 points
- Rate Analysis (Cost to Customer), 225 points
- Finance (Financial Viability and Creditworthiness), 125 points
- Incentive Points, 100 - **Each** RFP respondent that submitted a DPP that was selected for Competitive Upgrade shall receive one hundred (100) incentive points in the Transmission Owner Selection Process for that Competitive Upgrade, which shall be added to the total base points awarded by the IEP.

E. California ISO

CAISO uses a holistic evaluation approach to select an approved project sponsor and proposal. CAISO did not use pre-set weights for evaluation criteria stating that it would limit the flexibility to evaluate the large variety of regional transmission facilities that may be built. A comparative analysis evaluation better reflects the importance of individual selection factors that can vary according to the type of regional transmission facility. The selection factors are:

- Current and expected capabilities of the project sponsor and its team to finance, license, and construct the regional transmission facility for the life of the project
- Existing rights-of-way and substations that would contribute to the facility in question
- Experience in acquiring rights-of-way
- Proposed schedule and demonstrated ability to meet that schedule
- Financial resources
- Technical and engineering qualifications and experience
- Previous record regarding construction and maintenance of transmission facilities
- Demonstrated capability to adhere to standardized construction, maintenance and operating practices
- Demonstrated ability to assume liability for major losses resulting from failure of facilities
- Demonstrated cost containment capability, specifically, binding cost control measures (such as accepting a cost cap)
- Any other strengths and advantages the project sponsor may have to build and own the specific regional transmission facility

F. ISO New England

ISONE is still in process of regional process development. As per the recent FERC filing ISO-NE seeks input from the Planning Advisory Committee to determine which proposals would move forward to Phase Two, based on the selection criteria of cost, electrical performance, future system expandability, or feasibility. ISO-NE will identify which Phase Two proposal best meets the selection criteria, seeking stakeholder input from the Planning Advisory Committee on the preliminary preferred solution. ISO-NE will also post on its website why a transmission solution is ultimately selected in the regional transmission plan for purposes of cost allocation, and include the transmission project as either a reliability upgrade or market efficiency upgrade, as appropriate, in its Regional System Plan.

4.1.1.5 Status of Competitive Activity

Out of the 7 ISOs in United States of America so far competitive solicitation process cycle end-to-end is conducted so far only in CAISO and PJM. AESO and IESO in Canada have implemented a solicitation cycle each in their jurisdictions.

A. New York ISO

NYISO is assessing public policy driven transmission needs in coordination with PSC staff.

- **AC transmission projects -** PSC called for AC transmission projects to increase upstate to downstate transfer capability by approximately 1000 MW. Four developers proposed 22 different solutions out of which two segments are recommended by the PSC staff for competitive solicitation process.
- **Western NY –** PSC called for projects that increase Western NY transmission capability obtain full output for Niagara, maintain certain levels of simultaneous imports from Ontario across the Niagara tie lines and to maintain the reliability of the transmission system with fossil fuel generation in Western NY out of service as well as in-service.

B. Midcontinent ISO

MISO has one Market Efficiency Project that is needed to be approved by the board on December 10th. Upon approval by the board and RFP will be posted for the elements of the projects which can be part of competitive solicitation on January 8th 2015.

C. PJM

PJM's RTEP process completed two cycles of proposal windows in years 2013 and 2014 conducted so far and in the process of conducting the 2015 cycle. The first proposal window was in 2013 where in two solicitations were conducted that is Artificial island and Market efficiency projects.

The details of the 2013 proposal windows are as shown below:

- Artificial Island
  - Window opened on 4/29/2013
  - Closed on 6/28/2013
  - 26 proposals addressing operational performance from 7 entities
  - Approx. $100M - $1.55B
  - 1 project approved - $275.45M
- Market Efficiency
  - Window opened on 8/12/2013
  - Closed on 9/26/2013
  - 17 proposals addressing congestion from 6 entities
  - $0.19M - $528M
  - 1 project approved - $8M

In the year 2014 four RTEP proposal windows were solicited including an addendum window to address reliability projects. The details of these windows are as shown below:

- RTEP Window 1 – Reliability
  - Window opened on 6/27/2014
  - Closed on 7/28/2014
  - 106 proposals addressing reliability from 15 entities
  - 46 TO upgrade proposals: $0.02M to $139.2M
  - 60 greenfield Proposals: $10.2M to $1.4B

- 22 projects approved - all upgrades - Total $82.03M

- RTEP Window 2 – Reliability
  - Window opened on 10/17/2014
  - Closed on 11/17/2014
  - 79 proposals addressing reliability from 14 entities
    - 45 TO upgrade proposals: $0.2M to $103.7M
    - 34 greenfield Proposals: $6.1M to $450M

- RTEP Window 2 Addendum – Reliability
  - Window opened on 2/24/2015
  - Closed on 3/12/2015
  - 10 proposals addressing reliability from 4 entities
  - $0.96M - $25.5M
  - 1 Proposal approved to address all issues in this window

- 2014/15 Long-Term Window – Reliability, Market Efficiency
  - Window opened on 10/30/2014
  - Closed on 2/27/2015
  - 119 proposals addressing congestion from 22 entities
  - $0.01M - $432.5M
  - 11 projects approved earlier in October

2015 RTEP window is underway and so far two windows have completed solicitation as shown below:

- RTEP Window 1 - Reliability
  - Window opened on 6/19/2015
  - Closed on 7/20/2015
  - 91 proposals addressing reliability from 9 entities
  - 27 TO upgrade proposals: $0.013M to $73M
  - 64 greenfield Proposals: $6M to $167.1M
  - 21 projects approved earlier in October

- RTEP Window 2 – Reliability
  - Window opened on 8/5/2015
  - Closed on 9/4/2015
  - 23 proposals addressing reliability from 4 entities
  - 5 TO upgrade proposals: $0.075M to $6.0M
  - 18 greenfield Proposals: $4M to $47.5M

Lessons Learned - As can be seen from the RTEP windows the volume of proposals is relatively high and facing several issues. Some of the issues PJM is facing with the competitive process are:

- The number proposals for each transmission driver has increased analytically and administrative workload, in some cases significantly

- It has become very challenging for the ISO to distinguish between similar proposals

- ISO has to perform deep analysis on project cost issues, cost caps and constructability issues including siting risk. To analyze these consultants have to be hired which is becoming a challenge.
- It has become difficult for the ISO to implement small localized projects as developers attempt to influence decision-making.
- Workload has increased significantly for each RTEP cycle due to transparency requirements, and cost allocation debates.

To manage the workload and delays in RTEP process PJM is planning on eliminating sponsorship model and solicit bids for only selected projects or to reduce range of projects applicable to sponsorship model.

D. California ISO

CAISO is the early starter who solicited the first project Gates to Gregg on April 1st 2013. So far there are three cycles which have completed for the planning years 2012 – 2013, 2013 – 2014, and 2014 – 2015. The solicitation cycle, that is Phase III for 2015-2016 planning year will take place next year. The ISO's competitive solicitation process has been very active since 2013 and so far following selections are completed as shown in the table below. The current project which is still in the process is Harry Allen – Eldorado 500 kV transmission line.

Table 4.7 – CAISO solicitations completed

Year	Project	Region
2012 - 2013	230 kV Gates-Gregg line (2013)	CAISO
2013 - 2014	Delaney Colorado river	CAISO
2013-2014	Suncrest 230 kV 300 MVAr SVC	CAISO
2013-2014	Miguel 500kV bus.	CAISO
2013-2014	Estrella substation	CAISO
2013-2014	Spring substation project	CAISO
2013-2014	Wheeler Ridge Junction substation	CAISO

CAISO is going through a stakeholder process to address the lessons learned through the first solicitation process.

E. South West Power Pool

SPP has issued RFP for Walkemeyer project on May 5th 2015. IEP evaluation began on November 30th and will end January 29th 2016. Board of directors will be posted on April 12th and NTC will be awarded on April 26th.

4.2 Competition Transmission Development in Canada

4.2.1 Alberta Implementation

The Alberta Electric System Operator (AESO) is a not-for-profit, independent entity which is responsible for the safe, reliable and economic planning and operation of the Alberta Electric System. In 2010, the Alberta provincial government required that AESO develop a process which enables competition for development of certain transmission projects. The Competitive Process (as it is known) was approved by the Alberta Utilities Commission in February 2013. The Competitive Process is used for certain new transmission projects of a specific size and scope. As of December 5, 2015, it has been used only once - the Fort McMurray West 500kV Transmission Project (project details provided below).

The AESO indicates that the Competitive Process is comprised of three stages:

- Stage One - A Request for Expressions of Interest (REOI) where parties have an opportunity to indicate their interest in participating in the Competitive Process. The purpose of this stage is to create awareness of the project and to assist the AESO in gauging the level of interest in the project.
- Stage Two - A Request for Qualifications (RFQ) where interested parties submit their qualifications to deliver the project. The purpose of this stage is to identify a short-list of up to five respondents to move forward as proponents into the Request for Proposals (RFP) stage of the Competitive Process.
- Stage Three - An RFP where short-listed proponents develop and submit a proposal to undertake the project. The purpose of this stage is to identify the qualified proponent who can deliver the project at the lowest cost.

AESO indicates that at the completion of the RFP stage, a qualified company able to undertake the project at the lowest life-cycle cost will be selected. To encourage qualified participants the AESO identifies and clearly articulates the risks assumed solely by the selected company and the risks shared by both parties. For Fort McMurray West, the risks that are solely the selected company's include:

- refinancing during the project agreement period;
- inflation/deflation during the project agreement period;
- financial impacts from early/late completion;
- availability of project once placed in service;
- end term of asset condition;
- default of contractor; and
- termination by contractor default

Risks that are shared between the AESO and the selected company include:

- route change arising from commission decisions;
- technical cost savings proposals; and
- termination by Force Majeure

4.2.1.1 Early/Late

The Competitive Process is a late process where the project is well defined by the AESO and parties compete to construct, operate and maintain it.

4.2.1.2 Provisional Objectives

The AESO indicates that Competitive Process was developed to achieve the following objectives:

- Minimize life-cycle costs through competitive pricing;
- Create opportunity for maximum innovation throughout the life cycle of the facilities;
- Allocate risk most efficiently and effectively mitigate those risks;
- Foster efficient investment, operation and maintenance of assets across the life cycle of the facilities;
- Ensure facilities are designed to meet standards for performance, and to ensure reliable operation of the Alberta interconnected electric system; and
- Facilitate timely completion of projects.

4.2.1.3 Participant Due Diligence Requirements

The RFQ stage of the Competitive Process evaluates each respondent team on the following aspects: financial strength, financial capacity, and relevant project experience. These considerations are formally evaluated in two ways. First, there is a pass/fail test. The pass/fail looks at two aspects:

1. Financial Strength and Capacity – Clear demonstration that each team member or its guarantor can provide sufficient funding to perform the project. AESOs indicates it will look at equity, working capital, performance bonds and letters of credit.
2. Extra High Voltage Experience – Clear demonstration that the team members have line and substation project experience, including designing, building, operation and maintaining these facilities.

Second, there is a scored portion of the test. In this portion, respondents are evaluated and scored on five dimensions as illustrated in the following picture provided by the AESO.

Table 4.8 Scored Portion of Due Diligence Review (*Source: AESO*)

Scored Test	Weightings	Basis of Evaluation
Financing	20%	*Past Experience* *Key Individuals* *Understanding and Approach*
Respondent Team Lead	15%	
Route Development, Environment, Consultation, Relationship Management*	25%	
Design and Construction	20%	
Operations & Maintenance	20%	

Bidders selected to participate in the RFP process must pass all pass/fail conditions and score in the top of the RFQ respondents. For example, in the Fort McMurray West solicitation, AESO selected the top five RFQ respondents to participate in the RFP process.

4.2.1.4 Status of Competitive Solicitations

As of December 5, 2015 only one project, Fort McMurray West, has been awarded through the Competitive Process. The project is scheduled to be completed and placed in service in 2019.

4.2.1.5 Activity to Date

A second project was scheduled to be released through the Competitive Process, Fort McMurray East. However, due to economic factors impacting oil prices, AESO indicated that the underlying need for the project has been reduced and the Competitive Process for Fort McMurray East has been put on hold for the foreseeable future. Other than Fort McMurray East, there are no other projects identified for release through the Competitive Process.

