Imperial College London

UNIVERSITY OF CAMBRIDGE | Electricity Policy Research Group

Final Report

Integrated Transmission Planning and Regulation Project: Review of System Planning and Delivery

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Material presented at the two workshops is available at:

http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=1&refer=Networks/Trans/ElecTransPolicy/itpr/workshops)

http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=9&refer=Networks/Trans/ElecTransPolicy/itpr/workshops)

Important Note

The views expressed in this report are solely those of the authors, and do not reflect the views of Ofgem or any other organization.

1. PROJECT SCOPE AND OBJECTIVES

In its Integrated Transmission Planning and Regulation (ITPR) project Ofgem wishes to know what is needed with respect to system planning to deliver the future integrated transmission system onshore, offshore and cross-border, and how the relevant institutions and the incentives around them should evolve to support this new activity. The ITPR project also considers how the onshore, offshore and interconnector regulatory regimes interact to deliver multi-purpose transmission projects[1] (MPPs) that could be a feature of the future unbundled and liberalised energy system. As part of this, Ofgem seeks to ensure that the regimes continue to provide effective and stable frameworks for the significant investment in transmission infrastructure that is required in the future.

The overarching objective guiding electricity system planning is to deliver and support an efficient electricity supply industry (ESI) that can provide secure, reliable and sustainable electricity (where sustainable means meeting environmental and climate change targets). In practical terms this means that choices in transmission and generation (T&G) should minimise the Expected Net Present Value of the total system cost subject to security, reliability and environmental standards or targets. In addition, it is desirable that the institutional design can support competition where appropriate, stimulate innovation, ensure adequate flexibility in the face of uncertainty, ensure robustness in the face of possibly changing external circumstances (to the extent this is not quite the same issue as security and reliability) and provide credibility and assurance to private investors so as to reduce their cost of capital and be able to finance the construction of both transmission and generation assets at least cost.

In Great Britain it is projected that an unprecedented amount of transmission investment will take place in the coming years. Indicatively, these investments will be the largest transmission network reinforcements since post WW II expansion. In Table 1 the projected range of onshore, offshore and cross-border investments to 2030 is presented against the estimated asset values:

Table 1: Current and projected transmission RAV[2] (£bn)

	Estimated asset value (£bn)	Expected Investment (£bn)
Onshore	**8.4**	**6.2 – 12.4**
Offshore	**2.5**	**8 – 20**
Interconnection	**2**	**8 - 20**

As Table 1 indicates, not only is there expected to be an exceptionally large transmission investment program over the next decade but there is also significant uncertainty with the amount, location and timing of new generation connection, which imposes significant uncertainty in

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[1] *Multiple purpose projects could serve the combined purpose of connecting offshore generation, providing reinforcement of the onshore network and/or linking our market with that of other Member States*

[2] *The expected investment ranges have been established by considering minimum and maximum investment scenarios from a number of sources. These include the RIIO-T1 final proposals (available at: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/Pages/RIIO-T1.aspx), the National Grid Electricity Ten Year Statement and Imperial College analysis (Imperial College and NERA Consulting, 2012, Understanding the Balancing Challenge, Analysis commissioned by DECC, available at: http://www.nera.com/nera-files/PUB_DECC_0812.pdf)*

relation to the overall scale of transmission network investment. Consequently, the key questions that this project aims to answer are:

- *Planning:* Will the current arrangements deliver an optimum level of transmission that will maximise the GB social welfare? And
- *Delivery:* Will this investment be undertaken in an efficient manner and delivered at minimum cost?
- *Options:* If not, what are the options for improvement of the present regimes?

Our approach to addressing these questions involved:

- Conducting an in-depth review of the existing GB arrangements across the three regimes identifying the key strength and weaknesses, considered in the context of the EU target model
- Undertaking a comprehensive review of the principles of transmission planning and delivery and assessment of strengths and weaknesses of international regimes, including the United States' Standard Market Design Model (through an international workshop with leading academics and practitioners);
- Capturing and analysing experiences and lessons in other sectors associated with planning and delivery (involving railway, airport and telecommunication sectors); and
- Holding bilateral stakeholder consultations and workshop.

The key outputs of the analysis undertaken are that we have:

- Identified key areas of concerns associated with the present regimes that are discussed in Section 2. These are:
    - *A mis-aligned incentives framework for transmission investment and operation*: the current incentives on TOs, the NETSO and other network users, especially in the case of the onshore network, are likely to lead to inefficient transmission planning and delivery
    - *A lack of coordination of operation and investment:* current arrangements lead to inefficiencies in interaction between TOs; inefficiencies in interaction between regimes; lack of coordination across regimes and difficulty in the development of Multiple Purpose Projects; inefficiencies of investment at the regional level due to lack of coordination; and lack of coordination over time considering current and future network users.
    - *The presence of substantial conflicts of interest:* or the perception of those, have been identified at a number of levels. These include conflicts arising from the competitive businesses of the NGET, conflicts due to preferential access to information as well as EMR contract design and transmission planning conflicts. Their existence necessarily alters the incentives of different parties engaged in transmission planning and delivery leading to potential inefficiencies as well as complicating the role of Ofgem and its ability to implement incentive schemes.
- Proposed three key options for future evaluation of GB transmission regimes, presented in Section 3. The three developed options, cover the full spectrum of institutional

arrangements with respect to transmission planning and delivery and any alternatives would in effect be a subset. For each option we present: key characteristics; evolution of the current regimes; the ability of the option to address the concerns; ability to facilitate regional integration; and key strengths and weaknesses. The identified options are:

  - *Improved Status Quo Option*: this option preserves the current regimes while addressing the identified concerns by establishing a shadow Independent Design Authority (IDA), which would scrutinise and challenge Transmission Owners' plans and co-ordinate planning across regimes
  - *TSO Option:* the TSO option would deliver benefits of significant synergies with respect to operation and ownership as well as planning, designing and delivering the transmission projects. However, there are a number of pre-requisites including forming a GB TSO and the implementation of an efficient short term and long term transmission pricing regime supported by optimum Performance Based Regulation.
  - *ISO Option*: an Independent System Operator (ISO) would operate the transmission system across all regimes, would plan and coordinate the investment and facilitate delivery of investment through competitive tenders. The ISO would also be responsible for delivering the EMR provisions.

- Summarised the main advantages and disadvantages of these three options in Section 4:
  - *Improved Status Quo Option*: this option could be introduced relatively easily but does the least to overcome the problems identified.
  - *TSO Option:* this option has the potential for the greatest efficiency, subject to the extremely challenging task of introducing adequate performance based regulation. It would involve significant asset transfers between companies and it is very unlikely that it could be introduced in the short term
  - *ISO Option*: the changes required by this option would be much easier to implement than those with the TSO, and it would go further to mitigate the problems we have identified than the Improved Status Quo Option

We recommend that an impact assessment be carried out for both the Improved Status Quo Option and the ISO Option. The Improved Status Quo Option could be seen as an interim solution that might be by-passed if it is assessed as being of little benefit, but could be worthwhile during preparations for implementing the ISO Option. We see the latter as the most likely enduring solution unless there is willingness to reform the market and send efficient locational signals.

2. CURRENT REGIME CONCERNS

In an unbundled and liberalised market coordinated, central planning of both generation and transmission is no longer an option, and instead independent market participants (TOs and generators) require price signals and/or contractual arrangements if their decisions are to be collectively efficient. Based on our analysis of the current regimes' strengths and weaknesses presented in Appendix B, the extensive literature review on international experience conducted (Appendices C and D) and the inputs received from the International Workshop, we have identified that the overarching weaknesses of the current GB transmission arrangements stem mainly from the lack of efficient transmission access pricing[3]. We note that market reform is outside the scope of the ITPR project, and that Energy Market Review assumes no major changes in this area. Given this, we have identified mitigation measures that Ofgem/DECC could develop in order to enhance the efficiency of transmission network planning and delivery whilst retaining the existing market design and approach to access pricing[4]

Given the absence of efficient market design, the three key areas of concern identified above need to be addressed. We look at each in turn:

- A mis-aligned incentives framework for transmission investment and operation (Section 2.1)
- Lack of coordination of investment and operation (Section 2.2)
- Conflicts of interest (Section 2.3).

2.1 A MIS-ALIGNED INCENTIVES FRAMEWORK FOR TRANSMISSION INVESTMENT AND OPERATION

The onshore system planning process in GB is largely based on the following key principles:

- TOs develop investment plans based on generators' / grid users' commitments (indicating proposed connection requirements) and anticipated future needs based on industry-developed future scenarios; and
- Major onshore network investment during the price control period is facilitated through the Strategic Wider Works scheme.

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. 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. Similarly, new interconnection assets are market-driven (whether merchant or regulated) and interconnection developers are incentivised to ensure that design, delivery and operation are efficient, although their location is subject to distortions, given that TNUoS charges do not apply to interconnectors. However, the scope of innovation and technology development in offshore

[3] *In Appendix A we stress the key role that the short term locational marginal pricing (Standard Market Design Model), combined with transmission tariffs based on the beneficiary pays principle, have in facilitating efficient transmission operation and investment.*

[4] *In this context, it is important to recognise that the GB transmission arrangements and in particular the interconnection and offshore regimes are significantly more market driven than those found elsewhere in Europe.*

networks is very significant and this will be very relevant for the development of future more complex network topologies (discussed in the coordination section, 2.2).

In the case of the onshore network, given the current transmission tariffs with the majority of network costs socialised, and the fact that all balancing costs are socialised, users are not sufficiently incentivised to constructively engage in the transmission planning and operation process to drive efficiency. This implies that the efficiency of the transmission planning and delivery process in GB largely depends on the TOs' incentives under RIIO, the NETSO incentives and the ability of Ofgem/DECC to scrutinise the proposed investment plans.

TO Incentives

The majority of NGET and Scottish TOs' revenue is RAV-based. Historically there has been a tendency (supported by the RAV based approach) to favour capital investment. Despite improvements to the regulatory approach in recent times the RAV based approach may continue to encourage capital expenditure. Thus although menu regulation does incentivise efficient building once investment programmes have been agreed (or in the case of Strategic Wider Works triggered during the price control), the efficiency of asset planning will largely depend on the ability of the regulator, as the service buyer, to ex-ante evaluate and benchmark investment costs prior to the price control period. It is unclear what ex ante incentive TOs have to propose non-asset heavy solutions where these are likely to receive regulatory approval.

If RIIO works well the main impact of any remaining incentive problems will be for informational rent transfer to the TOs, and not necessarily inefficient delivery, which is some consolation. However, RIIO has just been implemented and it will be some time before its full effect can be assessed.

Furthermore, lack of fully efficient pricing (and absence of beneficiary pay principle) inherently leads to sub-optimal generation siting decisions, which may be aligned with the commercial interests of the incumbent TOs. At the same time, socialisation of balancing mechanism costs and lack of short term access pricing results in inefficient operation and increased network constraint costs potentially create opportunities for gaming. In 2008/2009 it was estimated that over 50% (£125mn[2]) of the observed congestion costs were due to market power abuses. Inefficient dispatch and countertrading, which would be mitigated by locational spot pricing, encourages transmission over-investment as an indirect method of reducing countertrading balancing mechanism costs. There is the suspicion that this enhances the ex-ante case for increased allowances for transmission investment before each price control period, to the benefit of the commercial interests of TOs.

Indicatively, as analysed by NERA and Imperial College [1] moving from the current charging methodology to a uniform transmission tariff (i.e. moving further away from optimal locational charging), would result to an increase in consumer's costs between 2011 and 2030 of £20.2 billion in real terms. This is due to the increase in prices in the wholesale power market caused by the increased cost of new entry, increased transmission losses, increased transmission investment and generation operating costs. This analysis does not imply that the current charging methodology is appropriate but rather the importance of an efficient transmission tariff with cost reflective locational signals.

SO Incentives

On an operational level, the 2013-15 SO incentives scheme [3] will be a target based incentive scheme broadly similar to the 2011-13 scheme, which is currently in place. It will also include some additional incentives, which would focus on specific outputs delivered by the SO (details of these incentives are currently being developed through consultation). Exposure to SO incentive mechanism has delivered reduction in network constraint costs, some of which involved introduction of live line maintenance of high voltage overhead lines, introduction of temporary line facilities and adoption of flexible/re-locatable voltage support equipment aimed at reducing constraint exposures, introduction of new conductor systems with a range of capability/capital cost/lifetime cost trade-offs etc.