4.3 Recent Solicitations - PJM

4.3.1 Artificial Island

Since the PJM process is an early in process, a variety of proposals were presented. The winning project included the following components:

- A new 230 KV to be constructed under the Delaware River from the Salem substation to a new substation tapping an existing 230kV line.
- Addition of a 500/230 kV Transformer at Salem substation
- A new 300 MVAR SVC to be constructed at the New Freedom substation
- An upgraded high speed optical ground wire relay communications to improve clearing times in the area

4.3.1.1 Project Objectives & Solicitation Background

The PJM solicitation was to develop a project or set of projects to improve stability, enhance operational performance and eliminate possible planning criteria violations around the Salem and the Hope Creek Nuclear Plants. PJM's objectives of the solicitation were as follows:

- Generate maximum power (3,818 MW total) from all Artificial Island units without a minimum MVAR requirement. Full maximum power must be maintained under both baseline and all N-1 500 kV line outage conditions in the Artificial Island area. Voltages must be maintained within established operating limits and stable for all NERC Category B and C contingencies. N-1-1 contingencies do not need to be applied in addition to the N-1 500 kV outage condition in the Artificial Island area.
- Ensure maximum Artificial Island MW output is not affected by the simultaneous outage of power system stabilizers of Salem Unit 2 and Hope Creek. The Salem Unit 1 power system stabilizer is assumed to be on for all scenarios.
- Reduce operational complexity.
- Improve Artificial Island stability.
- Maintain PJM System Operating Limits (SOLs).

PJM started seeking proposals for the area on April 29, 2013. The window for submitting proposals ended June 28, 2013. Factors reviewed by PJM included system performance, constructability and cost. To evaluate system performance, PJM performed transient stability, voltage, thermal and short-circuit analysis and compared the results against the mandatory NERC and PJM reliability standards and requirements. PJM evaluated constructability by assessing project cost, schedule, siting, permitting, ROW acquisition, project complexity and operational impacts. For this analysis, PJM used third party contractors who had the necessary subject matter expertise to evaluate proposals.

4.3.1.2 Responses

PJM received 26 proposals from 7 different entities. The cost of the proposals ranged from $100 million to $1.55 billion. The following table shows the entities submitting proposals, the number of proposals submitted and the cost range of their proposals.

Bidder	# of Proposals	Cost Range $M US	Comments
Virginia Electric	3	$126 to $133	Virginia Electric is a vertically integrated utility and is a subsidiary of Dominion, an investor owned utility (IOU).
Transource	4	$123 to $994	Transource is jointly owned by AEP and Great Plains Energy, both are vertically integrated IOUs.
First Energy	1	$410	First Energy is a vertically integrated IOU.
PHI/Exelon	1	$475	Exelon and PHI are both vertically integrated IOUs.

LS Power	2	$116 to $170	LS Power is a privately held transmission and generation developer.
Atlantic Wind	1	$1,012	Atlantic Wind is a partnership between an experienced developer (Trans-Source), Google, Bregal Energy & Marubeni Corp (Japanese investment bank). Atlantic Wind has also received funding from Macquarie Capital.
PSE&G	11	$692 to $1,548	PSE&G is the incumbent and is a vertically integrated IOU.

The proposals varied from the addition of 500 MVAr of SVCs to the addition of EHV transmission lines (either overhead or underground) near the Salem substation to an HVDC line near artificial island to extensive rebuilds of the 500kV system around artificial island.

Because this was an early in competitive process, PJM had to performed detailed analysis on all proposals to evaluate their performance. To facilitate this analysis, PJM categorized the various proposals into four groups:

- Four proposals for southern Delaware River crossings – both overhead and submarine – that terminated at the existing 230 kV system in Delaware.
- Four proposals for new 500 kV lines from either Hope Creek or Salem substations to the Red Lion 500 kV substation in northern Delaware.
- The proposal comprising a +750/-375 MVAR SVC and thyristor controlled series compensation devices near New Freedom.
- Seventeen proposals with cost estimates more than twice that of the others.

The proponents did present some advanced technology options as well as innovative construction techniques. Two proposals, one from Dominion and one from Atlantic Wind, included SVC's in its project proposal. One proposal (Atlantic Wind) included a DC 320 kV DC line addition into the Salem/Hope Creek area. One proposal (LS Power) included a directional boring approach to cross the Delaware River to address minimize environmental impacts and to speed up permitting.

4.3.1.3 Awardee & Basis for Award

PJM selected the LS Power proposal to put in a 230kV underground circuit between the Salem substation and a new Silver Run substation that will be created by tapping the Cedar Creek to Red Lion 230 kV and Catanza to Red Lion 230 kV lines. PJM indicated that LS Power's proposed construction technique and cost containment model provided significant advantages over other proposals. From a constructability perspective, PJM felt that utilizing horizontal directional drilling techniques could mitigate permitting risks associated with crossing the Delaware River. Additionally, PJM stated that the LS Power proposal provides greater cost certainty with fewer exclusions to cost commitment compared to the other proposals.

The LS Power cost commitment included the following:

- Obtaining permits and other governmental approvals
- Acquiring land and land rights
- Performing environmental assessments or mitigation activities
- Design and engineering
- Procurement of equipment, supplies and materials

This cost containment was applied to site clearing, equipment assembly and erection, testing and commissioning. It was also applied to all overhead, submarine or horizontal directional drilling river crossing portions of their project.

Costs excluded from the LS Power commitment included the following:

- Escalation, taxes, and financing (e.g. AFUDC) costs. Escalation of the cost commitment would be tied to an industry standard index.
- Additions and modifications to the project scope due to:
    - Material change in the enforcement, interpretation of application of any statue, rule, regulation, order or other applicable existing law
    - Breach or default by PJM of its obligations under the Designated Entity Agreement
    - Request by PJM to delay or suspend project activities
    - Breach, default, interference or failure to cooperate by any Transmission Owner in connection with the Interconnection Coordination Agreement or interconnection agreement
    - Ongoing project maintenance and operations costs.

In addition to LS Power's 230 kV line, PJM also added an SVC to the final recommendation to provide reactive margin necessary to mitigate transient stability issues identified in their analysis. This SVC (along with the 500/230 kV transformer addition at Salem substation) were awarded to the incumbent, PSE&G. There is no indication that there was any competitive analysis involved in PJM's decision to award the SVC to PSE&G. Finally, PJM also directed the utilities in the area to upgrade their relay communication to high speed, optical grounding wire to decrease clearing times in the area. PJM designated these enhancements to PSE&G, PHI and FirstEnergy.

4.3.1.4 Counter Factual Assessment

The incumbent is PSE&G, one of the seven entities submitting proposals. Therefore, in the absence of a competitive transmission process, it is likely that PSE&G would have developed one of the fourteen projects that PSE&G submitted to PJM during the artificial island solicitation window.

The capital cost for each of the proposals submitted by PSE&G was significantly higher than the final recommendation. The lowest cost proposal by PSE&G was for the addition of two new 500kV lines in the area. Both of these lines were overhead lines and avoided crossing the Delaware River. The cost estimate for these projects was 2.5 times greater than the cost estimate for the final, approved project. PSE&G estimated the cost of adding the two 500kV overhead lines to be $692 million, which compares to the total estimated cost of $275.5 million for the final approved project.

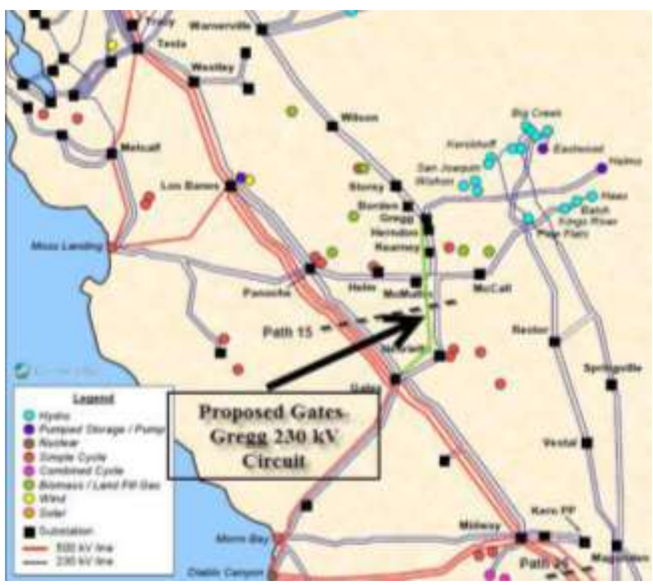
Offsetting the significant cost savings of the project package identified by PJM, it is interesting to note that all of PSE&G's proposals involved 500kV, overhead facilities. Perhaps this because PSG&E is the incumbent and has detailed knowledge of the geography in their area and, therefore, they wished to avoid the risks associated with crossing the Delaware River at 230kV. Because they control much of the ROW, a case could be made that 500kV development may be less risky than LS Power's 230 kV river crossing, which has no ROW or firsthand experience in the area.

4.4 Recent Solicitations - CaISO

4.4.1 Gates Gregg

In the 2012-2013 Transmission Plan, the ISO identified a reliability project with additional policy and economic benefits for a 230 kV transmission line between the PG&E owned Gates and Gregg 230 kV substations, as depicted the figure. The Gates-Gregg 230 kV Line is to be constructed as a double circuit 230 kV line with one side strung. The ISO estimates that the cost of the 230 kV line will be between $115 and $145 million. The analysis identified the need for the Gates-Gregg 230 kV line in the 2022 timeframe as indicated in the transmission plan.

Figure 4.9 – Proposed Gates to Gregg circuit



4.4.1.1 Project Objectives & Solicitation Background

This project will facilitate future development requirements to supply load or integrate renewable generation in the area while minimizing the future right of way requirements compared to single circuit development. CAISO opened the bid window following the approval of the transmission plan where the window to submit proposals to finance, construct, and own the Gates-Gregg 230 kV Line is open from

April 1, 2013 through June 3, 2013. On August 13th 2013 CAISO has posted the list of qualified potential project sponsors that will be further considered in the selection process to finance, construct, and own the Gates-Gregg 230 kV transmission line element. On November 13th, 2013 CAISO selected the partnership of PG&E and MidAmerican Transmission to implement the project.

4.4.1.2 Responses

A. Types of Organization

There are 5 qualified bidders who have responded to the solicitation process. Out of the 5 bidders 3 bidders are private developers, one bidder is a public – private partnership and one incumbent IOU in partnership with another IOU. Private developers are Elecnor Inc subsidiary of Elecnor a public company traded on the Madrid Stock Exchange, Isolux Infrastructure subsidiary of Isolux Infrastructure Netherlands and G2G ProjectCo LLC affiliate of Trans Bay Cable LLC (TBC) a company owned and managed by SteelRiver Infrastructure Partners LP. Pattern Energy Group LP and the City of Pittsburg is a public-private partnership between Pattern Energy Group (Private Developer) and City of Pittsburg a Public Agency. PG&E is the only incumbent TO in the solicitation process and partnered with MidAmerican Transmission an IOU in conjunction with Citizens Energy Corporation a non-profit organization.

B. Cost Estimates

The following cost components were included into the FERC filings of the projects. The estimated cost components for the Project, based upon assumptions listed in the Approved Project Sponsors' bid submittal, are summarized as follows (in 2013 dollars):

Table 4.10 Approve sponsor estimated cost components

Transmission Line Costs	Costs
Environmental & Related	$29,897,186
Engineering	5,130,158
Civil Works	8,017,329
Materials	41,609,109
Equipment	4,275,909
Construction	23,432,108
Construction Management	3,406,780
Other	162,464
Subtotal – Base Cost	$130,075,380
AFUDC	$23,528,286
Property Tax	3,418,100

Total	$157,021,766

The specifics of each proposal was kept confidential. However, since this was a late entry competition, all of the bidders were bidding on the same project.

4.4.1.3 Awardee & Basis for Award

PG&E and MAT partnership was awarded the project. PG&E/MAT's proposal was better with respect to the following key selection factors: (1) possession of existing rights-of-way that could contribute to the project and experience in acquiring rights-of-way to facilitate approval and construction of the project, (2) financial capabilities, and (3) overall licensing, construction, operation, and maintenance capabilities, as well as extensive and NERC compliance experience and capabilities as the result of their ownership of extensive transmission systems, including an extensive system in California. Finally, it is important to note that no project sponsor agreed to a specific, binding cost cap in its application.

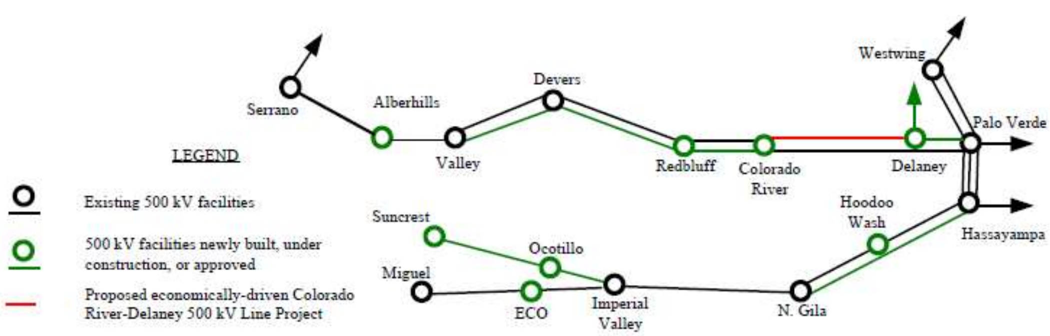
4.4.1.4 Counter Factual Assessment

PG&E is an incumbent and won the proposal. This was one of the first projects awarded by CAISO, ROW was a decisive factor. No price caps were included by any bidder, therefore, it is likely this project would have been developed at around the same cost in the absence of competition.

4.4.2 Delaney Colorado River

In the 2013-2014 Transmission Plan, the ISO has identified an economically-driven need for a 500 kV transmission line between SCE owned Colorado River 500 kV substation and APS owned Delaney 500 kV substation, as depicted below. The estimated cost of the proposed 500 kV line is $300 million in 2014 dollars. This estimated cost does not include facilities necessary at the Delaney and Colorado River substations that will be installed by the owners of those substations, because these facilities are not included in the scope of this competitive solicitation. This cost estimate does include the requisite transmission line series compensation, which is within the scope of the competitive solicitation scope.

Figure 4.11 – Delaney to Colorado transmission line (red)



4.4.2.1 Project Objectives & Solicitation Background

On July 1st 2014 CAISO posted the solicitation for the project and on September 3rd 2014 conducted the web conference and presented the selection factors and specifications for the project.

On April 15th 2015 CAISO has posted the list of qualified potential project sponsors that will be further considered in the selection process to finance, construct, and own the Gates-Gregg 230 kV transmission line element.

On July 10th 2015 CAISO has posted the selected sponsor for the project as DCR Transmission, LLC.

4.4.2.2 Responses - Types of Organization

There are 5 validated bidders who participated in the solicitation:

- California Transmission Development, LLC is a private developer a subsidiary of LS Power
- NextEra Energy Transmission West, LLC is a transmission subsidiary of NextEra Energy Services which is a IOU.
- DCR Transmission LLC – Financial developer partnership between Abengoa Transmission & Infrastructure, LLC and affiliate of Starwood Energy Group Global, Inc.
- Duke-American Transmission Company (DATC) – Partnership among different entities Duke ATC (IOU), Western Area Power Administration Desert Southwest Region (Public Agency) and Citizens Energy Corporation(Non Profit). WAPA is the incumbent in this partnership.
- TC/SCE – Partnership between Trans Canyon DCR, LLC an affiliate of Berkshire Hathaway and incumbent IOU Southern California Edison Company.

The specifics of each proposal was kept confidential. However, since this was a late entry competition, all of the bidders were bidding on the same project.

4.4.2.3 Awardee & Basis for Award

Although the proposals of the other project sponsors have certain slight advantages over DCRT's proposal with regard to other selection factors and qualification criteria, the ISO has concluded that none of these advantages is sufficient (either individually or in aggregate) to outweigh the significant advantage of DCRT's proposal with regard to cost containment and producing materially lower project costs to the benefit of ratepayers. The ISO has determined that, given the specific nature of this project and taking into account the key selection factors, the overall advantage goes to DCRT primarily because -

- DCRT's proposal includes the lowest projected revenue requirements of all the project sponsors' proposals, which are significantly less than the nearest project sponsor's proposal,
- DCRT's binding cost containment proposal covers capital costs and return on equity,
- DCRT's proposed capital cost containment limits cover up to a specified amount in route risk, which the ISO's expert consultants determined to be low, particularly in terms of potential cost escalation, and

- Although the proposals of other project sponsors are slightly better than DCRT's proposal with regard to other selection factors and qualification criteria, the ISO determined that DCRT is qualified to complete the project.

The key cost containment and cost cap measures that contributed for the selection of DCRT are:

- Cost containment limits in its proposal include engineering, procurement, and construction (EPC) construction costs, development costs, DCRT general costs, allowance for funds used during construction (AFUDC), and financing fees.
- No recovery of costs of construction work in progress (CWIP)
- No ROE that includes a 100 basis point adder
- No use of accelerated depreciation, and pursuit of tax incentives/reductions
- Capital costs were significantly below the capital costs of CTD, NEET West, and TC/SCE

CAISO identified Cost Containment as a key selection factor because the justification for this project is solely based on economic benefits to ratepayers, and CAISO considers commitment to robust binding cost containment measures to be the most effective way in which the ISO can ensure that a project is developed in an efficient and cost-effective manner.

4.4.2.4 Counter Factual Assessment

Two of the proposals were submitted by partnership which included incumbents. These are

- DATC proposal involved incumbent Western Area Power Administration Desert Southwest Region
- TC/SCE involved incumbent Southern California Edison Company

Key Factor Cost Containment Comparison

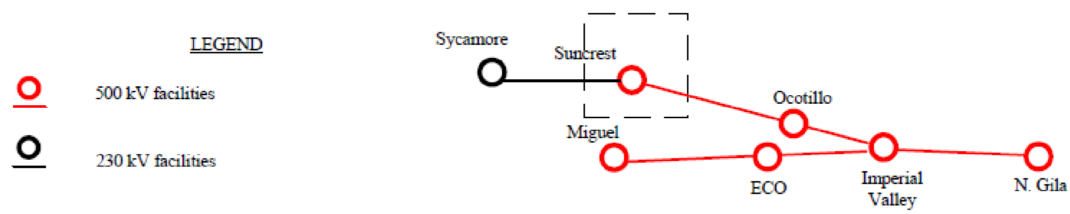
- The WAPA proposal with DATC did not offer a binding cost containment proposal, stating that firm cost containment limits expose the project sponsor to unlimited financial risks.
- The capital costs underlying TC/SCE's cost containment proposal are equal to its estimate for capital costs, including contingency. The cost containment limits in TC/SCE's proposal are significantly higher than DCRT's cost containment limits.
- Also, TC/SCE did not propose to include ROE within its cost containment limits, but it agreed to forego ROE incentives except for the 50 basis-point-adder for participation in a regional transmission organization.

Therefore, there likely would have been no cost containment included in the developed project. It is also likely that all basis points would have been included in final revenue requirements, resulting in higher charges to the customers.

4.4.3 Suncrest 230 kV 300 MVAr SVC

In the 2013-2014 Transmission Plan, the ISO has identified a policy-driven need for a 300 MVAr dynamic reactive power support connecting to the Suncrest 230 kV bus SDG&E will design, engineer, install, own, operate, and maintain the necessary equipment additions within Suncrest substation. A 230 kV tie-line from the dynamic reactive power support project to Suncrest Substation will be the responsibility of the project sponsor. The approved project sponsor will own, operate and maintain all transmission facilities from the reactive support up to and including the terminal line structure.

Figure 4.12 – Suncrest interconnections



4.4.3.1 Project Objectives & Solicitation Background

CAISO posted the description and functional specifications for competitive solicitation on April 15th 2014 for the Suncrest Reactive Power Project. On August 5th 2014 validated sponsors list was posted by CAISO for the project. Project sponsor selection report for the Suncrest project was released on January 6th 2015.

4.4.3.2 Responses - Types of Organization

There are only two bidders for this project, one is an incumbent who owns the station where the SVC is installed that is San Diego Gas and Electric an IOU. The other bidder is a transmission subsidiary of the IOU NextEra West a subsidiary of NextEra Energy Inc.

4.4.3.3 Awardee & Basis for Award

Analysis by CAISO determined that, given the specific nature of this project and taking into account the key selection factors, the slight overall edge goes to NEET West primarily because NEET's proposed binding cost containment measures were more robust since NEET agreed to a materially lower cap on capital costs, which meant that NEET assumed more cost increase risk than SDG&E.

Although SDG&E's proposal is better with respect to meeting schedule because SDG&E does not need a Certificate of Public Convenience and Necessity (CPCN) and is utilizing existing property rights, schedule risk is not as critical here because there is no imminent, identified reliability need. And even though SDG&E's proposal has an advantage in the use of existing rights-of-way, it did not result in SDG&E proposing a lower cost cap. Also, NEET West has already secured an option to purchase property on which to locate the SVC as well as easements for the transmission line (except for SDG&E property), and the overall scope and size of the project is not particularly extensive or complex. As a result, CAISO selected NEET West to develop the Suncrest 230 kV 300 MVAr dynamic reactive power support project pursuant to the proposal set forth in its project application.

4.4.3.4 Counter Factual Assessment

In case of no competition, SDG&E would have been assigned the project to develop at the proposed costs.

4.4.4 Miguel 500 kV Bus

In the 2013-2014 Transmission Plan, the ISO has identified a reliability-driven need for a 375 MVAr reactive power support connecting to the Miguel 500 kV bus. SDG&E will design, engineer, install, own, operate, and maintain the necessary equipment additions within Miguel substation. A 500 kV tie-line from the reactive power support project to Miguel Substation will be the responsibility of the approved project sponsor. The estimated costs for the solicitation are in the range of $30 to $40 Million.

4.4.4.1 Project Objectives & Solicitation Background

On May 1st 2014 CAISO posted the solicitation of Miguel 500 KV bus as well as selected the sponsor for the Miguel 500 KV bus.

4.4.4.2 Responses - Types of Organization

There is only one bidder in the project which is the incumbent IOU San Diego Gas & Electric.

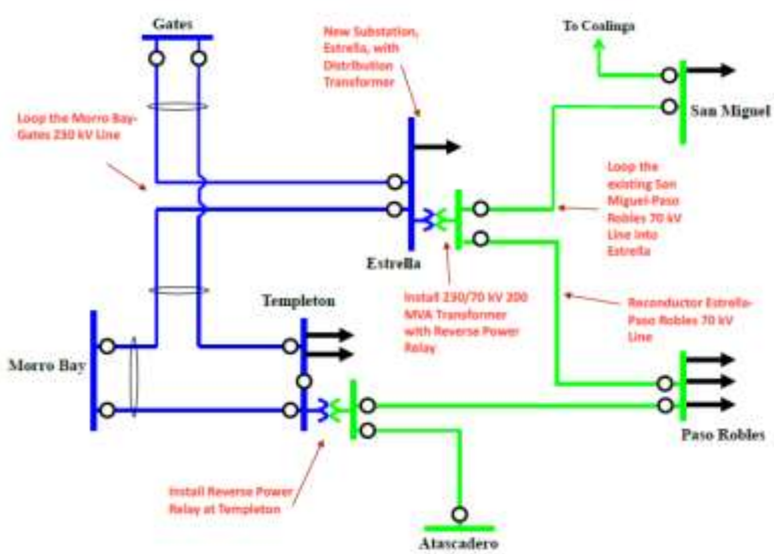
4.4.4.3 Awardee & Basis for Award

CAISO posted during the posting of the solicitation the project has been awarded to SDG&E.

4.4.5 Estrella Substation

In the 2013-2014 Transmission Planning Cycle, the ISO approved the construction of a reliability-driven *Estrella Substation Project* in the Los Padres Division of the PG&E service territory. The scope of this project is to construct a new 230/70 kV substation, Estrella, approximately 5 miles east of the existing Paso Robles Substation. The Estrella 230 kV bus will be looped into the Morro Bay-Gates 230 kV line. A new 230/70 kV transformer will be installed at the Estrella substation. In addition, a 45 MVA 230/12 kV distribution transformer will be installed as a part of the project.