The extent to which NGET will co-optimise transmission investment and operation will depend on the weight that the TO and NETSO incentives have on its total revenues / profits.

Indicatively, as displayed in Figure 1, National Grid's RAV-linked profit from electricity transmission was £849mn against £9mn from the NETSO operations in 2011/12.

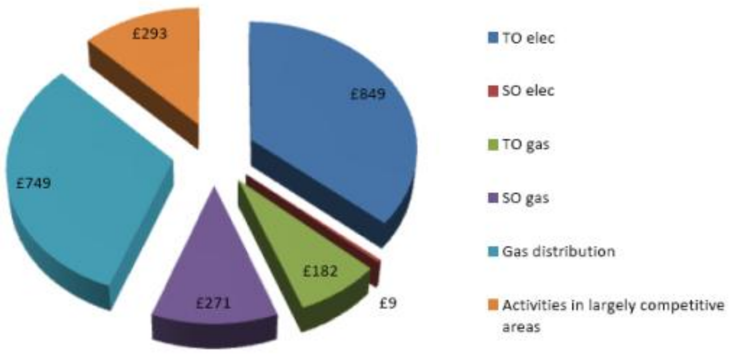

Figure 1: National Grid 2011/2012 profit (£mn)

Given the very low contribution of the SO activities to its overall revenue and profits, the impact of its incentives may be on maximising benefits to the TO business rather than on co-optimising transmission planning and operation.

Absence of incentives for implementation of efficient operational measures

Given that beneficiaries of wider network reinforcements are not directly exposed to the cost of these reinforcements and their access to the energy market is partially subsidised by other network users, there are no strong incentives among market participants to scrutinise the TSO plans and propose more efficient alternative operational measures to network reinforcements.

In fact the incentives are perverse and lead to further degradation of efficiency of operation and investment in transmission network as the present connect-and-manage approach and non-locational BSUoS allocation directly dis-incentivises participants to offer cost-effective operational solutions that would lead to enhanced utilisation of the existing network assets. This is further exacerbated by treating inter-tripping schemes as commercial services in a market, which does not provide a cost-effective location signal. It is clearly irrational that generators in export-constrained areas price very highly the services that enhance their ability to export power. Given the present market design, constraining generation in exporting areas is in fact more profitable than fully-unconstrained exports, and this in the long run leads to overinvestment in network assets, that are not funded by the generators in exported areas. These inefficiencies are completely eliminated in markets that recognise location. Evidently, effective mitigation measures are needed to resolve this problem given that changes in market design are not envisaged in the short and medium term (this is discussed under the ISO option in section 3.3).

Clearly, a key requirement for delivering the 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. As indicated, the present incentives regime is perverse and potentially discourages network operators and market participants from actively considering potential cost-effective corrective control based operational measures.

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. Very significant advances [37]-[47], at the international level, have been made in developing and implementing a range of new effective operation and control techniques and technologies, and it is critically important that these are fully considered, as an alternative to network reinforcement, in order to ensure efficiency of the unprecedented network investment that GB is facing.

Given the absence of the market that would facilitate this, specific mitigation measures are needed to remove the bias towards investment over operational alternatives, in order to prevent the implementation of technically effective and economically efficient 'non-network' solutions as an alternative to the conventional network asset-based solutions. It is important to recognise that the present incentive regimes directly contradict the Smart Grid concept. That concept involves a shift from providing network security by redundancy in assets and a set of preventive control measures (i.e. out-of-merit dispatch), to delivery of security by implementing more sophisticated system management through opening opportunities for demand side response, flexible generation and advanced real time network control techniques. These are options that contribute to the release of additional network capacity from existing assets as an economic alternative to the straightforward increasing of capacity via reinforcement (i.e. replication) of network infrastructure.

Furthermore, the present network regulation does not consider and is unable to deal with the fundamental question of whether the level of network capacity released to network users in an operational time scale is delivering good value for money to network users. There are no mechanisms that provide assurances to all parties (network users, network operators and the regulator) that an appropriate balance is being struck between costs and benefits in the decision making process associated with the release of network capacity in real time and the provision of additional infrastructure. Establishing the optimal level of network capacity that should be made available by network operators in real time should balance (i) the value that users attribute to the level of network capacity released, against (ii) the cost of reserves, losses and expected costs of interruptions (caused by forced outages of generation and network facilities) that is associated with the volume of network capacity released. The optimal level of network capacity that should be released to users corresponds to the equilibrium when the marginal value to users of the network access equals the marginal costs associated with its provision. This equilibrium position is different across different system boundaries and will depend on the network characteristics. It changes with weather and system condition. The present network standards, developed in early 1950s are demonstrated to be very inefficient [4] and should not form the basis for the development of 21st century transmission networks.

This is in contrast with the clear trends, observed in a number of jurisdictions (particularly in South America, Australia and New Zealand), of modernising network operation and design standards [48]-[51] accompanied by rapidly growing use of advances in various technologies that can release latent network capacity through more sophisticated system operation. These include the application of coordinated special protection schemes [37]-[44], coordinated corrective power flow and voltage control techniques supported by wide area monitoring [45]-[47], advanced protection and control systems, and advanced decision making tools. All these technologies have the potential to increase utilisation of the existing network and future networks, leading to increases in the efficiency of investment. International experiences with the application of these technologies are presented in greater detail in Appendix F.

Although some of these methods (see Appendix B) are applied by the NETSO and the TOs are engaged with the Smart Grid agenda (advanced schemes in Humber Smart Zone and SSE/SHETL Registered Power Zone), the present framework is potentially a barrier to taking full advantage of such techniques given the absence of incentives for network asset and alternative non-network asset based solutions to be compared on an equal footing. The RIIO innovation incentives can play a very positive role in this, but the general assessment of the RIIO-T1 TO business plans is that capacity enhancing solutions were mainly based on asset reinforcements and not the application of Smart Grid technologies.

Ofgem's Role

Under the current incentives scheme, Ofgem (and to an extent DECC) has evolved into a sole 'buyer' of transmission service, both on and offshore. For example, in role that the regulator has for approving "Strategic Wider Works" projects brought forward under the TOs RIIO business plans. Regarding the on-shore transmission network operation, Ofgem has recognised the difficulty [3] in defining efficient long term SO incentive scheme, as this requires an in-depth understanding of transmission operation and options for managing the corresponding costs. Furthermore, this would require that Ofgem closely monitors and scrutinises planning and delivery as well as the operation of the transmission system. Again, this necessitates a progressively in-depth understanding of transmission planning, extensive cost benchmarking and importantly, but increasingly more difficult to achieve, full appreciation of the investment trade-offs between operational measures, smart grid technologies and various asset types.

Going forward, given the absence of efficient market framework, it is questionable whether Ofgem (or DECC) possess the needed expertise to increasingly act as the single buyer of onshore and offshore network services, as the complexity and interactions between these will significantly increase. Given the unprecedented level of transmission investment that is expected to take place, will increase the risks associated with the decision making process, particularly as uncertainty in timing, location and volume of this investment will be significant.

2.2 LACK OF CO-ORDINATION

Regarding the co-ordination in transmission activities, a number of concerns have been identified:

- **TO/NETSO co-ordination**: the lack of co-ordination between TOs leading to an increase in network constraint costs in the short term and inefficient investment in long term.
- **Co-ordination across regimes:** concerns regarding the ability of multiple parties (onshore and offshore TOs, interconnectors, developers of offshore generation and multiple purpose project developers) to coordinate and deliver efficient investment for GB.
- **Regional coordination of network investment:** concerns that parties delivering cross-border investment do not take into account regional network needs.
- **Coordination over time:** limited scope for anticipatory investment and absence of a formal framework to meet existing and future users' needs.

TO/NETSO co-ordination

NGET owns the transmission assets in England and Wales and is the NETSO for the two Scottish grids (and the offshore grid). Given that the NETSO is incentivised to minimise congestion costs, there is an incentive to cooperate with the Scottish TOs and coordinate maintenance. On the other hand, Scottish TOs are not strongly incentivised to cooperate (while the NETSO is not incentivised to try out solutions which would undermine NGET's business model in England and Wales). It is important to note that generators in Scotland benefit from firm access to the GB-wide market and are not affected by these inefficiencies. To some degree the newly developed Network Access Policy (NAP) should contribute to better TO/NETSO interaction and cooperation in both short-term and long-term network planning.

On the other hand if the network access regime were location specific (for example in the case that the Cheviot Boundary separated the GB market into 2 zones), the export constraint would lead to a fall in electricity prices in Scotland below those in England, which would clearly affect the revenues of generators in Scotland. This would create pressure on all TOs to coordinate their maintenance and construction outages and consider alternative operational measures to minimise the impact of constraints. In the absence of the market signals, additional mitigation measures would need to be considered in order to achieve coordination in short-term and long-term.

In the particular case of England and Wales, where National Grid acts as both NETSO and TO there is evidence of benefits from coordination of short term network operation and long-term asset management activities. On the other hand NGET has experienced difficulties in codifying reasonable performance/risk trade-offs in the SO TO Code (Scottish TOs initially unwilling to provide cyclic / short-term asset ratings). The materiality of reducing system operator effectiveness by reducing information exchanges with asset managers may approach £50m/yr, which may increase further as wind penetration and other 'connect and manage' impacts grow.

Coordination In Meeting Existing and Future Users' Needs

In order to facilitate transmission investment co-ordination across regimes and/or take into account future investment needs it might be necessary that TOs engage in anticipatory investments. Anticipatory investments refer to network developments for which full firm user commitment is not obtained at a particular point in time. However, anticipatory transmission investment may be efficient when there are material economies of scale in transmission investment, constraints associated with establishing new transmission corridors or developing new rights-of-way, or environmental constraints associated with the number of shore landing points that may be needed to connect offshore and onshore network assets;

On the other hand, given the significant uncertainty and the difficulties in predicting the time, location and volumes of new generation, the risk of investing in stranded assets could be high. These views were also reflected by Ofgem [5] in summarising the conclusions of the Offshore Transmission Co-ordination Project (OTCP): "OTCP identified that, in some areas, a coordinated approach to the future development of offshore transmission assets may be economically beneficial. Analysis carried out by Redpoint Energy, taken across four different offshore generation deployment scenarios, suggests coordination has the potential to deliver savings of around 8-15% (£0.5-3.5 billion) when compared to a radial configuration. However, the analysis highlighted the risks of a coordinated approach leading to potential asset stranding. It also found that savings from coordination are highly reliant on the scale of offshore generation deployment and the emergence of new higher-capacity High Voltage Direct Current (HVDC) technologies, both of which are uncertain."

The increasing uncertainty about future transmission needs coupled with the irreversible nature of transmission investment indicates that attractive opportunities should not be identified solely on the basis of net benefit, but also on the option value that they provide. The concept of option value is a well-established notion in welfare economics referring to the value placed on the ability to utilise an asset in the future and is recognised as an important element of the total economic value of a project. However, it is often ignored due to the inability to charge potential users who value the option of use in the future.

In the case of transmission investment, the features that give rise to significant option value are primarily the exploitable scale economies and the environmental constraints for establishing new right-of-ways. The option value concept is also applicable when evaluating the adoption of 'interim' asset-light solutions, such as the installation of a flow control device. The benefit of such solutions lies not only in the provided service (increased transfer, security etc.) but also in how they can facilitate and de-risk subsequent decisions. Given the large scale of upcoming transmission investment as well as the extended scope for synergy and strategic coordination, the formal consideration of option value in the planning process becomes increasingly important.

This necessitates that the transmission planning process and the planner will need to take a view and balance the needs of the current and future consumers and the risk of stranded assets. Practically, dealing with increased level of uncertainty in future developments, particularly with volumes, timing and location of renewable generation connections, it would be beneficial to understand the option value of alternative transmission investment propositions. In this context, the development of minimum regret analysis, presented for the first time by National Grid in the Electricity Ten Year statement is an important development. However, in this particular example, the amount of information provided is not sufficient to understand if the needs of current and future users are effectively balanced. Furthermore, the publication and dissemination of the Electricity Scenario Illustrator model (ELSI) by National Grid, that allows market participants to analyse benefits and costs of transmission investment, is a major milestone towards transparency in demonstrating the need for/benefits of alternative network investment propositions against different generation and demand backgrounds.