Figure 4.13 – Proposed changes at Estrella substation



The facilities in the Estrella substation project that are considered eligible for competitive solicitation are the 230 kV bus-work and termination equipment, and the 230/70 kV transformer bank. The 70 kV bus-work, termination equipment and modifications to existing facilities are not eligible for competitive solicitation. In addition the 230/12 kV distribution transformer, distribution bus-work and termination equipment and modifications to existing facilities are not eligible for competitive solicitation.

4.4.5.1 Project Objectives & Solicitation Background

The project will mitigate the thermal overloads and voltage concerns identified in the Los Padres 70 kV system, specifically in the San Miguel, Paso Robles, Templeton, Atascadero, Cayucos and San Luis Obispo areas following a Category B contingency due to loss of either the Templeton 230/70 kV #1 Bank or the Paso Robles-Templeton 70 kV Line. These two Category B contingencies put approximately 60-70 MW of load at Paso Robles at risk by activating the existing Paso Robles UVLS during summer peak conditions to alleviate the thermal and low voltage concerns. Also, a Category C3 contingency condition involving loss of Morro Bay-Templeton and Templeton-Gates 230 kV lines results in thermal overloads and low voltages in the underlying 70 kV system. With the additional source from the Gates 230 kV system, the Estrella Substation Project will provide robust system reinforcement to the Paso Robles and Templeton 70 kV system operations.

Solicitation of the project was opened on June 26th 2014 and the validated sponsor list was posted on November 10th 2014. The project sponsor report selecting NextEra West as developer was issued on March 11th 2015.

4.4.5.2 Responses

A. **Types of Organization –** There are four bidders in the solicitation process of which one of the bidder is incumbent. The bidders are
    - Brookfield California Transmission, LLC is private developer
    - Golden State Transmission, LLC (Golden State) is partnership between IOU Edison Transmission LLC and developer Transource Energy, LLC
    - NextEra Energy Transmission West is transmission subsidiary of NextEra Energy Services
    - Pacific Gas and Electric Company (PG&E) is the only incumbent vertically integrated IOU

B. **Cost Estimates (if available) –** The ISO estimates that the proposed Estrella Substation Project in its entirety will cost $35 million to $45 million in 2014 dollars. The proposed in-service date of the project is May 2019.

4.4.5.3 Awardee & Basis for Award

The ISO has determined that, given the specific nature of this project and taking into account the key selection factors, the overall edge goes to NEET West primarily because (1) NEET West proposed a reasonable binding cost cap, and (2) NEET West's interconnection costs are materially lower than the interconnection costs of the other project sponsors. NEET West's site and physical project do not present any inherent material cost disadvantages or distinct risks. NEET West's proposal is comparable to or slightly better than the proposals of Brookfield CalTrans and Golden State with regard to all selection factors and qualification criteria discussed above. Although the ISO has determined that PG&E's proposal is slightly better than NEET West's proposal with regard to two selection factors and two qualification criteria, this results from a single PG&E advantage -- having a more local O&M organization, an advantage with respect to response time for field operations and emergency situations, and spare equipment compared to the other project sponsors. This advantage for PG&E does not outweigh NEET West's cost cap and material interconnection cost advantages for the Estrella Substation project.

4.4.5.4 Counter Factual Assessment

PG&E is the only incumbent bidder and its proposal did not include binding cost cap or binding cost containment measures. PG&E did not offer cap on O&M costs, but PG&E indicated that it will be relying on its existing O&M organization and infrastructure for purposes of O&M at the Estrella Substation. In case of no competition PG&E would have built the project at the proposed costs which will be higher than the approved proposal.

4.4.6 Spring Substation Project

In the 2013-2014 Transmission Planning Cycle, the ISO approved the construction of a reliability-driven Morgan Hill Area Reinforcement Project in the San Jose Division of the PG&E service territory. The project will provide the Morgan Hill Area, as well as the San Jose Area, with a more reinforced 230 kV source from the new Spring Substation. The scope of this project includes:

- Construct a new 230/115 kV substation, Spring Substation, west of the existing Morgan Hill Substation.
- Install a new 230/115 kV 420 MVA transformer at Spring Substation.
- Loop the existing Morgan Hill-Llagas 115 kV Line into Spring 115 kV bus using a portion of the idle Green Valley-Llagas 115 kV Line Right-of-Way.
- Reconductor the Spring-Llagas 115 kV Line with bundled 715 Al or similar.
- Loop the Metcalf-Moss Landing No.2 230 kV Line into the Spring Substation 230 kV bus

The facilities in the Morgan Hill Area Reinforcement project that are eligible for competitive solicitation are the 230 kV bus-work and termination equipment, and the 230/115 kV transformer at Spring Substation.

4.4.6.1 Project Objectives & Solicitation Background

This project will mitigate thermal and voltage violations. These violations arise following the loss of the Llagas-Gilroy Peakers 115 kV Line and either one of the 115 kV Lines heading north to Metcalf Substation.
On June 26th 2014 CAISO solicited the projects and on November 10th 2014 posted the qualified sponsor list. The final project sponsor report is posted on March 11th 2015.

4.4.6.2 Responses

A. Types of Organization – There are three bidders in the solicitation process of which one of the bidder is incumbent. The bidders are:

- Brookfield California Transmission, LLC is private developer

- NextEra Energy Transmission West is transmission subsidiary of NextEra Energy Services
- Pacific Gas and Electric Company (PG&E) is the only incumbent vertically integrated IOU

B. Cost Estimates (if available)

The ISO estimates that the proposed *Morgan Hill Area Reinforcement Project* in its entirety will cost between $35 million and $45 million in 2014 dollars. The proposed in-service date of the project is May 2021.

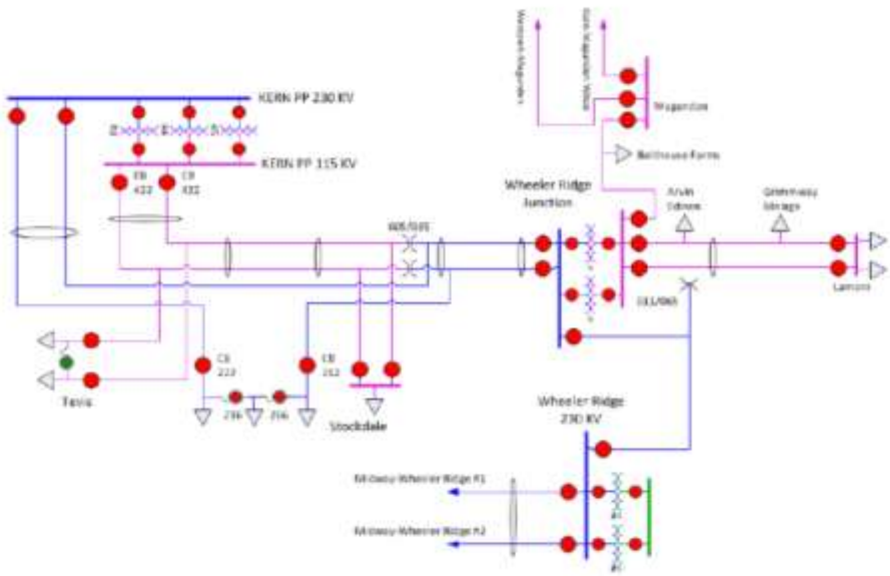
4.4.6.3 Awardee & Basis for Award

PG&E is the incumbent and the winner of this project. The ISO has determined that, given the specific nature of this project and taking into account the key selection factors, the slight overall edge goes to PG&E primarily because (1) PG&E is in the best position to construct, operate, and maintain the project in the most efficient and cost-effective manner, with the least potential risk, and (2) with respect to this reliability project, it is in the best position to respond to field operations issues and emergency situations due to the close proximity and size of its maintenance headquarters and its existing spare parts inventory. PG&E's proposal is comparable to or slightly better than the proposals of Brookfield CalTrans and NEET West with regard to all but two of the eleven selection factors discussed above. The ISO considers PG&E's slight advantage with regard to selection factors 24.5.4(a) and (h) and qualification criteria (a) (a key selection factor) and (e) due to the close proximity and size of its maintenance headquarters and its existing spare parts inventory, including transformers, to be a more significant advantage in the selection process for this reliability project. Again, all project sponsors submitted strong proposals, and the ISO considers this decision to be very close. However, the ISO concludes that NEET West's cost advantage with respect to interconnection costs will more than be offset by PG&E's lower capital costs (due to the significant differences between the two sponsors' substation sites) and O&M costs. PG&E's proposal also presents fewer risks given the nature of its site. Particularly recognizing that this is a reliability project, PG&E's proposal also has the benefits of the close proximity and size of its maintenance headquarters and its existing spare parts inventory, including spare transformers. This can help address any future reliability, operational, or other unexpected problems.

4.4.7 Wheeler Ridge Junction Substation

In the 2013-2014 Transmission Planning Cycle, the ISO approved the construction of a reliability-driven Wheeler Ridge Junction Substation Project in the Kern Division of the PG&E service territory. The facilities in the Wheeler Ridge Junction substation project that are eligible for competitive solicitation are the 230 kV bus-work and termination equipment, and the 230/115 kV transformers. The 115 kV bus-work and termination equipment and modifications to existing facilities are not eligible for competitive solicitation.

Figure 4.14 – Proposed changes at Wheeler Ridge substation



4.4.7.1 Project Objectives & Solicitation Background

The project will mitigate the thermal overloads and voltage concerns identified in the Wheeler Ridge 230 kV system, specifically in the area of the CDWR pumps, following a Category C1 or C2 contingency due to loss of either the Midway 230kV Bus 1D or Midway 230kV CB642 fault. This project will also mitigate several 115kV concerns in the Kern PP 115kV area. On June 26th 2014 CAISO solicited the projects and on November 10th 2014 posted the qualified sponsor list. The final project sponsor report is posted on March 16th 2015.

4.4.7.2 Responses

A. ***Types of Organization***

There are four bidders in the solicitation process of which one of the bidder is incumbent. The bidders are

- Brookfield California Transmission, LLC is private developer
- Golden State Transmission, LLC (Golden State) is partnership between IOU Edison Transmission LLC and developer Transource Energy, LLC
- NextEra Energy Transmission West is transmission subsidiary of NextEra Energy Services
- Pacific Gas and Electric Company (PG&E) is the only incumbent vertically integrated IOU

B. Cost Estimates (if available)

The ISO estimates that the proposed *Wheeler Ridge Junction Project* in its entirety will cost between $90 million and $140 million in 2014 dollars. The proposed in-service date of the project is May 2020.

4.4.7.3 Awardee & Basis for Award

There were either no material differences or only slight differences among the project sponsors and their proposals with respect to most of the qualification criteria and selection factors. The ISO has determined that, given the specific nature of this project and taking into account the key selection factors, the slight overall edge goes to PG&E primarily because (1) PG&E is best positioned to construct, operate, and maintain the project in the most efficient and cost-effective manner for the life of the project, and (2) with respect to this reliability project, it is in the best position to respond to field operations issues and emergency situations due to the close proximity and size of its maintenance headquarters and its existing spare parts inventory.

More specifically, PG&E's proposal is slightly better than the proposals of NEET West and the other project sponsors with regard to four of the eleven selection factors, including two key selection factors, and two of the six qualification criteria, including one criterion that is also a key selection factor. NEET West's advantage with respect to the cost containment criterion is outweighed by PG&E's other advantages that are expected to result in overall lower costs for the life of the project, namely PG&E's use of land that is already in rate base, lower expected O&M costs, and lower interconnection costs. Also, recognizing that this is a reliability project, PG&E's proposal also has the benefits of the close proximity and size of its maintenance headquarters and its existing spare parts inventory, including spare transformers. This can help address any future reliability, operational, or other unexpected problems.

4.5 Recent Solicitations – Canada

4.5.1 Fort McMurray West 500 kV

The Fort McMurray West project included the following components:

- 500 kV Thickwood Hills substation (~25 km west of Fort McMurray)
- 100 km 500 kV AC single circuit transmission line from the new 500 kV Thickwood Hills substation to the new 500 kV Livock substation
- 500 kV Livock substation (adjacent to the existing 240 kV Livock substation)
- 400 km 500 kV AC single circuit transmission line from the new Livock 500 kV substation to the existing Sunnybrook substation

4.5.1.1 Project Objectives & Solicitation Background

The project supported the increase in electric load for the oil sand development in Northern Alberta. The AESO implemented Stage One of the Competitive Process, the Request for Expression of Interest (REOI), on May 9, 2013. Once it was determined that there was sufficient interest in the project, the AESO implemented Stage Two, the Request for Qualifications (RFQ), in July 2013. On January 17, 2014, AESO indicated that five organizations had been selected to participate in Stage Three, the Request for Proposals (RFP). On December 18, 2014 AESO indicated that it had selected Alberta PowerLine Limited Partnership to construct the Fort McMurray West project.

4.5.1.2 Responses

AESO indicated that there was interest from organizations from around the world to build the project, including Asia, Europe, South America and North America. Of the submissions, these five were selected from the RFQ responses provided:

1) **Alberta PowerLine –** owned by Canadian Utilities Limited and Quanta Capital Solutions Inc. Valard Construction LP would undertake design and construction work and ATCO Electric Ltd. would be responsible for operating and maintaining the transmission facilities.

2) **Athabasca Transmission –** owned by AltaLink LP and AEP Transmission Holding Company LLC. Burns and McDonnell Canada Ltd. and SNC Lavalin T&D would design and construct the facilities while AltaLink LP and AEP Transmission Holding Company LLC would be responsible for ongoing operations and maintenance.

3) **NorSpan Partners LP –** owned by EPCOR Utilities Inc. and LS Power Associates LP. Kiewit Energy Canada Corp. and Sargent & Lundy LLC would undertake design and construction work while EPCOR Utilities Inc. would be responsible for operating and maintaining the transmission facilities.

4) **TAMA Transmission LP –** owned by MidAmerican Energy Holdings Company and TransAlta. MidAmerican Energy Holdings Company (through its wholly owned subsidiary MidAmerican Transmission) would undertake design and construction work while TAMA Transmission would be responsible for ongoing operations and maintenance.

5) **TransCanada/Elecnor –** owned by TransCanada PipeLines Limited and Elecnor S.A. Elecnor would be responsible for the design and construction of the facilities while TransCanada PipeLines Limited would be responsible for operating and maintaining the transmission facilities.

The specifics of each proposal was kept confidential. However, since this was a late entry competition, all of the bidders were bidding on the same project.

4.5.1.3 Awardee & Basis for Award

AESO selected the Alberta PowerLine Limited Partnership for construction of Fort McMurray West.

The basis for the selection was that Alberta PowerLine Limited Partnership was the lowest cost bidder of the five qualified bidders. Alberta PowerLine Limited Partnership submitted a bid of $1.433 billion for the right to design, build, finance, operate and maintain the facility for a period of 35 years. This compares to the original, construction only estimate of $1.6 billion developed by the AESO.

4.5.1.4 Counter Factual Assessment

The incumbent is ATCO Electric, LTD which is owned by one of the partners in the Alberta PowerLine Limited Partnership. Therefore, in the absence of the Competitive Process, it is likely the incumbent would have developed a similar project. However, it is also likely that that focus of cost control would have been related to capital construction costs and would not have included a fixed cost for the 35 year life of the project, including O&M.

4.6 Insights into the Cost of Competition

Based upon Navigant's research, it appears that all ISOs have added both internal and external resources to support the competitive transmission processes. The initial costs spent by ISOs were mainly for legal services to support the detailed regulatory filings. Later the costs identified were to support the transmission planning side where new full time employees were added or external consultants were engaged to provide services.

4.6.1 Regional and Provisional Costs

Table 4.5 below describes the budget of some of the ISOs relevant to FERC 1000. All ISOs stated in their filings to FERC that the costs for the solicitation will be collected from the participants and an administrative fee is collected as deposit from each bidder. For this each ISO filing included deposits needed for the solicitation process.

Table 4.15 Budgeted costs by ISOs Competitor Costs

Description	SPP	NYISO	MISO
FTEs	5 FTEs	4.5 FTEs	3 FTEs
Budget	See Consulting Costs	See Consulting Costs	$1.4 M (Likely includes FTEs salary and consulting)
Consulting Costs	$1.6 M (IEP + other consulting)	$80,000 (2016 Budget)	

4.6.2 Competition Costs

Most of the costs incurred for the competitive solicitation processes are recovered by the ISOs through accrued costs after each solicitation which are included in the tariff adders. ISOs also typically charge a participation fee to help defray costs paid by transmission customers.

NYISO requests a non-refundable application fee of $10,000 and a study deposit of $100,000. These costs associated with solicitation are the responsibility of the applicants.

PJM collects a $50,000 study deposit, $20,000 of which is non-refundable and $30,000 of which will only be used if the applicant's project passes the initial screening and moves into detailed analysis.

MISO requires an initial deposit of $100,000.00 in conjunction with the submission of each Proposal prior to the Proposal Submission Deadline.

CAISO - Each Project Sponsor will pay a deposit of $75,000 to the CAISO with the submission of each Project Sponsor application project proposal. Separate deposit is required for each solution for which a Project Sponsor submits an application. Within 75 days of project sponsorship CAISO will determine each Project Sponsor's pro rata share of the costs that the CAISO incurred in determining the qualified Project Sponsors for that solution and will refund to each Project Sponsor that the CAISO did not include in the list of qualified Project Sponsors. Table 4.6 shows the accrued costs for the projects that have been approved so far.

Table 4.16 CAISO Accrued project costs

Year	Project	Number of Bidders	Total Costs
2013 - 2014	Delaney Colorado river	5	$492,901.4
2013-2014	Suncrest 230 kV 300 MVAr SVC	2	$260,572.54
2013-2014	Miguel 500kV bus.	1	$15,056
2013-2014	Estrella substation	4	$206,104.36
2013-2014	Spring substation project	3	$165,911.76
2013-2014	Wheeler Ridge Junction substation	4	$151,179.24

SPP collects deposits from the bidders based on the cost of the project. For small Project (less than $10 million) a deposit of $10K is collected. For medium Project which cost between $10 million and $100 million a deposit of $25K is collected. For large Project which is greater than $100 million a deposit of $50K is collected. IEP consultation costs for the evaluation process are separate and are collected as part of accrued costs.

ISONE requires $100,000 deposit for Phase One Proposal submittal to cover the cost of analyses for Phase One and Phase Two. ISO-NE will conduct a preliminary feasibility review of each Phase One Proposal to determine, among other things, whether the Qualified Sponsor provided sufficient quality data, the proposed project meets the needs described in the Needs Assessment, and the project is technically practical.

4.7 Conclusions

Certain trends are evident from the North American experience.

First, in all but one instance, there have been qualified entities bidding on project solicitations. The one instance, Miguel substation, was a small project and one of the first projects that went into the competitive transmission process for CaISO.

Second, it appears that over time competition is starting to both bring down costs and encourage cost containment. In two large projects, Artificial Island and Fort McMurray West, the cost savings achieved appear significant. In the case of Artificial Island, the winning package was $417 million (US) less than the least cost package proposed by the incumbent (PSE&G). In the case of Fort McMurray West, AESO indicated the total life cycle cost of the winning bid was $370 million (CA) less than the original estimated construction cost.

Third, we have seen that competition has resulted in innovative solutions and construction techniques being proposed. For example, the winning bid for Artificial Island included directional boring to control costs and manage environmental risks when crossing the Delaware River. Also, SVCs of different sizes have been proposed as have DC facilities.

Fourth, it should be noted that system reliability has been maintained since these projects are driven by NERC Planning Criteria and the impacts of the project must satisfy these mandatory requirements. However, the public record for these projects does not provide sufficient detail on the proposals to get insights yet into the variation of construction standards and the potential long term impacts.

Fifth, based on public data provided by three ISOs there are extra costs incurred to operate these competitive processes. It was noted that FTE impacts of competitive solicitation range from 3 to 5 FTEs. Budgets for external support range from approximately $150k to $1.7M per solicitation.

5. Evidence from the Australian market

5.1 Market Overview and Situation Analysis

Energy markets in Australia are generally characterised by competitive wholesale and retail markets. This is due in large part to a history of progressive structural and institutional reform that created the framework for competition to develop today. While regulated network services are provided only by regulated businesses, market reforms are opening up formerly monopoly network services to competition.

Figure 5.1. Australia's National Electricity Market

In Australia, there are transmission networks in each state and territory, with cross-border interconnectors that link some networks. The National Electricity Market (NEM) interconnects five regional market jurisdictions - Queensland, New South Wales, Victoria, South Australia and Tasmania. The transmission networks in Western Australia and Northern Territory are not connected to the NEM nor to each other[1].

The NEM supplies about 200 TWh of energy to businesses and households each year. With about 40,000 km of transmission lines, the NEM is the longest alternating current system in the world. Compared to Europe and North America, the system is long and linear and can be more costly to upgrade on a per km basis because of the long distances and lower density[2].

5.1.1 Market structure

Historically, government utilities ran the entire electricity supply chain in all states and territories. In the 1990s governments began to separate the generation, transmission, distribution and retail segments into stand-alone businesses. Generation and retail were opened up to competition, but at the time this approach was not appropriate for the transmission and distribution networks, which became regulated monopolies[3].

Since then, Victoria and South Australia has privatised their transmission networks, but other jurisdictions have retained government ownership. Singapore Power International has a 51% stake in Victoria's transmission network, SP AusNet. A consortium led by Queensland government owned

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[1] Australian Energy Markets Operator. "About the National Electricity Market (NEM)". November 2015. Available at: http://www.aemo.com.au/About-the-Industry/Energy-Markets/National-Electricity-Market

[2] Ibid.

[3] Australian Competition and Consumer Commission. "Reinvigorating Australia's Competition Policy". June 2014. Available at: http://www.accc.gov.au/system/files/Harper%20Review%20-%20Issues%20Paper%20-%20ACCC%20Submission%20-%20FINAL%20(for%20website)%20-%2025%20June%202014%20(2).pdf

Powerlink, owns South Australia's transmission network. YTL Power Investments, part of a Malaysian conglomerate, and Hastings Fund Management are minority owners[4].

Since the commencement of the NEM, private investors have constructed three interconnectors - Murraylink, Directlink and Basslink. All have since changed ownership. Energy Infrastructure Investments owns Murraylink and Directlink. A trust with links to Singapore Power International acquired Basslink in 2007[5].

5.1.2 Transmission competition

Competition in transmission networks in Australia is currently limited to the construction and ownership of assets. The prevailing model for the provision of network services in the NEM outside of Victoria is for state-designated Transmission Network Service Provider (TNSP) monopolies to manage the process directly and exclusively with connecting parties.

In Victoria, a unique transmission network structure has been set up in which asset ownership is separated from planning and investment decision making. SP AusNet owns the state's transmission assets, but the Australian Energy Market Operator (AEMO) plans and procures network services, including augmentations to the shared network. The construction of a network augmentation to the shared network can be undertaken by a variety of construction providers. The maintenance and operation of a connection asset must be delivered by a registered TNSP. Under this arrangement, interstate transmission network service providers (TNSPs) and other suitably qualified parties can compete with SP AusNet for the rights to build and own contestable augmentations[6].

There are limitations that prevent competitive transmission from being rolled out nationally. It will require an independent party with sufficient technical expertise to oversee its management. Even if a generator was willing to obtain a transmission license and build and own transmission assets, it would be difficult to do so without legislative changes[7].

5.2 *Customer Impacts*

The most immediate opportunities for transmission competition are in Victoria, facilitated by the state's current arrangements allowing for competitive tendering for connection assets.