Co-ordination across regimes

Given the three distinct regimes and the limited amount of offshore and interconnection assets at present, there is currently little interaction between the regimes with respect to co-ordinated transmission planning, delivery and operation. Since the current net effect of radial offshore and interconnection assets on the onshore system is similar to generation and demand the main co-ordination channel is through the transmission tariffs. In the particular case of interconnection planning, the removal of TNUoS charges and the ad-hoc process for planning and connections offers is likely to lead to inefficiencies.

Furthermore, there has been a significant interest in transmission projects that cut across regimes (multi-purpose projects). Examples include offshore wind farms connecting to interconnectors and the development of meshed offshore grids that would also potentially increase onshore boundary capacities. It is expected that the volume of multi-purpose projects will significantly grow in future. Given the absence of efficient pricing signals, the current arrangements are likely to lead to inefficient design of multi-purpose projects, even if the considerable legal and licencing issues are resolved.

It is important to bear in mind that the boundaries and the definitions of the three regimes (onshore, offshore and cross-border) are artificial, given that the role of underlying assets used in each regime and across the regime is essentially the same. However, the differences and inconsistencies of the three regimes have significant implications for both the respective asset owners and network users. Several key areas of inconsistencies are identified:

(1) Capacity allocation: cross border capacity is allocated on the basis of energy price arbitrage value, implying that cost of accessing interconnectors will be market-driven. On the other hand onshore and offshore network capacity allocation is cost based (although not necessarily cost reflective) i.e. users pay network charges that are driven by network cost, rather than value- or market-driven. This presents inconsistency as an offshore generator considering connection to an interconnector would be required to pay the market price for access, while connection to offshore network would be cost based. Furthermore, whereas onshore grid access is firm (i.e. in case of network unavailability users are compensated), this is not so offshore as generators affected by offshore network failures are not compensated (though the offshore transmission companies do face non-delivery penalties). Furthermore, the firmness of the transmission rights depends on the commercial terms and conditions for each interconnector. For example IFA transmission rights are non-firm whereas BritNed transmission rights are 100% firm. This would lead to discrimination especially if offshore assets become an extension of the onshore system. With respect to multi-purpose projects this presents inconsistency in firmness, as an offshore generator considering connection to a bootstrap would enjoy firm access, while connecting to offshore system would be non-firm.

(2) Investment cost recovery and charging**:** an extension of the network capacity allocation question is the approach to charging. Interconnectors currently do not pay transmission charges and their costs are currently recovered through price arbitrage or sales of transmission rights. Offshore and onshore assets cost recovery is regulated and funded through TNUoS but the implied asset lifetime is different. This creates inconsistency and is potentially discriminatory as an offshore generator connected to an interconnector would not pay onshore TNUoS charges while connection through an offshore network would lead to exposure to TNUoS charges.

(3) Risk allocation**:** the above inconsistencies across regimes affect how risks are allocated among network users, transmission owners and consumers and as such might affect the choice of connecting to different regimes, which transmission investments are funded and how these assets are utilised. This is potentially discriminatory since offshore, onshore and cross-border assets "compete" to connect different types of generation and as such would need to be evaluated in a consistent manner.

(4) Business model: The above differences are also reflected in the business model of each regime and in particular whether developers earn regulated or merchant revenue. Onshore regime is fully regulated model with incentives for efficient planning, operation and delivery established through regulatory oversight. In the case of Offshore, whether it is generator or OFTO built, this is developer led and ultimately paid by the beneficiaries, the offshore wind generators. Nonetheless, the OFTO revenue is regulated and guaranteed by the UK consumer. This implies that there are strong incentives for efficient planning and delivery but at the same time low financing costs due to the inherent revenue guarantee by end consumers. Regarding the interconnection regime, this is merchant although it is envisaged that a cap and floor on the revenue that owners earn may be introduced. The level of cap and floor will in effect determine whether a project is classified as merchant or regulated. In case that floor for revenue is set significantly below the cost of debt of the project then equity investors in effect take significant merchant risk given that the revenue will

depend on the cross-border price arbitrage. In this case, the driver for establishing the cap&floor is to satisfy EU regulations regarding interconnections and at the same time cover some of the compliance costs that developers face. The role of Ofgem (or any party mandate with reviewing cross-border projects) would be to confirm that the welfare benefits of the interconnector are higher than its costs and establish an appropriate floor that minimises consumer exposure but satisfies EU regulation. On the other hand, **w**hen the cap&floor levels are very close to each other, this would imply that project sponsors will earn an almost fixed IRR for the lifetime of the project, and this regime would be close to regulated. There could still be some exposure to the cross-border price differentials but this would serve more as an incentive for efficient operation and maintenance. In this case, cross border development could be either developer led or centrally planned. In both cases, in effect, a central body would need to take a view on the optimum interconnection capacity and mandate or authorise proposed projects. The delivery of cross-border projects could be auctioned, similar to the present offshore regime. The different business models across the three regimes are to a certain degree justified given the different constraints and pricing arrangements under which each regime operates. However, as MPP projects are developed and the boundaries between the regimes are distorted it is likely that these differences might prevent the optimum development of an integrated network.

These inconsistencies and differences among the regimes will significantly affect the incentives of different parties to propose and undertake MPP projects. For example, NGET might not have incentives to consider MPPs that might alleviate the need for onshore investments if these are not included in its RAV. Similarly, an interconnector might discourage an offshore generator from connecting if this means that it would need to operate under the OFTO regime and potentially earn a lower rate of return. If efficient co-ordination across regimes is to be realised then these issues would need to be effectively resolved.

We stress that the inconsistencies among the regimes are driven by the differences in the setups of these regimes, although the underlying assets perform the same function. This means that these inconsistencies will not be effectively resolved unless there is a radical re-definition of the regimes or efficient transmission pricing is implemented, the latter is beyond the scope ITPR. We also note that inconsistencies in network access between national and cross-border regimes are embedded within the EU target model too. Within GB, some mitigation measures may be established, such as re-instating some form of interconnection TNUoS, but it will fall short of addressing the inconsistencies with respect to capacity allocation and firmness of access. As mentioned, efficient network pricing, would resolve these issues by facilitating the co-existence of merchant and regulatory investments [36].

Regional coordination of network investment

Cross-border transmission investment is essential in facilitating regional co-ordination and the aspirations of the EU Target Model and climate change policy. In particular, cross-border investment will need to be done in a co-ordinated market with regional partners so as to:

- promote integration of EU energy and balancing markets;
- enable generation outside GB to participate in the GB capacity market so as to minimize the cost of security of supply ; and
- facilitate efficient implementation of EU Renewables directive.

Under the current interconnection regime multiple parties are responsible for planning and delivering on a merchant basis cross-border assets with limited scope for taking into account the regional needs.

2.3 CONFLICTS OF INTEREST

Conflicts of interest are more likely to be a problem when the incentives on the party to act in its own interest, where this diverges from the public interest, are high and the probability of detection is low [52]. If both of these are true, then mitigation can take the form of aligning incentives so that private and public interest coincide, and/or taking steps to raise the probability of detection. This section examines at a rather abstract level areas in which the potential incentives on NG might occur. It does not attempt to provide evidence on the materiality of these potential incentives, which would require a separate study.

There are three potential sources of conflicts of interest in transmission planning and delivery across the regimes:

- conflicts involving businesses with competitive interest and transmission planning roles ,
- conflicts arising from preferential access to information for some parties, and
- EMR contract design and transmission planning conflicts.

Of these potentially the most serious is the first, which also could provide a motive for exploiting informational advantages and also bias system operation (particularly managing constraint costs and scheduling maintenance to benefit subsidiary businesses).

Competitive businesses

National Grid (NG) has interests in two current interconnectors (IFA and BritNed), at least one proposed interconnector (NEMO), and a possible future link to Norway. As such it is in competition with other proposed and competitive interconnectors, particularly one through the Channel Tunnel. Also, NG has an interest in the Energy Bridge MPP project looking to connect wind farms in Ireland to the GB system.

The potential conflicts arise in that NG as planner could favour investments that facilitate transmission connections to the on-shore landing point of either interconnectors or offshore wind farm connections, and disfavour (by delays, higher connection charges, etc.) competitive rivals. In the case of quasi-merchant interconnectors, other competitors might reduce the arbitrage profits to be earned by NG's subsidiaries. In the case of offshore wind, NG could offer a connection point that would maximise the onshore assets that would go into its RAV as opposed to a potentially more efficient solution, which might require fewer onshore assets. Similarly, to quote from DECC/Ofgem [6]:*"Although NG's offshore transmission business is currently dormant there may be significant opportunity to generate profits in this sector in the future in light of the envisaged £8bn transmission build over the next 20 years."* As such there is a concern that onshore TOs might do pre-construction work that benefits offshore competitive interests.

There must therefore be some concerns that the same owner should both be designing and building the transmission assets and benefitting from interconnections facilitated by such transmission investment, and also concern that potential entrants might be deterred by the perception that they would be relatively disadvantaged. That would continue after connection, as timely maintenance to ensure access to the GB market from the onshore connection point might be less assured.

Similar concerns would also apply if it was decided that competitive delivery would extend to onshore assets. An important aspect to note with these sorts of conflicts of interest is that they do not depend on any explicit communication between the businesses of incumbent TOs, but simply recognition that at the board level the company objective is to jointly maximise total profits from all its interrelated businesses.

Conflicts arising from informational advantages

As explored in [52], NG as both the delivery agent of low-carbon CfDs (including those for off-shore wind) and the transmission planner and SO would benefit from the information supplied for connection agreements and future contracting plans for additional generation, and would thus be in a better position to plan its own commercial activities. This would imply that as transmission system designer and deliverer, NG would be better placed to assess the attractiveness (cost, speed, even future nodal price) of different future connection points. Other merchant interconnectors and OFTOs would lack access to (some of) this transmission planning information and even more to NG's transmission and operational modelling capability that would be helpful in choosing between possible landing points. This could further undermine new entry and by extension potential innovation in the transmission investment.

Even if 'Chinese walls' could be effective, these might not remove the perception of conflicts of interest in the existence of such information. More worryingly, Chinese walls could lead to information, which would have been and should have been made public, being withheld for fear of giving unfair advantage to other businesses e.g. the current connection costs at every node.

Another concern is the fact that NGET is the primary organisation that engages with ENTSO-E. This implies that it potentially has access to information that other TOs do not have. This is important given the role that European institutions are expected to play in the development of the future transmission system through the inclusion of projects (and the associated funding) in the ten year development plans.

Informational asymmetries are inherently difficult to detect (by their very nature, if it was easy to identify the valued information then it would cease to be asymmetrically held). On the other hand their advantage is also likely to be modest, amounting to little more than the cost of replicating that informational advantage. However, the perceived informational asymmetries can lead to a reduction in competition in those activities that are competitive, implying that monitoring the level of competition in areas where informational asymmetries are present.

EMR contract design and transmission planning conflicts

NG has been designated as the body to deliver the EMR, and specifically to design and advise the government on the contracts for low-carbon generation and reserve capacity. As such it would seem well-placed for designing contracts that were spatially differentiated to better minimise overall system cost, and also consumer payments for the new generation.

While the NETSO probably has the best information and skills set to undertake this task, it is less clear that it has the correct incentives, an issue on which DECC and Ofgem have been consulting. Ofgem [52] has now presented the report on conflicts and synergies that it commissioned from KPMG, which concludes that the benefits from the synergies of having NG as the delivery body for EMR were significantly more substantial then the costs due to potential conflicts of interest.

As an overall assessment, while there appear to be a variety of incentives for NG to act in its own interest in ways contrary to the overall public interest the probability of detection of any abusive behaviour appears to be high, and the informational asymmetries appear to be of modest benefit to incumbents, so that overall the potential conflicts, assuming continued regulatory scrutiny, do not seem to be material. However, these conflicts are likely to increase over time with a rising volume of contestable investments (both in interconnectors and offshore connections) and as such their effects might become more material. Nonetheless, further work is needed to assess the materiality of these conflicts of interest now and in the future and identify options for addressing them in case these prove to be material. However, any mitigating options should be proportional to the materiality of the impact and ideally should be designed so that private and public interest coincide, and/or involve process that increases the likelihood of detection.