A recent competitive tender to upgrade the Heywood interconnector between Victoria and Australia attracted bids from three TNSPs: SP AusNet, Transmission General Holdings Australia (TGHA) and TransGrid. These bids were subjected to a regulatory investment test for transmission (RIT-T) to identify the transmission investment option that would maximise net economic benefits for customers while

[4] University of Sydney. "Electricity Privatisation in Australia - A Briefing Note". October 2012. Available at: http://www.asu.asn.au/news/categories/energy/121011-privatisation
[5] Ibid.
[6] Australian Energy Regulator. "State of the Energy Market - Electricity Networks". 2013. Available at: https://www.aer.gov.au/system/files/Chapter%202%20-%20Electricity%20networks%20A4.pdf
[7] Australian Energy Market Operator. "Energy Network Regulation - Submission to Productivity Commission's Issues Paper". May 2012. Available at: http://www.pc.gov.au/inquiries/completed/electricity/submissions/sub032-electricity.pdf

meeting jurisdictional reliability standards. SP AusNet, Victoria's incumbent TNSP, presented a bid that yielded the highest net market benefits.

The table below shows the outcome of the Heywood RIT-T and modelled net market benefits in net present value terms for each credible option. Option 1b, SP AusNet's bid was ultimately selected as the winning bid based on the RIT-T assessment under different load and economic scenarios[8].

Option	*Market Benefit ($)*	*Costs ($)*	*Net Market Benefit ($)*[9]	*Ranking under RIT-T ($)*
1a) 3rd Heywood transformer + 100 MVAr capacitor + 132 kV works	222.2	57.8	164.4	4
1b) 3rd Heywood transformer + series compensation + 132 kV works	**270.5**	**79.8**	**190.8**	**1**
2a) Option 1a + 3rd South East transformer	227.5	70.7	156.8	6
2b) Option 1b + 3rd South East transformer	270.4	92.7	177.7	3
3) New Krongart-Heywood 500 kV interconnector + 275 kV works	303.0	212.2	90.8	8
4) 132 kV works + 100 MVA capacitor	155.6	30.6	125.0	7
5) 200 MW DM + Option 1b	304.1	147.1	156.9	5
6a) Control schemes + 500 kV bus tie	18.5	17.6	1.8	9
6b) Control schemes + Option 1b minus 3rd Heywood transformer	253.1	64.1	190.0	2

While this outcome was driven in part by SP AusNet's strong commercial position in Victoria, it is worthwhile considering whether SP AusNet had a structural advantage arising as a result of its position as the incumbent monopoly.

Further work has been carried out by AEMO and the Australian Energy Regulatory (AER) to assess whether it is in customers' best interests to retain the current competitive arrangements or whether

[8] Australian Energy Market Operator, ElectraNet. "South Australia – Victoria (Heywood) Interconnector Upgrade - RIT-T: Project Assessment Conclusions Report". September 2012. Available at: http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission/~/media/Files/Other/planning/RITTs/SA_VIC_Heywood_Interconnector_Upgrade_RIT_T_PACR.ashx

[9] *The net market benefit is the gross market benefit, weighted across all load and economic growth scenarios, minus the costs of each option in present value terms.*

change is required in the competitive process. These customer interest issues are summarised below within the framework of OFGEM's remit.

5.2.1 Promoting efficiency and economy

During the Heywood tender process SP AusNet submitted:

- A bid for the contestable works which leveraged the use of their existing assets.
- A separate offer for the non-contestable works outside of the competitive process.

In accordance with AEMO's policy of selecting the bid that offers the best value for money, SP AusNet's bid was selected. In opening the bid to competition, AEMO was able to procure the upgrade for $14 million less than forecast. This demonstrates that competitive pressure can lower costs[10].

In order to foster competition, it is important to ensure the process is fair and inclusive. In the Heywood tender, the incumbent operator won the bid. This outcome was not surprising given several competitive advantages that come with being the incumbent operator in the Australian market. For example, since only incumbent operators may provide non-contestable services, this allows them to submit bids which incorporate synergies between the contestable and non-contestable works, giving them a cost advantage over other parties. In the future, contestable TNSPs may decide that the chances of submitting a successful tender are too remote to justify the resources associated with participating in the tender process, thereby discouraging competition.

5.2.2 Innovative solutions

During the Heywood tender process, contestable TNSPs were limited in their ability to propose innovative solutions that made use of, or required amendments to, the existing shared network. In order to explore the feasibility of any potential solutions it would be necessary to enter into negotiations with SP AusNet. In practice, this would mean sharing commercially sensitive information with the same individuals that were preparing SP AusNet's Heywood bid. Other aspects of the procurement process further limited the ability for bidders to provide innovative solutions, for example, contact was prohibited between tenders to protect against collusion.

5.2.3 Reducing greenhouse gas emissions

The assessment of nine submitted bids to the Heywood tender determined that the majority of the options result in an increase in investment in low operating cost and low emission generation. The lower operating costs are reflected in the RIT-T assessment[11]. Therefore, for future bids, TNSPs can improve their competitive position by incorporating low carbon generation in their solutions. Competition can promote the reduction of greenhouse gases if the assessment framework rewards such initiative.

5.2.4 Protecting the public from dangers

The AEMC has been tasked with developing a nationally consistent framework for expressing, delivering and reporting on distribution and transmission reliability outcomes including faults and

[10] Ibid.

[11] Ibid.

customer interruptions. This paves the way for benchmarking the performance of incumbent TNSPs, setting standards and highlighting opportunities for new entrants[12].

5.2.5 Secure diverse and reliability long term energy supply

Structural and institutional reforms to Australian energy markets to date have delivered substantial benefits to consumers by providing them with greater choice of energy products and services and investment in generation and network capacity to support long term supply reliability and diversification.

The Australian Energy Market Commission (AEMC) has recently implemented rules that give the AER more power and flexibility in setting revenues for network businesses, including the rate of return network businesses are allowed to earn on their asset bases. This will flow through to network charges, lowering the cost of access and thereby promoting competition in downstream markets[13].

5.3 Lessons Learned

Since the Heywood tender, there have been several important market reviews conducted on the state of transmission competition in Australia.

- "Transmission Framework Review (TFR)" conducted by the AEMC outlining strategies for improving the development and provision of the transmission network in the NEM[14] and;
- "Public Inquiry on Electricity Network Regulation – Issues Paper" led by the Productivity Commission, examining the need to contain rising electricity prices and promote inter-regional competition in electricity supply and distribution[15].

Both reports feature submissions from energy users, system operators and transmission asset owners that highlight critical issues and perspectives on the current state of transmission competition in Australia. Key lessons learned with respect to customer interests are summarised below:

5.3.1 Strengthening competition and diversity of energy supply

Negating the competitive advantages enjoyed by the incumbent monopoly is one way of levelling the playing field by requiring them to behave as if they are a contestable bidder. Under this approach, it would be necessary to weigh the loss of efficiency benefits from leveraging the use of existing assets versus the benefits gained from enhanced competition.

The efficiency benefits may potentially be dwarfed by cost shifting on the part of the incumbent TNSP. For example, in the case of one network upgrade project, the cost estimate provided by the monopoly

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[12] Australian Energy Market Commission. "AEMC Response to the Competition Policy Review Issues Paper". July 2014. Available at: http://competitionpolicyreview.gov.au/files/2014/07/AEMC.pdf
[13] Ibid.
[14] Australian Energy Market Commission."Transmission Frameworks Review". April 2013. Available at: http://www.aemc.gov.au/Markets-Reviews-Advice/Transmission-Frameworks-Review
[15] Australian Government - Productivity Commission. "Electricity Network Regulation". June 2013. Available at: http://www.pc.gov.au/inquiries/completed/electricity/report

TNSP dropped upon realising that a competitive process would be adopted. The price drop was achieved by shifting costs from the TNSP's contestable bid to the non-contestable firm offer.

Another approach to levelise competition would be to change the regulatory framework so that the incumbent TNSP is required to give contestable bidders equal access to the declared shared network. This would give contestable bidders the opportunity to behave as if they are the incumbent TNSP. One drawback is that the incumbent TNSP would likely require compensation for the risks associated with sharing their assets with a third party. Accountability would also be less clearly defined.

5.3.2 Liability transfer

There are inherent conflicts in the ownership or operation of connection assets built by another party. The incumbent TNSP needs to be closely involved in the design and construction of the network asset in order to ensure the security and reliability of the shared network. Liability lies with the TNSP; transferring that liability would involve significant transaction costs which could outweigh any benefit from increased contestability.

Where appropriate, the TNSP in its operations should assume the required liability. Under its agreement with AEMO, it is required to adhere to the same reliability standards as the incumbent TNSP.

In the case of multiple TNSPs, a framework should be established to clearly define the roles and responsibilities of the incumbent, other TNSPs, the AER and AEMO. The basis of the relationship between the incumbent TNSP and other TNSPs would need to be described in the National Electricity Rules. The Rules framework could be supplemented by agreements between TNSPs, with recourse to arbitration if required, as to last resort arrangements.

5.3.3 Establishing national reliability standards

A consistent national framework for setting transmission reliability standards is important for supporting network reliability. Establishing a consistent national framework would ensure that all TNSPs, be it the incumbent TNSP or an alternative TNSP in providing transmission services, must adhere to the same reliability standards[16].

5.3.4 Incentive schemes for network availability

A fully contestable environment should foster the development of commercially viable availability incentive schemes. Such incentive schemes directly relate (in financial terms) the TNSP's transmission services with the performance of its network. Any network availability incentive scheme puts an explicit value on individual asset availability. The rate to be applied for an individual transmission system element should reflect the criticality of its outage and the time period in which the outage occurs. This

[16] Australian Energy Market Commission. "AEMC Response to the Competition Policy Review Issues Paper". July 2014. Available at: http://competitionpolicyreview.gov.au/files/2014/07/AEMC.pdf

incentive scheme would be applied to any parties operating the transmission services, whether third party or incumbent[17].

5.3.5 Enhancing innovation

To enhance the TNSP's ability to propose innovative solutions for the existing shared network, the incumbent TNSP could further separate their contestable and monopoly business activities. In the case of the Heywood tender, while SP AusNet had agreed to establish two separate bid teams, both teams reported to the same manager.

There is a further issue as to whether AEMO's tender processes could act to limit innovative solutions. Rather than prohibiting all contact between tenderers to protect against collusion, AEMO could establish terms on which competitive tenderers are permitted to enter into discussions with the incumbent DTSO during a competitive tender process.

To enhance contestable TNSPs' ability to propose innovative solutions would be to explicitly allow them to propose modifications to the terms set out in AEMO's tender document. If a TNSP proposes a preferable solution to the one originally proposed in the tender, this could form the basis of a further contestable process.

[17] Australian Energy Regulator. "AER submission to the Productivity Commission Inquiry into Electricity Network Regulation". April 2012. Available at: http://www.pc.gov.au/inquiries/completed/electricity/submissions/sub013-electricity.doc

6. Evidence from the Argentinian market

6.1 Market Overview and Situation Analysis

6.1.1 Overview

During the last two decades the Argentine electricity industry went through a restructuring process. It started with some reforms in 1989, which intensified in 1992-1993. As a result, this process dissolved the vertical organization of the electricity industry and privatized most companies in this sector (which included generation, transmission and distribution activities).

Total electricity generation in 2014 was 131 TWh, about 1% higher compared to 2013, according to Argentina's electricity market administration company Cammesa. In 2014, about 63.5% of the country's power generation came from thermal power plants, 31% from hydropower, 4% from nuclear power, and 2% from wind and solar. As much as 1.1% was imported from Uruguay and Paraguay. The InterAndes Transmission Line links an Argentine power station to Chile's northern electric grid. Argentina imported 18.4 billion KWh in 2014, a 79% increase from electrical energy imports in 2013 (8.0 billion KWh), to meet increasing domestic electricity demand

There are two main interconnected systems, SADI (Sistema Argentino de Interconexión, Argentine Interconnected System) in the North and center-South of the country, and SIP (Sistema de Interconexión Patagónico, Patagonian Interconnected System) in the South. Both systems have been integrated since March 2006. The electricity market in the SADI area is managed by the MEM (Mercado Eléctrico Mayorista).

6.1.2 Introduction

The transmission expansion policy introduced in Argentina in 1992 has been refined and modified since then. Refinements include provision for transmission companies and others to propose quality and substation expansions. The transmission planning process introduced was based on the Public Contest Method. This approach provided that major transmission expansions were to take place only where users proposed them and a majority voted in favour, confirming that they were prepared to pay. Financing, construction, operation and maintenance of the agreed expansions were then to be put out to competitive tender. There have been concerns about the Public Contest method. Particular criticism has been directed at the Area of Influence method that determines the allocation of costs and votes amongst transmission users.

In 1997, the government commissioned studies to extend the competitive market. These identified the Area of Influence method and the absence of transmission rights as major deficiencies. A key problem of the Area of Influence method is that it does not in fact identify beneficiaries or accurately measure users' share of benefits. In addition, the government proposed congestion rights and a new 'risk bearing expansion' method to allow a wider range of participation.

Provincial governments pressed for more regional expansions. In 1999 the government increased a surcharge on electricity to establish a Federal Transmission Fund to be allocated by the Federal Council of provincial governments. The incoming government made the Federal Transmission Plan a priority, with the objective to finance transmission expansions that the Secretary of Energy identifies as financeable. It introduced a new Open Season method for inviting private participation, and suspended the previous second round of reforms. The Golden Rule — which basically performs a formal check on the technical aspects of the projected expansion, and evaluates whether the net present value of total cost of investment, operation and maintenance costs of the system with the project is less than the net present value of operation and maintenance costs of the system without it. — did not in practice apply to such expansions. Five (later four) new regional lines were identified, that would also link the radial system into a meshed network.

The experience of Argentina must be seen against the topology of its grids and the state of development of its economy. The early reforms in Argentina took place based on a network which was (initially) almost entirely radial and there was no attempt initially to define property rights for each line. Only as the reform process progressed did the networks become increasingly meshed.

In a country with a developing economy large and timely transmission expansions are important to meet the demands of electrification and rapid economic growth. In developed countries with very low demand growth nodal pricing on the meshed transmission network may be a better way to price existing transmission capacity and may give good price signals for transmission expansion along existing pathways. In developing economies with linear transmission systems merchant transmission expansion may be successful. This is because loop flows do not complicate the allocation of benefits. Such systems are unlikely to work well in rapidly growing meshed systems.

6.1.3 Prior to Reform

Before privatisation and restructuring in 1992, transmission was provided by state-owned companies regulated by the government. The regime was characterised by excessive operating costs and capital investment, with prices held down to combat inflation. Inter alia, long and expensive transmission lines were repeatedly constructed without economic justification, and their utilisation rates were low.

Before the electricity sector was reformed, the federal government owned three electricity companies in Argentina, responsible for extra high voltage transmission (mainly 500 kV) and high voltage transmission (mainly 132kV), as well as most generation and the distribution of electricity. Most of the 23 provincial governments had their own electricity distribution company, in some cases also operated generation and in most cases operated some high voltage (132kV) transmission lines. Several hundred cooperatives throughout the country, in some cases partially owned by municipalities or large users, carried out some local distribution.

6.1.4 Restructuring and Privatization

The electricity industry was restructured and privatised in 1992. Even though the reform was similar to the UK it went further especially regarding restructuring. Transmission was restructured into an extra-high voltage 500 kV system (Transener) and seven separate high voltage systems. As part of the reform, restructured incumbent companies were made responsible for operation and maintenance of the existing transmission systems, but not for most new investment. A novel approach called the Public Contest method provided that major transmission expansions were to take place only where users proposed them and a majority voted in favour, confirming that they were prepared to pay. Financing, construction, operation and maintenance of the agreed expansions were normally to be put out to competitive tender.

Existing and new transmission lines were regulated separately and differently. Existing systems were subject to a price cap with incentives for efficient operation and maintenance. This has worked well as operating costs, number of faults, forced outages and average recovery time have all been reduced.

6.1.5 Transmission Expansion under the initial reforms

The initial regulations provided three different methods for the construction and operation of new transmission lines for public use: Contract Between Parties (expansions for one or a few users, such as connections), Minor Expansions (under $2m for Transener's system), and Public Contest. It was envisaged that the Public Contest method would be used for the most significant investments involving many parties, and this proved to be the case. In practice there were many more expansions by the other methods, even though their aggregate value was less.

In order to request an expansion of transmission capacity by Public Contest, the proponents apply to the Transmission Company that holds the concession in the area of the expansion, which reports on the technical feasibility of the request. CAMMESA carries out a technical study, using the Area of Influence method, to identify the beneficiaries of the expansion and the proportion in which each beneficiary would have to share the costs of remuneration. The proponents must represent at least 30% of the beneficiaries that the expansion would bring in its —area of influence. The regulator, ENRE has to check that the Golden Rule is met and arrange for a public hearing. In the event of opposition by 30% or more of the beneficiaries of the expansion, ENRE (the Argentinian energy regulator) must reject the expansion request. If there is no opposition, or not sufficient to warrant further investigation, ENRE must approve the request, and issue a Certificate of Convenience and Public Necessity. The proponents then arrange for a public tender to Construct, Operate and Maintain the proposed expansion. Subject to some qualifications, the tender (known as the COM contract) goes to the lowest bidder.

Initially, the request for an expansion had to be accompanied by an offer of a COM (Construction, Operation & Maintenance) contract from a transmission company or from a prospective independent transmission company, with a proposed constant annual "fee" over an amortisation period approved by ENRE. Transmission expansions via the Public Contest method are paid for by all those parties who are identified as beneficiaries in the area of influence of the expansion, in proportion to their shares as beneficiaries. This calculation is updated monthly during the amortisation period of the COM contract, so that users pay for the expansion in proportion to actual use. After the expiration of this amortisation period, the annual remuneration for operation of the additional facility follows the remuneration regime applicable to existing installations of the incumbent Transmission Company, which essentially covers operation and maintenance only.

The Argentinian transmission expansion approach is based on the following:

- Coordinated Spot Market. Organized under an Independent System Operator with Locational Marginal Pricing.
- Expansion of Transmission Capacity by Contract Between Parties. Allowed merchant transmission with voluntary participant funding.
- Minor Expansions of Transmission Capacity (<$2M). Included regulated investment with assignment of cost, either through negotiation or allocation to beneficiaries as determined by the regulator, with mandatory participant funding.

- Major Expansions of Transmission by "Public Contest" Method. Overcame market failure without overturning markets.
    - Regulator applies the —Golden Rule (the traditional Cost-Benefit Test).
    - 30%-30% Rule. At least 30% of beneficiaries must be proponents. No more than 30% of beneficiaries can be opponents.
    - Assignment of costs to beneficiaries with mandatory participant funding under —area of influence methodology.
    - Allocation of accumulated congestion rents to reduce cost of construction (Salex funds).

6.1.6 Delivery

In the case of the Public Contest method, competitive bidding is used when expansions exceed a certain size. The procedure in the case of competitive bidding consists of the following steps:

- The proponents who want a new line to be built, request authorization to do so from the transmission firm to which they are connected. The request describes the project and indicates either (i) a maximum annual fee users must pay, such that if nobody bids within the fee ceiling, the project is cancelled; or (ii) an annual toll at which the transmission firm undertakes to build the line under a build, operate and maintain (BOM) contract.
- After the project is approved in a public hearing, the requesting beneficiaries, who become the parties to the future BOM contract, call an international tender. The auction is awarded as follows:
    - If the maximum fee modality is chosen, the line is allocated to the bidder offering the lowest annual fee for 15 years, subject to a ceiling of the maximum fee. If there are no bids below the maximum fee, the auction is declared void and the process terminates;
    - If the BOM contract modality is chosen, the line is awarded to the bidder offering the lowest fee, provided this is below 85% of the amount bid in the BOM contract. If the lowest bid is above 85%, the firm that offered the BOM contract and the firm submitting the best bid have the right to improve their offers. The line is allocated to the lowest final bid. Once the line is built, the owner charges the beneficiaries the agreed fee for 15 years, after which it charges the remuneration established for the other installations.

6.1.7 Fourth Line

Soon after the new policy was implemented, a Fourth Line from the Comahue to Buenos Aires was proposed but rejected by a majority of market participants. This line was allegedly much-needed, and had been widely canvassed under the previous regime. The rejection was perceived as evidence that the Public Contest method did not and could not work. It seemed that transaction costs outweighed the advantages of cooperation between market participants.

Seven generators were due to benefit from the line in terms of energy benefits. However two of the generators were closer to Buenos Aires than the others. This meant that they were able to benefit from higher nodal prices when the line from further away from Buenos Aires was constrained. The new line would have relieved the transmission constraint facing the other 5 generators but reduced the local energy price facing the first 2 generators. Hence these two generators voted against it. They were joined by some distributors who did not want the amount of power that they bought from further away from Buenos Aires to increase. This was because they would not benefit from the reduced price of power (as this was passed through to customers) but they would face higher risk of transmission system failure and associated supply failures. The line was eventually built some 18 months later than under the initial proposal.

6.1.8 Second Package and Further Reforms

In 1997 the government commissioned studies to extend the competitive market. These identified the Area of Influence method and the absence of transmission rights as major deficiencies. The Area of influence method had been introduced for reasons of practicality. Despite its limitations, consultants to the Secretary of Energy could not identify a better method. In a 'second round of reforms' in 1998 the government left the method in place. The government also proposed congestion rights and a new 'risk bearing expansion' method to allow a wider range of participation. In addition, the regulatory arrangements were modified to allow a greater role for the transmission company, the system operator CAMMESA and the regulator ENRE in proposing and authorising expansions to improve quality and maintain reliability, and in relation to substations. Several expansions were made using this new method. Participation by distribution companies may have been hindered by lack of clarity about funding and obligations, but these ambiguities could have been resolved by provincial governments, who on occasion were deemed responsible for preventing or delaying proposed expansions. The 'second round of reforms' were rescinded before they became effective

A Federal Transmission Plan was introduced in 1999, to build lines designated by the federal and provincial governments after pressure from Provincial governments for more regional expansions. The incoming government made the Federal Transmission Plan a priority, with the objective to finance transmission expansions that the Secretary of Energy identifies as financeable. It introduced a new Open Season method for inviting private participation, and suspended the previous second round of reforms. The Golden Rule (transmission expansions should lower total costs) did not in practice apply to such expansions.

In March 2001 the impending economic crisis led to the recall of Carlos Bastos, who had introduced the original reforms. He suspended the Federal Plan and reinstated variants and extensions of the earlier market-oriented reforms. Within a few months Congress repealed these measures.

In 2003 there was a temporary process for upgrade expansions paid for to a large extent by all users. The Federal Plan was relaunched.

As of 2007, 36 proposals had been made, some with variants making a total of 40 proposed major expansions. Of these 40, 35 were accepted and all those were implemented. The four largest Public Contest expansions ranged from $25m to $247m. There were also other methods of transmission expansion, and from 1994 to the 2001 crisis the number and value of transmission investments steadily increased. Over this same period, all but 5 of the 163 transmission expansions, accounting for all but $3m of the $809m total value, were voluntarily agreed by the users.[18].

[18] Transmission Expansion in Argentina 1: the origins of policy", Energy Economics 30(4)

6.2 Customer Impact / Lessons Learned

The approach developed in the 1990s which emphasised the competitive market has been replaced by federal and provincial planning, using regional expansions to encourage growth and development of the sector. Transmission private ownership was deemed to be successful at improving technical and cost efficiency and increasing investment. However some serious regulatory issues emerged. In particular the process for approval of large transmission upgrades was controversial and the regulator was subject to political influence, which unnecessarily increased the uncertainty of the regulated revenue of network companies.

It is noteworthy that the Argentinian experience has to be viewed within the context of the relatively volatile political climate. The sector has undoubtedly been subject to major effects resulting from the macro-economic crisis and the government reaction to it.

Lastly, the Argentinian experience demonstrates that the failure to design a comprehensive reform package (that address both economic and non-economic factors) from the onsite will lead to controversy, investment uncertainty and serious regulatory issues emerged. Thus, leading to a need to regulation/market redesign and government intervention.

Key lessons learnt of interest to OFGEM's review on the impact of onshore electricity competition on customer interests are summarised below:

6.2.1 Quality of Supply

The Public Contest Mechanism has been criticised as an approach that has failed to deliver quality of supply, partly as a result of reluctance of distribution companies to participate; that the Public Contest method was deficient, that transmission rights were lacking; that there were problems in achieving consensus among the parties.