The following section describes the options we have developed aiming at mitigating these identified concerns.

3. OPTIONS FOR CHANGE

We have developed three high level options aimed at mitigating the key concerns identified with the current regime. The options proposed cover both ends of the spectrum of theoretical routes that can be taken, with an asset-owning TSO and an ISO that (only) plans and operates all the transmission assets owned by other companies. We also analysed a pragmatic solution that is based on minimal changes to the current situation in Great Britain. The options considered are:

- **Improved Status Quo Option:** The philosophy of this option is to preserve the current regimes for onshore, offshore and cross-border transmission and the role of National Grid as NETSO, and to establish a fourth regime for MPPs. In order to address the identified concerns we suggest enhancing the capability of Ofgem/DECC as a buyer of transmission service by establishing a Shadow Independent Design Authority (IDA), which will scrutinise and challenge Transmission Owners' (TOs[5]) plans and co-ordinate planning across regimes through engagement with TOs and project developers. In addition, we propose increasing information transparency regarding connection requests and short-term capacity availability so as to resolve to a certain degree the existing conflicts of interest. Lastly, we consider that it is necessary to improve the interface between regimes (e.g. interconnectors pay the equivalent TNUoS charge), extend good practice schemes (e.g. Network Access Policy) so as to improve co-ordination between TOs and review network operation and design standards and establish enhanced incentives for adaptation of advanced operational measures.
- **TSO Option:** The TSO option requires radical change from the existing arrangements through the establishment of a single entity that will own all the transmission assets and be responsible for transmission planning, delivery and operation of the system across regimes subject to Performance Based Regulation (PBR). From a theoretical perspective this option has the greatest potential for creating an efficient regime, but achieving this requires an optimum PBR scheme (which is difficult to create, to say the least). At the very least, it is necessary that under this option efficient short term and long term transmission pricing would need to be established, otherwise Ofgem/DECC would find themselves in an even more difficult position with respect to regulating a strengthened monopoly. This option would also require divestment of the transmission assets of the existing TOs to the GB TSO. Nonetheless, it is the structure which the majority of the EU countries have, albeit without efficient transmission pricing. An alternative version of this option would be to only establish a TSO onshore and preserve the current offshore and cross-border regimes. This would still require divestments of the Scottish TOs' assets but would preserve the competitive elements of the current regime.
- **ISO Option:** Under the Independent System Operator (ISO) option we envisage the establishment of an independent entity that will plan, facilitate delivery of investment through competitive tenders and operate the transmission system across all regimes. Offshore and cross-border developer-led investments would be preserved but the ISO could also mandate such investments. The ISO governance and grid codes will need to be developed, which will also require a review of the transmission planning and operation standards. Finally, it is expected that the ISO would also be responsible for delivering the EMR provisions. On balance, this option resolves the majority of the identified concerns and

[5] *By TOs in this case we refer to onshore, offshore and cross-border transmission owners*

it could pave the way for future market design improvements, such as efficient transmission pricing.

It is important to note that in future the asset value of offshore, cross-border and the Scottish transmission systems is expected to surpass that of NGET, implying that the majority of the transmission system will be operating under arrangements similar to the ISO option. This evolution of the transmission system necessitates that at some point in the not too distant future a choice will need to be made between the ISO and TSO options. Having said that, the Improved Status Quo option could form an interim solution but we are concerned that a number of the identified weaknesses would remain unresolved. In the following sections for each option we present:

- key characteristics;
- evolution of the current regimes;
- extent to which identified concerns are addressed;
- extent to which regional integration is facilitated; and
- strengths and weaknesses.

3.1 IMPROVED STATUS QUO OPTION

Key Characteristics

The main motivation behind the Improved Status Quo (SQ+) option is to address the identified inefficiencies, while maintaining the current regime setup. The SQ+ option's main feature is to introduce the Shadow IDA to support the Ofgem/DECC decision-making process. Given that under this option Ofgem would effectively remain a buyer of network services, it is important that Ofgem strengthens its capability for in-depth scrutiny and analysis of network investment and provides stronger input to coordination of investment. Currently, the core technical experience and expertise lies with NETSO and the incumbent TOs, aggravating the gap between 'buyer' and 'seller'. The Shadow IDA would undertake Cost Benefit Assessments (CBA) of a range of future GB development scenarios across all regimes. This would provide support to Ofgem in exerting regulatory oversight, ensuring that social welfare is maximised and the needs of future consumers are taken into account.

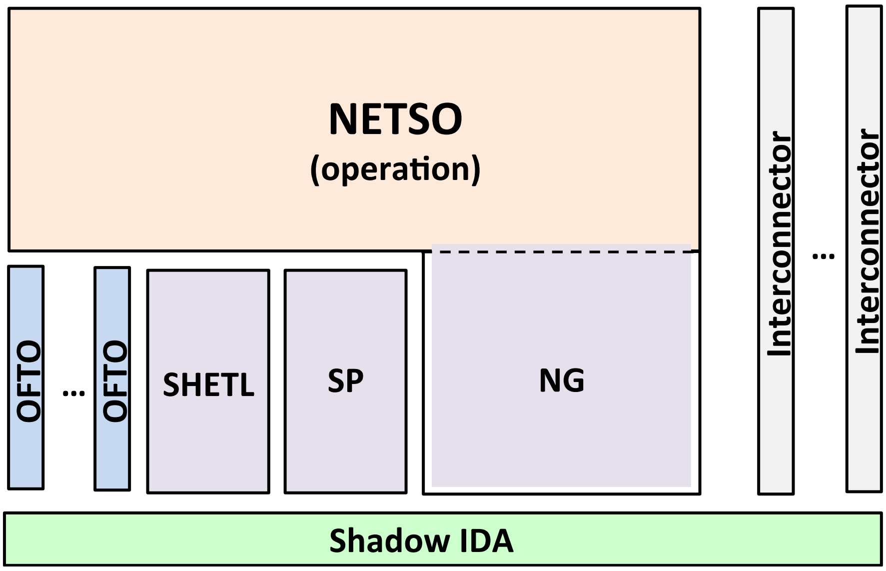

Figure 2: Improved Status Quo Option

More specifically, as displayed in Figure 2, the remit of the Shadow IDA would span all three regimes, which would enable it to develop and maintain a holistic view of the system, coordinate connection applications and administer MPP planning. NETSO would remain the main system operator, while onshore planning activities would remain with the three incumbent TOs. Interconnector and offshore planning would remain largely developer-led, following the current ownership structures. No asset divestment would be necessary under SQ+, meaning that the option could be implemented with a minimal amount of legislative change.

The current TNUoS charging scheme would remain largely unchanged, with the inclusion of interconnectors to facilitate cost-reflective interfaces between the onshore and interconnector regimes and facilitate coordination.

The fundamental inefficiencies associated with the present single-price market remain, but their impact would be marginally reduced through strengthening Ofgem's capability as the principal buyer of network services. The Shadow IDA would be strictly governed by rules that fully specify the processes and methodologies to be followed. In this light, the Shadow IDA would not take a view on the future system evolution, but would provide the necessary expertise to carry out the required tasks. The Shadow IDA rules would be reviewed periodically.

In summary, the responsibilities of the Shadow IDA would include the following:

- Scrutinise the onshore TOs' RIIO business plans.
- Review TO's plans for Strategic Wider Works and make proposals
- Establish full information transparency (e.g. connection requests, short-term network availability). Shadow IDA would act as an information aggregator across the three regimes.
- Coordinating and preventing barriers to entry in the onshore and offshore regimes through calling for an open season process when the need arises.
- Determining the efficient capacity of an interconnector for regulated interconnectors.
- Administer the "golden rule"[6] cost-benefit check for merchant interconnectors.

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[6] *The golden rule refers to the traditional cost-benefit test of an investment i.e. that net welfare is higher than the costs. In the case of merchant transmission investment the private benefits of the project sponsor (congestions surplus) might be higher than the costs but the project might lead to an overall reduction in social welfare. Such a project would not adhere to the golden rule and should be disallowed.*

- Support Ofgem/DECC in administering auctions for the cap-and-floor of regulated interconnectors.
- Support Ofgem/DECC in the auction of offshore assets.
- Facilitating the MPP planning process through a transparent Cost Benefit Analysis methodology that utilises a set of accepted scenarios and a reference cost database, compiled and regularly updated through stakeholder consultations
- Supporting Ofgem in administering auctions for the detailed design and delivery of MPPs.

Some other key considerations under SQ+ would be:

- Improvement of the interfaces between regimes through cost-reflective charging (e.g. make interconnectors pay TNUoS charges).
- Improved coordination between TOs at the operational level by formalising and extending good practice schemes (e.g. Network Access Policy).
- Review of network operation and design standards to encourage adaptation of advanced network technologies and novel operational measures that would enhance the utilisation of the existing assets.

Evolution of Current Regimes

Onshore Planning & Delivery

Onshore planning would still remain with the three incumbent TOs and be determined through the 8-year RIIO plan. Onshore TOs' planning goal is assumed to remain profit maximisation subject to regulatory oversight, meaning that TOs are inherently incentivised to propose asset-heavy solutions. As a result, the regulator's ability to effectively scrutinise the plans and permit only cost-efficient proposals is crucial. To this effect, the Shadow IDA would challenge TOs' plans and require evidence that alternative solutions have been considered, including the use of advanced operational measures. This would drive TOs to adopt more transparent planning methodologies and explicitly consider a wider array of solutions.

The delivery of onshore assets would largely remain the same. Delivery and ownership of assets would be directly appointed to the incumbent TOs. Although international experience suggests that competitive delivery schemes can significantly reduce costs, currently there are no major concerns with delivery efficiency of onshore projects in GB. For example, even though the need case for the Western Bootstrap has been questioned, its delivery cost seems efficient. TOs are exposed to deviations from the agreed revenue allowance and thus are already using competitive tendering to reduce costs.

In the long-term case where a deeper and more cost-reflective charging scheme was introduced, international experience (Australia, Appendix C.2) suggests that there would be value in making this 'internal' tendering process public. This would be done primarily to reduce scope for legal disruptions (developers bringing incumbents to court) and perceived conflicts of interest, particularly in the case of vertically-integrated Scottish TOs.

However, for the time being, given the lack of sufficient evidence of inefficient delivery from incumbent TOs as well as the fact that separating planning, design and delivery will inevitably result in some loss of synergies, under the Status Quo + option it may not be necessary to impose compulsory competitive tendering for asset delivery. In addition, onshore tendered delivery could exacerbate the perceived and actual conflicts of interest of NETSO and potential independent onshore TOs. This would increase the business risk profile of the assets and the return requirements of new entrants, given that a competitor would be operating their assets, whose availability would dictate their revenue.

With regards to the Strategic Wider Works, the planning responsibility would move from onshore TOs to the Shadow IDA, which would undertake a holistic cost-benefit analysis, identifying efficient boundary reinforcements beyond the TO baseline plans. A long-term scenario analysis would be performed in conjunction with constructive engagement with stakeholders, ensuring that future consumers' and users' needs are taken into account. Ultimately, the goal would be to identify no-regret boundary reinforcements that lead to wider benefits. However, the Shadow IDA would not go as far as specifying specific solutions. Instead, similar to the CARIS process used by the New York ISO (Appendix C.7), its periodic CBA would be used to 'prioritise' areas for improvement and give an indication of benefits associated with the relief of specific constraints (as was done by the ENSG).

The Shadow IDA remit could be extended to include inviting developers (transmission, demand, generation, storage etc) to propose operational solutions, such as an inter-tripping scheme to increase a boundary transfer limit. Further analysis of each proposal would be undertaken to determine their cost-efficiency, with the originally-calculated net benefit acting as a reserve threshold. Proposals deemed efficient would go ahead, with the developer being granted asset delivery and ownership and/or sign a service contract with NETSO. Similar to the status quo, asset operation would be transferred to NETSO or the Scottish TOs as appropriate. Naturally, incumbent TOs would also be allowed to participate. The main advantage of this approach is the extended scope for innovation through market solutions as well as the integration of both design and delivery in a competitive framework.

Offshore Planning & Delivery

Offshore planning would remain a developer-led activity. The role of the Shadow IDA would be to facilitate coordination by reducing the perceived conflicts of interest and perverse incentives that arise as elaborated below. It could support Ofgem in carrying out auctions and facilitate more complex auctions by providing reserve configurations.

In the current situation, offshore wind farm developers can privately capture any scale economies benefit and are thus incentivised to constructively engage with other developers in order to pursue cost-effective solutions. In addition, coordination can lead to more economic onshore solutions. Analyses have shown that the overall benefit of coordination could be up to £3.5 billion (c.15% of total costs [9]). To this end, ensuring that coordination opportunities are pursued is important. However, initial experience suggests that there is a lack of willingness to coordinate. One reason for this is the reluctance to share commercially-sensitive information with competitors, including NETSO.. With respect to onshore works, TOs have no benefit in proposing coordinated connections to shore; RAV-based incentives favour asset-heavy solutions. In the same vein, developers themselves are partially indifferent to their landing point, since onshore reinforcement costs are socialised.

To address the above concerns, the Shadow IDA would be responsible for holding an open season when the need arises, to reduce barriers to entry. In addition, it would be acting as the coordinating hub, a function currently administered by NETSO through the Interactive Queue process. IDA, with its independent status, as opposed NETSO with perceived conflicts of interest given commercial interests in offshore transmission, would facilitate constructive engagement with candidate developers. Furthermore, it would directly interface with the incumbent TOs, with the intent of scrutinising the connection scheme being proposed. Although offshore planning would still fundamentally be developer-led, the Shadow IDA would ensure that all coordination opportunities that lead to wider benefits are explored.

With the increasing size, complexity and scope for coordination in Round 3 projects, more complex auctions would be needed to capture the benefits of the underlying economies of scale and opportunities for wider benefits. As suggested in [10], Ofgem could invite offers for 'packages' of transmission assets, where instead of offshore generators pre-specifying the required service, design and delivery are considered together. As a result, more holistic solutions could emerge. The Shadow IDA would support Ofgem/DECC and carry out the tasks of exploring advanced procurement alternatives and assessing their applicability to the GB offshore regime. The Shadow IDA would also support Ofgem in managing complex auction processes that inherently require a well-informed buyer.

Cross-border Planning & Delivery

As discussed in the previous section, depending on the cap&floor levels, cross-border transmission could evolve either as a merchant or regulated activity. In addition, under SQ+, we propose that interconnectors would be subject to TNUoS charges, incentivising interconnection developers to actively pursue an efficient connection to the grid. Furthermore, a Shadow IDA would limit the perceived conflict of interest involving the onshore TOs and their private functions. To this end, a Shadow IDA would scrutinise incumbent TOs' connection proposals to interconnection developers, ensuring that efficient solutions are brought forward.

In the merchant case (with wide or no cap&floor levels), which represents the status quo, interconnection planning would be solely subject to a cost-benefit analysis (golden rule test) performed by the Shadow IDA to ensure that expected benefits outweigh costs and potentially assist with setting the cap&floor levels. As in the current situation, the asset would be constructed, owned and operated by the investor with revenue stream linked to the sales of Transmission Rights and/or price differentials and fully exposed to market, construction, commercial and availability risks.

At the same time the shadow IDA as part of its regional co-ordination mandate would facilitate a cross-border planning process, which would involve identifying eligible interconnection projects. These projects could be identified through a centralised CBA process carried-out by the shadow IDA or suggested by developers, in which case they would be subjected to the golden rule test. The delivery of these projects could be tendered. As mentioned above, the shadow IDA would perform the necessary cost-benefit analysis to determine the capacity level that maximizes expected social welfare. As international experience in Chile (Appendix C.4) has shown, firms still have an incentive to undertake such analyses and propose projects since this gives them an information advantage in preparing their bids. It follows that, as with OFTOs, new firms participating in these auctions would be thoroughly scrutinised for technical competence and financial deliverability.

MPP Planning & Delivery

Currently, there is no formal platform for planning of MPPs. By definition, these projects involve multiple interfaces and significant anticipatory elements. As a result, incumbent TOs, offshore developers and OFTOs are not incentivised to pursue such projects, since they cannot privately capture the benefit of an MPP investment.

Under SQ+, a new MPP regime would be instituted, and Shadow IDA made responsible for planning such projects. Projects that would fall within the new MPP regime would be offshore links providing wider benefits, including onshore boundary transfers enhancement through meshed connections offshore and the combination of offshore assets and cross-border interconnectors. The planning process would be similar to the arrangement proposed for the onshore Strategic Wider Works. The Shadow IDA would perform periodic analysis to indicate MPPs leading to wider benefits, while also allowing proposals from stakeholders. Market solutions would then be solicited through an auction process, where participants would propose solutions and bid for a regulated return on their investment decoupled from asset utilisation. Ofgem would be responsible for administering these auctions, acting as the purchaser of transmission services. As mentioned before, complex auctions could be a suitable vehicle for enabling procurement of such services. Shadow IDA support would be essential in quantifying the holistic benefit of different proposals and determining the asset combination that leads to maximization of social welfare. The winning developer would be granted delivery and ownership of the project.

Addressing Status Quo concerns

Incentives framework for transmission investment and operation

Whereas the Shadow IDA would scrutinise and challenge the TOs investment plans it is unlikely that the identified issues would be resolved. This is because the Shadow IDA would not have an informed view of the operational implications of investment decisions. The importance of this shortcoming will depend to some degree on the competence of the Shadow IDA as well as the potential inefficiencies that might result due to limited integration of advanced operational measures. Furthermore, problems with setting incentives for system operation will remain. A focused Network Innovation Competition (NIC) complemented by the update of planning and operation network codes could mitigate to a certain extent this concern.

Lack of co-ordination

Facilitating co-ordination will be one of the primary mandates of the Shadow IDA and as such it is expected that to a certain degree the lack of co-ordination concern would be addressed. Increased information transparency extending good practice schemes (e.g. NAP) to improve co-ordination between TOs could also help but it is unlikely that this issue would be effectively resolved.

Regional co-ordination and the EU Target Model

Under this option, as explained previously, cross-border transmission investment will be primarily undertaken by independent developers. This implies that efficient regional co-ordination might be difficult to achieve given the large number of parties involved. In addition, it is unclear how Great Britain will be represented at a regional level, in particular in ENTSO-E. Overall, these points might imply that efficient implementation of the EU Target Model and regional co-ordination might be hindered under this option.

Conflicts of Interest

The introduction of the Shadow IDA as the coordinating hub for connections and the increased information transparency will largely address the concerns related to information asymmetry. However, other important concerns such as the conflicts among TOs and between incumbents and competitive businesses will remain largely unresolved. The resolution of these would entail more extended changes, such as the unbundling of network ownership and planning.

Strengths & Weaknesses

As mentioned earlier, a key strength of the SQ+ option is in its focus on improving the current arrangements while introducing a moderate amount of change. The proposed framework does not include radical changes such as asset divestment or the institution of an independent System Operator. For this reason, key concerns such as conflicts of interest would remain unresolved.

However, SQ+ would enable the regulator to retain the option of a future move towards more fundamental regime changes, while making best use of the rules and processes already in place.

Another concern could be that SQ+ is a regulation-heavy proposition that involves the introduction of another institution (or the significant expansion of the existing capabilities of Ofgem/DECC). This would hardly address the concerns voiced by some renewables developers who highlight the lack of a streamlined connection process. In response to this, it is worth noting that the goal of the Shadow IDA would be to simplify the connection process and provide a clear route to market, rather than add an unnecessary layer of complexity.

3.2 TSO Option

Key Characteristics

Under a transmission system operator (TSO) framework, one single party owns the transmission network as well as operates it. Such a party is accountable for providing access to new users, operating, planning and delivering network infrastructure. In this report, we differentiate between two main options associated with this framework for GB. The first option bundles the above activities only over the current onshore transmission network (onshore TSO) while a second one bundles them across the three transmission regimes, i.e. onshore, offshore, and interconnector (GB TSO). Both two would require horizontal integration of transmission facilities under the main incumbent transmission owner, i.e. National Grid as displayed in Figure 3.

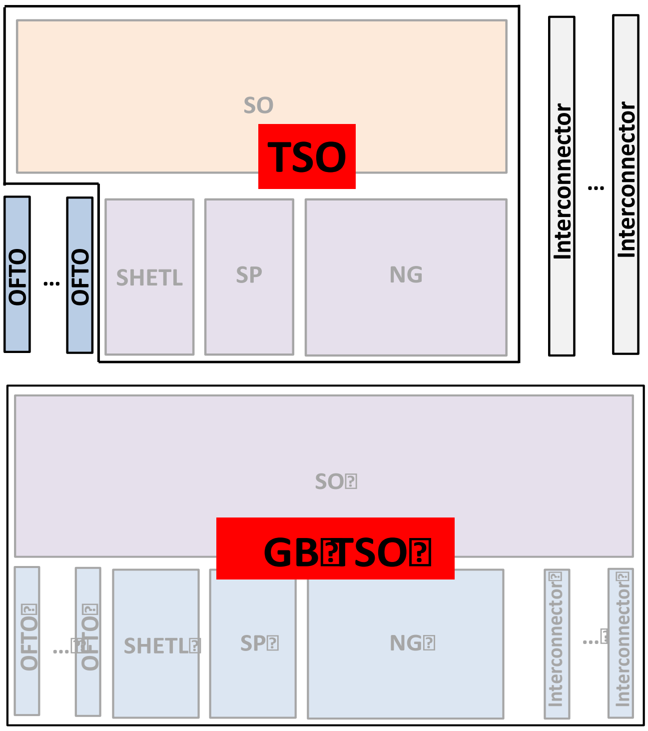

Figure 3: TSO options that bundle operation planning and delivery over the onshore network (upper) and across the three regimes (lower)

Under the above options, the governance of the TSO would not be fundamentally different from that of the current TSO of England and Wales (i.e. National Grid) and therefore it would remain the case that it will not to be allowed to own generation or retail businesses or be dependent on affiliated market participants, in order to eliminate conflicts of interest. Likewise, in the case of the onshore TSO, a clear functional separation for the unregulated lines of business like interconnectors would need to be imposed, potentially going even further than at present and requiring complete independence. Furthermore, because a TSO is fundamentally a for-profit entity, it would need to be exposed to a tailor-made and adequate system of performance based regulation (PBR) and ruled according to an array of network codes that promote transparency in all network activities (operation, planning and delivery), in order to align its economic incentives and actions with those that increase social welfare. This is further developed next.

Evolution of Current Regimes

Under the TSO options, it is envisaged that the current onshore regime in England and Wales will be expanded to the entire onshore network (onshore TSO option) or all three transmission regimes (GB TSO option). Thus, the TSO would be responsible for network operation, facilitating access as well as co-ordinating planning and delivery across regimes, timescales and on a regional basis through engagement with industry stakeholders, the regulator, DECC and EU counterparties.

As a result, the role of Ofgem/DECC would shift from a buyer of transmission service to only the designer of the incentive schemes and facilitator of Constructive Engagement (CE) among the market participants.

A prerequisite of a successful application of CE is that network pricing becomes truly location-specific, reflecting costs according to real benefits to users. This would include implementation of Locational Marginal Prices (LMP) in the short term together with the allocation of fixed transmission costs on a “beneficiary pays” basis in the long term as established in Argentina (Appendix C.1), Brazil (Appendix C.3) and Chile (Appendix C.4).

Under these conditions, network planning would be carried out through a process, with potentially Ofgem and DECC providing input on behalf of consumers (in case of absence of strong consumer advocate groups) and future user’s needs. The process could be broadly based on that found in the aviation sector, which was introduced in 2005 by the Civil Aviation Authority. Under this approach a negotiation takes place at each regulated airport between the airport and its users (the airlines) as an important input into the periodic price review. The areas covered are substantial and are illustrated below (Figure 4). They arose precisely because of the perceived inability of the regulator to evaluate the proposals of the regulated firm in a conventional bilateral regulatory negotiation.