Under the Public Contest' mechanism Transmission expansion was to be determined by negotiated third party access. However, the methodology used to determine the "beneficiaries" of a new transmission line and what are the percentage levels of the benefits of the various beneficiaries seems to be based on energy usage, rather than on economic or market benefits - once new lines were built payment was to be on the basis of energy usage, those whose power went down the line would have to pay for it, independently of the costs imposed by their peak demand. Since this methodology sets the payments that the "beneficiaries" are required to make towards the costs of constructing a new line, predictably significant problems arose from the unwillingness of some parties to contribute more for new facilities than they expect to gain economic benefit from. Equally or more significant, is the danger that a proposed new line is actually not a worthwhile investment, or not the best choice of an investment, or not a well-timed investment. There is also the allied danger that a desirable public good project would be missed, because those to whom the project might bring the most benefit would be unable to pay accordingly for an assured portion of its services. It seems that some of these problems arose in the context of the issues surrounding the delayed decision to construct a "Fourth Line" which was to bring additional power to Buenos Aires from the south which we discuss above.

6.2.2 System Reliability

There have also been a number of power outages in Argentina after the privatization caused by shortage of capacity have been caused by under-investment by electricity companies in generation, transmission and distribution. The under-investment is caused by prices being too low to justify any additional investment in capacity to increase quantity or quality of supply.

6.2.3 Lack of centralized planning

The responsibilities of the Argentinian ISO – CAMMESA does not include planning. In effect, there is no single entity in Argentina whose charter includes transmission planning. An undesirable aspect of transmission system expansion/improvement in Argentina is its dependence on the willingness of transmission customers to directly bear the burden of any new investment. In Argentina it would seem sensible that one institution is charged with producing a transmission expansion plan and given some power to commission new lines. Allowing private companies alone to decide on transmission lines with important implications for the location of future economic development is unlikely to lead to socially optimal outcomes. This is illustrated in the case of the fourth line, discussed above. Even though the decision may have been marginal on economic grounds it would seem sensible to have a system which is, if anything, biased slightly towards transmission expansion, rather than against it. In suggesting this it is important to stress that the power to plan and implement transmission investments can be separated from the actual building of new lines. Incentives need to be in place to ensure that the system planner does not benefit unduly from over expansion of the transmission network and that alleged wider social benefits are evaluated systematically.

6.2.4 Investment

The 'Public Contest' mechanism of transmission system expansion was accused of being biased against investment in transmission. This was because if new lines were built initial users of the line would have to pay for it. If 30% of users objected on the basis of this charging mechanism then it would not go ahead. If the line was built under a direct contract between a transmission company and beneficiaries of the line there were other potential problems (this was the 'Contract between Parties' method). In this case as new line access rights would belong to those who paid for the line, it might be worthwhile to free-ride on the initial investment of others. This is because new users of the line might be able to pay just marginal usage costs.

6.2.5 Innovation

A very important aspect of the Argentinian case is the large number of auctions that have been held to date under the Public Contest Method. There seems to have been an evolutionary design of the tender, which aimed at maximizing the cost saving by:

- Increasing the number of bidders
- Allowing bidders to focus more on the aspects that they were more effective

This meant that the engineering specification pre-tender became more and more particular. In the Argentinian case this seems to have worked well, attracting a large number of bidders, which in some cases included engineering technology companies such as ABB and Siemens directly. The detailed level of design specification seems not to have stifled innovation but in turn enabled it by attracting technology companies, who could offer state of the art solutions.

6.2.6 Reduction in Cost

The Public Contest competitive process produced favourable results in this respect. The number of bidders was sufficient to generate significant competition, which brought about cost reductions (the cost of building a 500kV transmission line roughly halved over the first five-year period). Three quarters of the successful bids were below the minimum acceptable level specified by the parties.

Furthermore, there were adequate numbers of bidders for the expansions, ranging from 1 to 7 with median 3. Competition was effective: in over two thirds of the cases the winning bid was below the specified maximum, the incumbent won less than one fifth of the tenders, and at least nine independent competitors emerged and won tenders (as of 2008). Competition brought down by about half the costs of building and operating new lines.

6.2.7 Reputation

In November 2012 Argentina's capital, Buenos Aires, was hit by a major blackout that left more than a million homes without power and caused rush hour traffic jams. Further blackouts were experienced in January 2014 and highlighted the importance of reputation in any transmission system.

As the integrity of the system is called into question by such a failure it should be the job of the regulatory agency to ensure that all the relevant companies have the appropriate skillset, processes and expertise to avert and if necessary manage such crises and that investment levels are adequate in the long term not just for the initial project establishment.

7. Conclusions

7.1 Common Themes from Lessons Learned

While there have been specific conclusions in each country and region researched, there are also a number of common themes that we can draw out that cut across international boundaries:

1. **Timeframes** - Many countries are taking steps towards greater competition in electricity transmission, however there is very little history and experience to draw on with regard to completed projects and lessons that encompass success and failure of delivery, ongoing maintenance and ultimate impact on system reliability
2. **Whole of Life Cost/Benefit –** It is relatively easy to establish a competitive tender focused on reducing up-front costs. However international experience points to the importance of considering whole of life and net-present-cost elements to provide best protection for customers and longer term system integrity. These costs are not easy for regulators to assess however and do require a thorough cost benefit analysis, including consumer benefits that are often difficult to assess with accuracy. There is also some evidence that a tender introduces inherent bias towards a significant capital-based transmission project rather than other opex-related innovations or changes to relieve system constraints.
3. **Bidding Progression –** There is growing evidence of a progression in approach from bidders, starting with fairly simple competition based on up-front capital costs through to greater use of capped prices and caps including longer term operating and maintenance expenditure. Ultimately this provides a lesser risk that customers will face economic surprises, however may pose challenges for bidders to do this without facing undue risks themselves in the long run.
4. **Level Playing Field –** Questions commonly arise as to how best to balance the need for favourable economics and to leverage existing assets and capability vs the desire for a level playing field for all bidders. It may be reasonable for an incumbent to make effective use of their investment in easements for new transmission; what is not so reasonable is where an incumbent cross-subsidises investment between contestable and uncontestable investment to appear more competitive.
5. **Provider of Last Resort –** Global experience highlights the criticality of having a back-up plan and provider of last resort should the chosen transmission provider fail to deliver. Incumbent transmission operators will expect compensation to keep their back-up scheme alive in case the alternative plans fail to proceed as planned. There is also a risk that a significant reduction on the incumbent TO's role will make their ability to perform this "last resort" role more difficult as their capital base and network coverage erodes.
6. **Complexity of Interactions –** The increase of complexity in planning for and establishing transmission under a competitive arrangement should not be under-estimated. This has an obvious transaction cost for the regulator and SO; what is not so easy to estimate but is far higher is the broader inefficiency in planning and delivery timeframes, coordination of multiple

players and the impact of less clarity of responsibility between SO and TO, including the potential impact on reliability.

7. **Reliability Standards –** Experience from all regions studied demonstrated the importance of a consistent national framework for setting transmission reliability standards. This is a critical question for Great Britain under ITPR as the electricity system overall continues to come under pressure from renewable growth and a reduction in centralized flexible generation. It is also an area where OFTO arrangements did not need to be far reaching given the lesser consequences of lower reliability for an offshore wind generator compared to onshore transmission.
8. **Difficulty of Democracy –** As much as allowing key customers to decide which projects should proceed sounds a worthy goal, as witnessed in Argentina this democratic approach is fraught with difficulty given the various vested interests of all market participants. A truly independent judgement that is transparent and auditable while recognizing the importance of customer outcomes is a preferable approach.

7.2 Other Conclusions

Other conclusions reached through our research are as follows:

a. **Capital Cost Reduction** - There is evidence that initial capital costs can be reduced through competition, although as noted above many of the competitive tenders are yet to proceed through delivery phase to enable true longer term success and real whole-of-life costs to be evaluated

b. **Due Diligence** - Thorough due diligence at the time of the tender is critically important including clarity on the consequences for failure to deliver at later stages throughout the lifetime of the contract. This is particularly complex in a "Go Early" model where evaluation includes a variety of approaches to the project as well as different commercial models and costs. Evidence from PJM in particular demonstrates that this analytical complexity can easily get out of control.

c. **Initial Arrangements** - There is a premium on getting the initial arrangements right, recognizing that what is optimal may differ depending on market structure, regulation, organizational incentives and the desired outcomes.

d. **Reputation –** Given the critical nature of electricity transmission infrastructure the reputation of whoever builds and owns it is of vital importance. In the short term this includes questions of assuming liability and credit worthiness if projects progress differently to initial expectations, however longer term the need for a commitment to consistent reliability and public trust in CATOs cannot be ignored either.

e. **Innovation –** There is evidence of innovative solutions and construction techniques being adopted in some tenders, such as the winning bid for Artificial Island included directional boring to control costs and manage environmental risks when crossing the Delaware River. Where evidence is not so clear yet is whether the added risks of some innovations bore fruit overall or whether a "tried and true" approach would have been a better option in hindsight.

f. **Increased role for the Regulator –** Introduction of competition in transmission results in a bigger and essential role for the regulator. This includes an increase in scope for price controls, oversight of tender management, monitoring, addressing conflict of interest concerns and SO/TO code development. This will place potentially major demands on the regulator, including in respect of having adequate levels of expert resource.

7.3 Conclusions by Customer Interest area

Customer Interest Area	Conclusions
Promoting efficiency and economy on the part of the licensee	• Some evidence exists that planning and build timeframes will push out under competitive tendering, especially with the complexity of "go early" schemes. • This may well be offset by cost efficiencies and benefits from an increase in innovative approaches to transmission build and operation. • The impact on incentive arrangements for the System Operator will require close attention by OFGEM.
The security of supply of electricity (and gas) to consumers	• Risks of system security impact from Argentina however little elsewhere as yet • System reliability will require clear national standards and is likely to become more complex to understand and maintain
The reduction of greenhouse gases	• Competition can promote the reduction of greenhouse gases in the initial design if the assessment framework rewards such initiative. • International experience suggests that during the life of the asset there is little or no incentive to innovate to meet climate change goals
Protecting the public from dangers	• Reputation of bidders and owners in the long term is an issue of importance • A focus on consistent reporting and management of faults and customer interruptions is vital to ensure safety and assurance of network performance
Secure diverse and reliable long term energy supply	• Little evidence that diversity of supply is negatively impacted; positive outcomes may well occur from greater competition in transmission improving feasibility of further supply options • Effective management of system reliability may become more challenging with a large number of CATOs

7.4 Specific Out-takes for National Grid

While there are a number of overall conclusions, specific areas we would highlight that are of particular relevance for National Grid's position are:

a) The reality that it is still relatively "early days" in the development of competition in transmission requires caution on hard and fast conclusions related to success. While there is evidence of up-front capital cost savings many of the competitive tenders are yet to proceed through delivery phase to enable true longer term success to be properly assessed.

b) The definition of "success" in establishing initial arrangements and performance standards is important. This should include the wider set of customer interests that go well beyond simple cost economics and a more holistic approach to network performance that addresses reliability, whole-of-life benefits and wider system interests that require asset owners and managers to maintain a sound reputation and contribute constructively to the overall integrity of the grid.

c) OFGEM have a duty to current and future customers with a range of customer interest areas as noted above. Even if there are short term cost savings the longer term benefits for future customers are not clear. The wider ramifications of ITPR in terms of customer impact also go beyond transmission competition given the considerable System Operator impacts and potential in theory to extend this approach to lower voltage networks as well if it is deemed a success.

d) National Grid's role as the Provider of Last Resort needs to be clearly set out along with fair expectations for compensation and how this is managed in the overall system planning. National Grid's ability to perform this ongoing role should also be highlighted as it should not be taken for granted.

e) Even though it is an incumbent, National Grid can act now to adopt an innovative approach to new transmission to enable it to win new competitive tenders and present a fresh approach to the regulator and the market. This may be through new partnerships or an independent review of its technical and commercial approach to transmission costs and tenders.

f) Costs and complexity vary depending on the approach selected, however if more rigorous initial arrangements are sought then significant up-front costs are likely both in the detailed design of ITPR arrangements and the role for the System Operator and Regulator in early tender rounds. As a regulated and listed entity National Grid should at least expect reasonable compensation for this establishment and higher ongoing cost, let alone any additional equity risk premium that may impact its WACC.

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