This process seems to work, though in unexpected ways. At Heathrow, a Joint Steering Team (JST) - involving 25 representatives from 92 airlines - has recently reached agreement on 4 of the 6 elements of the CE approach above as part of the 2013-18 price control period. This included agreement on around 2/3 of the proposed investment programme at the airport (with the airlines arguing for more spending). CE is facilitated in airports because investment beneficiaries tend to pay. CE has been time consuming and lengthens the price control review process. CE was initially criticised because of the failure to reach agreement on investment requirements at Stansted in 2005, with an impasse between BAA and at least some of the airlines over the scale of investment requirements. However with hindsight this reflected the fact that ‘do nothing’ in the event of a failure to agree was not a credible threat for the negotiating parties (this is the default position in US regulation). A key part of the negotiation on investment is about agreement on ‘triggers’ and ‘floors’, i.e. what developments in demand would lead to the commencement or abandonment of planned investment. While agreement on the quantity of investment is the most contentious issue in the negotiations, agreement on other issues such as service quality targets and operational efficiency targets seems to have been much less difficult.

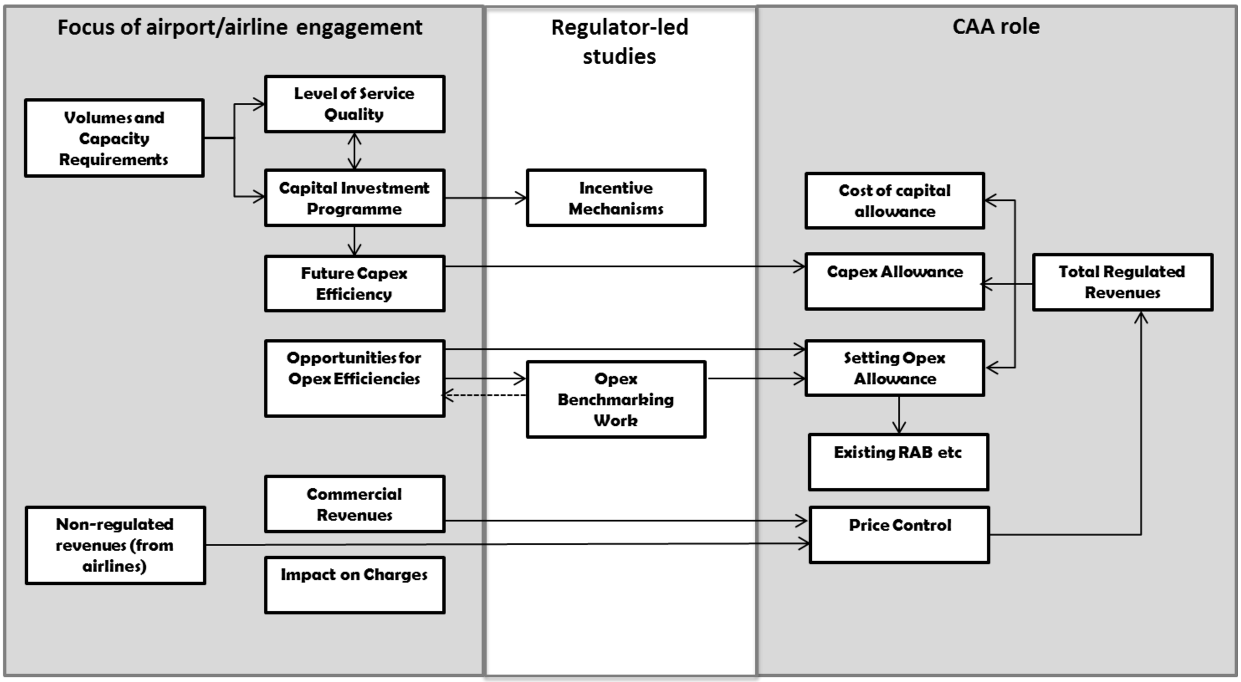

Figure 4: Illustrative CE process with RAV based approach, *Source: CAA (2012, p.15 [13]).*

In the electricity sector, the underlying assumption needed to accept a TSO option is that regulation will provide the necessary incentives to align benefits to the TSO and to society. In fact, if an adequate performance based regulation (PBR) were in place, bundling network ownership and operation would lead to optimum operation, planning and delivery by taking advantage of the synergies from combining SO and TO functions, particularly in asset operability and flexibility assessment. Furthermore, the TSO could be allowed to undertake a holistic balance of short and long-term network operation and investment by internalising the associated costs through the incentives schemes and the response of network users through the constructive engagement process. This would minimize the need for the regulator to scrutinise system operation, planning and delivery activities.

Nonetheless, as opposed to the aviation sector, where the regulated output can be clearly defined (number of passengers served) in electricity transmission, defining the output and the associated cost function is much more challenging. As elaborated in [14][7] the transmission cost function displays non-convexities and as such whether an efficient regulatory formula could be established is still an open question, even in the presence of efficient pricing.

Finally, in order for the TSO option to function, restructuring of current asset ownership will be needed (i.e. asset divestment of TOs in Scotland, and perhaps OFTOs and interconnectors in GB TSO option).

Addressing Status Quo concerns

Incentive framework for transmission investment and operation

Under any PBR regime, the balance between cost minimisation, quality and performance incentives, which has to be determined by the regulator, is challenging [15].

[7] *This study identifies a transmission investment regulatory framework which exposes the TSO to both regulated and congestion surplus revenue with different weights, showing that the TSO would invest optimally. However, this in only ensured if the transmission investment cost function is well defined and convex (which is not the case in practice).*

Despite the above, the TSO options would in principle be able to deliver optimal level of network capacity to consumers and could reverse the bias towards asset heavy solutions and use advanced operational measures as alternative non-network solutions since these would increase profitability (together with social welfare). However this would depend on the following strong assumptions:

- Efficient pricing is established;
- PBR can be designed and an appropriate output defined; and
- CE process is effective.

Coordination

Multiple coordination problems between TOs and NETSO, existing and future users' needs, different transmission regimes, and network investment at regional level (i.e. EU) would be clearly resolved through having a single GB TSO that mandates (subject to Ofgem approval on major investments and subject to a dispute process for connections) all network investment and operation. Under the GB TSO option, onshore, offshore and interconnection operation will be jointly optimised and network planning will be proposed by a single party that minimises overall network costs of investment and operation, taking advantage not only of the economies of scale but also of wider onshore benefits associated with offshore and interconnector assets. This is very important in the case of MPPs. For example, a TSO would engage with international counterparties for regional coordination and offshore developers for MPPs combining interconnection and offshore transmission. Likewise, the TSO would need to include integration of offshore wind in onshore undersea bootstrap planning in order to minimise overall GB costs. Also, offshore networks could be planned strategically to anticipate users' connections and so minimise entry barriers and environmental impacts.

Under the onshore TSO option, on the other hand, although current issues regarding coordination of onshore operation and maintenance will be resolved, coordination of offshore, interconnectors and MPP in operation and planning would still be market led but presumably more efficient due to the improved transmission pricing arrangements and TSO incentives.

Regional co-ordination and the EU Target Model

Under the TSO option, GB would adopt a similar set of arrangements to those found in most European countries, based on which the TEM has been developed. The GB TSO option would facilitate more efficient regional co-ordination, especially since it will be the only entity engaging with regional counter-parties. However, designing a PBR scheme that would also include the provisions of the TEM would further complicate an already very complex task.

Conflict of interest

The existence of a single party will resolve conflicts between multiple onshore TOs and those between TOs and generation, especially in Scotland since a single TSO will govern the overall onshore grid. Moreover, conflicts involving competitive versus incumbent businesses (where the TSO could develop competitive offshore networks and interconnectors) will be also removed under the GB TSO option due to the presence of a single party that will control all network investments, albeit such conflicts will be maintained under the onshore TSO option. In fact, in the latter full divestiture of competitive activities of the onshore TSO would be required.

Regarding the interactions between network and generation planning and operation under the Electricity Market Reform (EMR), TSO incentives may represent a major drawback in the future since they have been initially designed to deal with optimum network activities only. Further tasks such as design of contracts for difference and generation auctioning may interact with network planning, creating distortions and perverse incentives.

Strengths & Weaknesses

There are a number of advantages and disadvantages associated with the TSO framework that the literature has identified earlier [14], [16] & [17].

Strengths:

- It is the ideal model in theory.
- Its independence is structural.
- It has a focused business model.
- A for-profit TSO is easier to regulate with PBR since objectives and incentives are clear.
- It minimises the interfaces between operation, planning and delivery as well as the associated transaction costs.
- It is an informed buyer of network assets.

Weaknesses:

- It requires well-developed PBR, which is unclear whether it is theoretically possible to develop even with efficient transmission pricing.
- Ownership separation for the unregulated lines of business (e.g. interconnections).
- Restructuring to increase the degree of horizontal integration of TSO could be challenging politically.
- Delivery of all investments is dependent only on a single commercial entity, which needs to raise financing and do so efficiently. Experience from Germany (e.g. TenneT having problems in financing offshore assets) suggests that even TSOs might face such problems.
- Over-reliance on expertise of a single entity with limited resources might limit innovation.

3.3 ISO Option

Key Characteristics

Under this option, an Independent System Operator (ISO) would be established, with key responsibilities for transmission system operation planning and for administering system delivery.

As displayed in Figure 5 the GB ISO would replace NETSO as the system operator and would be responsible for overall co-ordination across regimes. However, the ISO would not own any transmission assets and its structure and scope would be broadly based on the ISOs found in the US and Latin America[8].

A key distinction to the current NETSO structure would be that instead of relying on profit maximization incentives the majority of the ISO functions would be dictated through grid codes and rules and a broad mandate to maximize social welfare. This equates to minimizing transmission investment, congestion costs and un-served demand, given demand and generation power injection/withdrawals and entry/exit decisions. As a result, the ISO would internalise these costs and operate and plan the system accordingly. In order to ensure this is done efficiently, the most important characteristic of the ISO is its independence from any market participants.

[8] *For more details on the transmission planning and delivery experience in markets with an ISO refer to Appendix C*

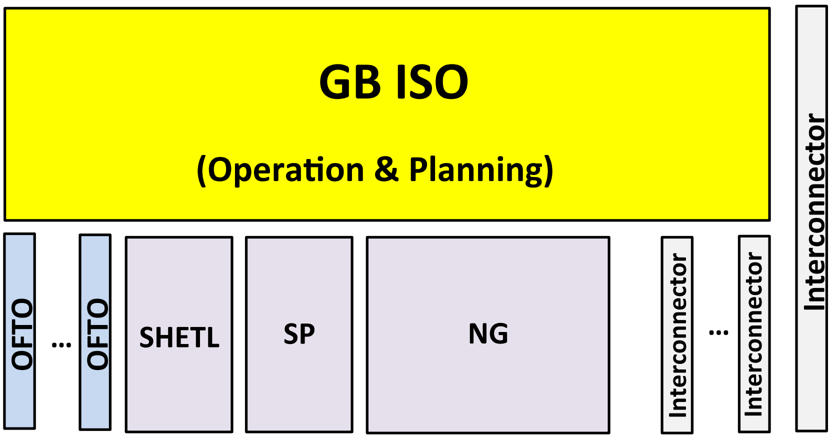

Figure 5: ISO Option

In summary the responsibilities of the GB ISO would include the following:

- System operation supported with the ability to contract with generation, demand and TOs to maximise the utilisation of existing assets, following a clear set of rules and grid codes and updated network operation standards;
- Facilitating the transmission planning process through a fully transparent Cost Benefit Analysis (CBA), which would involve stakeholder engagement regarding development of future demand and generation scenarios;
- Scheduling and co-ordinating transmission system outages with TOs and generation and having the ability to mandate maintenance plans[9];
- Offering connection agreements to market participants;
- Administering competitive tenders for the delivery of certain assets onshore, offshore and cross-border;
- Mandating incumbent TOs to undertake transmission investment;
- Co-ordinating with merchant offshore and cross-border project developers, ensuring that these investments adhere to the golden rule i.e. that the net benefit is higher than their costs;
- Administering BSUoS and TNUoS cost recovery and payments;
- Co-ordinating the development of MPPs and engaging with ENTSO-E and other EU counter-parties for regional network planning;
- Administering Network Innovation Competitions (NIC);
- Supporting Ofgem/DECC with market design and regulation potentially assisting in market power monitoring and carrying out CBA of market design changes as appropriate;
- Administering EMR and in particular the design of CfD contracts and capacity market.

[9] *In Chile for example the ISO co-ordinates the maintenance schedules and TOs are required to follow these. In general, as mentioned in [16] in some jurisdictions ISOs have been expanding their responsibilities to a degree that made the TOs passive network owners.*

Overall, the responsibilities and actions of the ISO would broadly match those of the NETSO, implying that this option would not require substantial market code changes.

In line with the international experience, elaborated in Appendix E, the ISO would be a public, not-for-profit entity, managed by a board of directors and could be supported by an advisory board representing the interests and expertise of all market participants and TOs.

Grid codes, well defined process and rules, supporting decision making through transparent social welfare maximization CBA (all of which would be reviewed regularly against best international practice), will ensure that ISO maximises efficiency of system operation. These will be the key for dealing with criticisms of the ISO option involving (a) risk-aversion and thus conservative system operation and planning, (b) ever-expanding area of influence and undertaking activities for which others pay and (c) a lack of internal cost control.

With respect to ISO funding, the current cost recovery mechanism through BSUoS charges would be appropriate. Since the ISO would not invest in any assets the level of annual costs is expected to be similar to the current NETSO costs. In order for the ISO to be able to strike contracts cost-effectively, the government, through guarantees for cost recovery, will ultimately provide its credit (this would be similar to the Renewable Obligation Certificate (ROC) revenue collection and distribution system).

The ISO could be established through divestment of the current NETSO from NGET. The fact that the NETSO does not have any significant asset should minimise the complexity of this process.

Similar to the Improved Status Quo, the ISO option does not require fundamental changes to the current charging arrangements but a rationalisation so as to resolve the inconsistencies across the different regimes. We note that going forward the value of assets offshore, cross-border and the Scottish TOs is expected to surpass that of NGET, implying that the majority of the transmission system will be operating under arrangements similar to the ISO option.

Evolution of Current Regimes

Onshore Planning & Delivery

Under this option it is envisaged that the onshore planning & delivery process would change significantly and be driven primarily by the GB ISO. The GB ISO would engage with industry stakeholders, DECC and regional counterparties to establish a number of future generation, demand and interconnection scenarios. With inputs from the TOs and other market participants, the ISO would perform a transmission planning CBA by taking into account security standards, policy targets, investment and congestion costs. The CBA would consider a number of competing technologies such as advanced operational measures, non-network solutions (demand, generation, storage) as well as investment in primary assets. The CBA would be based on a minimum regret framework taking into account the optionality that different investment solutions offer[10]. From this point, the ISO could make a final decision regarding the investment plan and then mandate the incumbent TOs to undertake the investments or facilitate competitive tenders for their delivery (deep ISO).

On the other hand, in order to encourage innovation and consider alternative propositions, the output of the above CBA could be split into two groups: (a) set of 'must have' boundary capacity

[10]ISO could initiate anticipatory consenting to ensure that when and if investments are needed, these could be implemented efficiently.

enhancements[11] and (b) set of a potential projects (across different technologies) that would deliver the desired output as well as a "reserve" solution produced by the ISO. The ISO would then invite market participants to submit detailed proposals for each project (or bundles of projects) and would carry out another CBA determining the cost/benefit ratio for each proposal against the reserve solution. If the ratio is favourable, then this solution would be implemented, otherwise the ISO would mandate or auction the delivery of reserve solutions. Such a process is already facilitated by the New York ISO (Appendix C.7). In order to encourage as much as innovation as possible, it is suggested that sponsors of market led solutions could opt not to build the project and instead earn an innovation premium computed as a percentage of the cost difference between the reserve solution and their proposal. In this case, the delivery of the project would be competitively tendered (above a certain financial threshold) or (below a certain financial threshold) delivered by the incumbent TOs.

It should be noted here that offshore and interconnection projects could be among the solutions considered for enhancing onshore capacity. As a result, through this process, a possible solution could be enhancing or expanding the offshore or cross border network. The ISO would recognise such opportunities and invite market participants to submit proposals allowing them to either earn innovation premiums or a RAV-based revenue by building their own assets.

Offshore Planning & Delivery

In the case of a deep ISO, the OFTO regime would be overturned and offshore transmission planning would be undertaken by the ISO and the delivery competitively tendered.

However, there may be benefits in retaining the competitive elements of the current arrangements. For more complex offshore projects with wider benefits, these would be planned and delivered through the advanced onshore planning and delivery process described previously.

Interconnector Planning & Delivery

Similar to offshore planning, the interconnection planning process could be undertaken exclusively by the ISO, without any merchant projects[12] and delivery competitively tendered with aspiring TOs bidding on cap and floor levels.

Alternatively, the cross border regime could be broadly the same as the one described in the Improved Status Quo section.

MPP Planning & Delivery

Under a deep ISO, MPPs would be planned through the CBA by the ISO and delivery competitively tendered.

Alternatively a more competitive planning and delivery process could be established. Two types of MPPs could be considered (1) offshore and cross-border projects that have wider benefits which would implemented through the advanced planning and delivery process (as onshore) or (2) market led MPPs, assuming that the identified inconsistencies across regimes are resolved.

[11]For which there is either user engagement or there is a view that they serve future consumers' needs under an anticipatory investment framework or provide significant optionality.

[12]In any case, if the ISO could mandate regulated interconnectors it is highly unlikely that independent interconnectors would be developed on merchant basis due to the very high risks that their expected price differentials would be eroded due to the regulated investment

Addressing Status Quo concerns

Incentive framework for transmission investment and operation

Under the ISO option this concern would be resolved to a large extent since the mandate of the ISO would be to maximize GB social welfare through the co-optimization of transmission planning and operation and the use of competitive tendering.

As elaborated in the previous sections the overall efficiency of transmission investment would depend on the scope of the ISO as well as the following:

- ISO governance and Ofgem's ability to regulate the ISO costs;
- The effectiveness of the grid codes and transmission planning and delivery rules and processes.

Concerns that would largely remain are the ability of dealing with uncertainty as well as the inefficient generation siting due to lack of cost-reflective transmission pricing. Hence, a certain degree of overinvestment is still likely but this would be driven by generation and demand siting decisions rather than perverse investment incentives due to the commercial considerations of the ISO.

In order to increase stakeholder engagement as well as promote innovation, advanced planning processes such as the one presented in the previous section and ISO administering Network Innovation Competition could be adopted.

Lack of co-ordination

This would be resolved as the co-ordination at all levels (operation, across regimes, current and future users and regionally) would be achieved through ISO planning. This is true for both the deep ISO option, where the ISO centrally co-ordinates planning, delivery and operation regionally and across timescales and regimes, and under the "NYISO" option where the ISO would facilitate network user led co-ordination through an advanced planning and delivery process.

Regional co-ordination and the Target Electricity Model

The ISO would be responsible for co-ordinating with EU counterparties and participating in ENTSO-E activities. Free of asset ownership, the ISO would identify efficient investments in non-GB located assets that might alleviate the need for GB reinforcements. This is line with the aspirations of the TEM but would definitely be against the economic interests of national TOs under the existing arrangements.

Conflicts of Interest

Since the ISO will be independent and not for profit, under this option all the existing conflicts of interest would be resolved. However, an entity like the ISO may suffer from conflicts of interest originating in the bureaucracy of the organisation. However, the core ISO functions would be carried out in line with well-defined and transparent market codes, rules and implementation of processes that will be regularly reviewed against best international practices. Hence the remaining concern would be associated with managing ISO operational costs. However, these costs are expected to be modest and could be mitigated effectively.

A potential issue could be one of behavioural bias rather than conflicts of interest, with the ISO board and employees (especially if the ISO is staffed with employees from NETSO and other TOs) possibly favouring the solutions of incumbents. Again, if sufficient managerial incentives and strong regulatory oversight is established, then the independence of the ISO would not be compromised. This does not seem to have been a problem in most jurisdictions which have an ISO.

Strengths & Weaknesses

The key strengths of this option are summarised as follows:

- All the concerns with the current regimes would be to a large extent effectively resolved
- The institutional changes required would not be significant given that the ISO would be broadly based on the current NETSO.
- The regulatory scope of Ofgem with respect to transmission planning and delivery would be significantly reduced and limited to ISO cost oversight, dispute resolution as well as reviewing the effectiveness of the grid codes, transmission investment processes and finances.
- The ISO is likely to support and promote future market design enhancements, such as a move towards LMPs, financial transmission rights and capacity markets as has happened in the US.

To a large extent the efficiency of the ISO option would depend on the design of the network codes, rules and transmission investment processes, which would be continuously reviewed and enhanced. In the case of a deep ISO a distinct disadvantage is that no assets would be developed on a merchant basis, which could limit the level of stakeholder engagement and integration of innovations. However, the advanced planning and delivery process, based on the NYISO concept, would promote innovation if implemented effectively.

The most important but inevitable weakness of the ISO option, which is also its strong point, is the separation of transmission operation and ownership and the loss of the associated synergies. This would limit the ability of the ISO to operate the TOs' assets in a flexible manner, as the latter would aim to extend their lifetime by promoting their conservative operation. To a certain degree the ISO could contract with the TOs for the flexible operation of the assets or provide warranties in case of damage. Nonetheless, experience from other sectors (in particular railways (Appendix D)) and current experience with the OFTO and Scottish TOs assets operated by the NETSO, suggests that defining such contracts can be challenging. On the other hand, the status quo and improved status quo, with the exception of England & Wales, also suffer from this problem and will increasingly do so as the RAV of offshore and cross-border assets overtakes that of NGET. A similar argument can be made with respect to transaction costs, which will naturally increase under a separation of ownership and operation.

4. SUMMARY AND FURTHER WORK

A summary of the key strengths and weaknesses of each of the proposed options is presented in Table 2. The Status Quo+ option has the obvious advantage of requiring the minimum amount of change and possibly has the lowest implementation costs. Moreover, it would provide time to evaluate how effective coordination and delivery of networks across different regimes is, as well as to consider further evidence for or against change as this becomes available. On the other hand, as explained in Section 3.1 a number of the current concerns would not be addressed and the challenge of the regulatory task of Ofgem would continue to grow, as investment levels and asset complexity escalate.

The GB TSO options have a number of benefits, the most important being that a single entity could internalise the costs of investment and operation efficiently and deliver an optimum transmission system. This can lead to significant synergies both with respect to operation and ownership as well as planning, designing and delivering the transmission system, which in turn leads to low transaction costs. Moreover, this option is the dominant one in Europe. However, there are a number of pre-requisites for this option to deliver efficient network operation and investment including:

- Efficient network access pricing with beneficiary pays concept is established;
- PBR can be designed and an appropriate output defined; and
- Constructive engagement process is effective.

In addition, this option would require existing TOs to divest all their transmission assets to the GB TSO.

As explained in Section 3.3 the ISO option can potentially resolve the majority of the weaknesses identified with the current regime as well as promote innovation and increased stakeholder engagement through an advanced transmission planning and delivery process. Because of the non-profit nature of the ISO, the key concern is that the ISO is likely to be very risk averse and tend to favour conservative system planning and operational measures. However, the ISO would need to follow grid codes and rules in operating the network which would be supported by established social welfare maximization CBA, rather than commercial incentives. Reviewing the list with the key ISO responsibilities, for the majority of the items it is evident that the actions are a matter of applying market codes and following processes. These rules and CBA would be reviewed periodically against best international practises. In order to benefit from optimising trade-offs between short-term operation and investment costs, the GB ISO would be able to contract with incumbent TOs and with demand and generation parties for the provision of network services that would reduce network constraint costs and enhance utilisation of existing assets. We also note that going forward the asset value of offshore, cross-border and the Scottish TOs is expected to surpass that of NGET, implying that the majority of the transmission system will effectively be operating under arrangements similar to the ISO option.

Table 2: Key strengths and weaknesses of proposed options

	Status Quo+	GB TSO	GB ISO
Key Strengths	• Minimum change focused on improving current regimes • Optionality to reconsider as more evidence emerges	• Theoretically optimum option • Synergies from combining SO and TO functions, particularly in asset operability and flexibility assessment • Integrated design delivery and operation • Low transaction costs • Preferred practice in Europe	• Resolves most current concerns: implements efficient system operation, removes conflicts of interest, provides effective coordination across regimes and within the region • ISO can promote future market design improvements • ISO option with advanced planning and delivery process can potentially lead to more active stakeholder engagement
Key Weaknesses	• Regulation heavy • Key concerns unresolved	• Concepts about the development of PBR • Asset divestments required • Efficient transmission pricing is a pre-requisite • Over-reliance on a single entity	• In the case of a deep ISO, single worldview • Effective governance, grid codes and rules need to guide ISO • SO to TO contracts potentially difficult to define

Given the very strong assumptions under which the GB TSO option would work in practice as well as the fact that it requires significant asset divestments and the establishment of efficient transmission pricing, we consider that this option could not be implemented in the short to medium term.

The ISO option resolves effectively the majority of the current regime concerns. Most of the criticisms of the ISO structure can be addressed with appropriate grid codes, rules and processes. Establishing legally the ISO entity may require changes in primary legislation with associated consequences on the timetable for implementation. Although under the Status Quo+ a number of the identified concerns would remain largely unresolved, the timetable for implementation may be attractive and it could be considered to be a viable interim solution for the ISO option, given that the ISO would most likely be established through the merging of the Shadow IDA and NETSO.

It would be desirable to carry out an impact assessment for both Status Quo+ and the ISO options. The elements of the CBA[13] for each of the options are summarised in Table 3 and

Table 4.

If the estimated benefits of the Status Quo+ option are found to be marginal whereas those of the ISO are significant then the preparations for the ISO option could begin immediately, without implementing the interim solution. If, on the other hand, the Status Quo+ option benefits are also found to be significant then at the very least the Shadow IDA should be established and this would serve as an interim solution and a detailed action plan should be devised for implementing the ISO option (or potentially the TSO if efficient pricing is on the agenda).

Table 3: CBA for Status Quo + Option

Item	Comment
Status Quo + Option Implementation Costs	
Costs of establishing Shadow IDA	Experience with Brazilian IDA (Appendix C.3) could provide useful comparisons
On-going operating costs of Shadow IDA	Experience with Brazilian IDA could provide useful comparisons
Costs and barriers to implementing information transparency	Potential barriers include the increased consenting costs and monitoring costs of uncompetitive behaviours that information transparency might create
Costs of reviewing network operation and design standards to promote advanced operational measures	N/A
Status Quo + Option Implementation Benefits	
Benefits of increased co-ordination	Extension of offshore co-ordination study across regimes
Benefits of increased transmission planning and delivery efficiency	CBA based on different assumed levels of reduction in transmission investment costs
Reduction in Ofgem/DECC costs by carrying out transmission investment CBA in-house (Shadow IDA) rather than outsourcing to consultants	N/A

[13]The benefits of the Status Quo+ and the ISO option will largely depend on the assumed transmission planning and delivery efficiencies and the benefits of increased co-ordination. Given the two options' characteristics, it naturally follows that these benefits will be higher under the ISO option and this should be reflected in the impact assessment methodology that will be employed.

Table 4: CBA for ISO Option

Item	Comment
ISO Option Implementation Costs	
Loss of TO/SO Synergies in E&W	A fraction of £50mn/year[14]
Increased ISO/TO transaction costs in E&W	Estimate based on transaction costs between Scottish TOs and NETSO
One-off set up costs of ISO	Est. £100mn[15]
Consultations and code review costs	N/A
Potential ISO operational cost inefficiencies	Multiple of current NETSO annual costs
ISO Option Implementation Benefits	
Benefits of increased co-ordination	Extension of offshore co-ordination study across regimes
Benefits of increased transmission planning and delivery efficiency	CBA based on different assumed levels of reduction in transmission investment costs
Benefits of adopting advanced operational levels	CBA based on different assumed levels of reduction in system operation costs
Reduction in Ofgem costs due to reduced regulatory burden	N/A

[14]NGET estimate of cost savings due to increased operational flexibility of each company owning the assets it manages
[15]International experience [12] suggests that the set up costs of an ISO are roughly equal to one year OPEX+CAPEX. This figure is based on the RIIO-T1 NGET SO costs.

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APPENDICES

A. PRINCIPLES OF TRANSMISSION PLANNING AND DELIVERY

A.1. TRANSMISSION PLANNING IN A DEREGULATED ENVIRONMENT

The overarching objective guiding electricity system planning is to deliver and support an efficient electricity supply industry (ESI) that can provide secure, reliable and sustainable electricity system (where sustainable means meeting environmental and climate change targets). In practical terms this means that choices in transmission and generation (T&G) should minimise the Expected Net Present Value of the total system cost subject to security and environmental targets. In addition, it is desirable that the institutional design can support competition where appropriate, stimulate innovation, ensure adequate flexibility in the face of uncertainty, ensure robustness in the face of possibly changing external circumstances (to the extent this is not quite the same issue as security and reliability) and provide credibility and assurance to private investors so as to reduce their cost of capital and be able to finance the construction of both transmission and generation assets at least cost.

The Standard Market Design and Efficient Transmission Pricing

Based on our analysis of the current regimes' strengths and weaknesses, the extensive literature review conducted and the inputs received from the International Workshop, we have identified that the overarching weaknesses of the current GB transmission arrangements stem mainly from the lack of efficient transmission access pricing. Although we note that market reform is outside the scope of the ITPR project, and that projects such as EMR assume no major changes in this area, it is important to stress the key role that the short term *locational marginal pricing* combined with transmission tariffs based on the *beneficiary pays* principle, in facilitating efficient transmission operation and investment

Efficient decentralised transmission operation and planning is supported by the Standard Market Design (SMD), that involves:

- An Independent System Operator (ISO) that manages the transmission system
- Efficient short term access pricing through LMPs and financial transmission rights are in place
- Individual Transmission Owners (TOs) are responsible for availability of their assets
- ISO evaluates all proposed transmission investments using social cost benefit methodology –including reliability, economic and public policy elements
- Merchant investments are allowed subject to golden rule i.e. that the net benefits are higher than the costs
- Investments voted on by parties and go ahead if there is super-majority
- Investments tendered competitively or carried out by incumbent TOs (more details in the next section)
- Investments are then charged to the beneficiaries

As stressed short term locational marginal pricing combined with transmission tariffs based on the beneficiary pays principle are essential for facilitating coordinated, least-cost transmission and generation operation and development (planning).

Inefficiencies of GB transmission regime

In contrast, market design and network pricing in GB are inherently inefficient: given the current on-shore transmission tariffs with the majority of network costs socialised, and the fact that all balancing costs are socialised, users and are not sufficiently incentivised to make rational choices regarding the location and to constructively engage in the transmission planning and operation process to drive efficiency. In fact the present regime created perverse incentives: the lack of short term access pricing results in inefficient operation and increased network constraint costs potentially create opportunities for gaming. In 2008/2009 it was estimated that over 50% (£125mn) of the observed congestion costs were due to market power abuses. This in turn leads to transmission over-investment due to elevated observed balancing mechanism costs, which is in line with commercial interests of TSOs driven by the regulatory framework in which they operate. The absence of short-term marginal cost pricing combined with largely socialised transmission network investment costs leads to inefficient generation citing and eliminates users' incentives to (i) scrutinise network reinforcement plans and (ii) drive efficiency through implementation of cost-effective non-traditional network solutions through innovation in provision of network services. Overall, this results in inefficient transmission investment, prevents adoption of innovative non-network solutions, elevates consumer costs, leading to significant welfare losses. Again, this is in commercial interest of incumbent TSOs as increased investment in network reinforcement is an inherent objective, given the regulatory framework these companies operate within. This implies that the efficiency of the transmission planning and delivery process in GB largely depends on the TOs' incentives under RIIO, the NETSO incentives and the ability of Ofgem/DECC to scrutinise the proposed investment plans.

In addition, co-existence of merchant and regulated investment can only be effectively facilitated when efficient transmission pricing is in place. This is due to the fact that for regulated investments beneficiaries would ultimately pay for these projects. Otherwise, merchant investments would be viewed as too risky given that their revenues could be eroded if a mandated project (regulated investment) whose costs are to a large degree socialised is built. As such, there is a very high option value to wait for regulated investments to take place (and only pay a fraction of the costs) rather than sponsor merchant projects.

Lastly, with efficient transmission pricing the inconsistencies across the three regimes would be automatically be resolved and co-existence of merchant and regulated transmission investment could be facilitated. This would also imply that there would be an effective framework for the development of Multi Purpose Projects (MPPs).

Clearly, the lack of appropriate transmission pricing is against Great Britain's commitment to market led investment and efficiently operating markets. As experiences in some jurisdictions from South and North America shows, the Standard Market Design based on Locational Marginal Pricing with beneficiary pays transmission tariffs can support efficient market led transmission planning and delivery. In order to mitigate the consequences of the absence of cost reflective locational signal, Ofgem as the buyer of network service on behalf of all users and consumers, needs to ensure that the planning and delivery of network investment is as efficient as possible. This in turn requires in-depth scrutiny of investment plans that necessitates full understanding of detailed technical and economic aspects of transmission network planning and operation that is clearly beyond the remit of Ofgem's present setup.

A.2. DELIVERY

GB is characterised by three planning regimes for transmission associated with three approaches to procuring transmission assets. The offshore regime offers the prospect of competitive tendering for new assets; the onshore regime has monopoly providers of transmission service; and the international merchant regime has competitive ownership and building of assets on a price arbitrage basis. There are clearly potential inconsistencies in having three approaches. RIIO did identify the threat of competitive tendering as an important issue and suggested that, even in electricity and gas distribution there should be some threat of tendering should there be a suggestion that incumbents were not delivering assets cheaply enough. The size threshold was down to £15m projects.

Overall, competitive transmission tendering seems to have advantages especially given the difficulties in benchmarking TO costs [11]. In addition, there is significant experience across a number of jurisdictions as explained in Appendix C. On the other hand, there is a lack of conclusive evidence on the optimum structure of competitive transmission delivery auctions.

Potential benefits of competitive procurement

The theory of why auctions are a good idea is not dependent on whether the assets are in water or part of a radial or meshed network, it is about the advantages of auctions in assigning asset ownership efficiently and competing owners vs the transaction costs of the auction and the scope for gaming. The underlying asset can still have a monopoly. The National Audit Office [4] was very positive about the experience of Round 1 Offshore Transmission Auctions in the UK.

A good auction process attracts sufficient bidders, prevents collusion in bidding (especially that which might arise over time) and prevents predatory bidding (especially in early auction rounds). These features of an auction process are essential if competitive but sustainable bids are to emerge which are likely to improve on a well regulated incumbent's cost. In more complicated auction processes where there are multiple projects available to the bidders, auction processes should enhance substitution (the willingness of bidders to bid on any project), encourage price discovery (get to the right price), induce truthful bidding, be efficient in terms of letting the most suitable bidder win (a second price auction is thought to be important in achieving this) and exhibit optimality (i.e. minimise cost) [5],[6].

A worry about auction processes for large discrete assets is that the early auctions might be competitive, but over time bidders drop out and the degree of competition falls. An important discussion is what the distinction is between a public auction conducted by a third party, such as the regulator or the ISO, and the sorts of private auctions that incumbent transmission companies may routinely conduct. Private auctions have the advantage of allowing the formation of long term relationships with a panel of bidders among whom work is shared in order to maintain competition, while at the same time there may be more information sharing on cost and threat of the incumbent doing some work in house should outsourcing costs be uncompetitive. Private processes may be better at economising on transaction costs over time. These advantages arise because of flexibility in the auction rules relative to a public auction. However private auctions may miss new bidders, may lack the capacity for genuine innovation in bids and may facilitate collusion between the regulated incumbent and its suppliers to raise costs which are passed through to customers. Public processes usually strongly value the potential for new entrants. This tends to be important in conditions of cost variability and technological innovation. In short, new bidders may game public auctions but incumbents may game private ones.

There is an issue about keeping auctions competitive and about preparedness to accept that some competitively awarded assets will not appear. Competition can fail to deliver in the same way that monopolist can massively overrun on cost, time and delivery. There clearly are non-delivery risks, such as the example of the time overrun on the Ancoa-Alto Jahuel case study project in Chile [7].

A key issue to address in competitive tendering is the question of coordination with associated assets. This is particularly true of the offshore transmission regime, where there is generator concern about OFTO reliability both at the point of connection and in terms of operational regime. The separation of ownership of the OFTO from the generator does mean that the regulator needs to be careful not to stand in the way of efficient contracting for risk between the parties. The OFTO model de-risks OFTOs but increases the risk for generators, leaving a potentially suboptimal risk allocation. This suggests that incentives for timely connection and for optimal operation need to be pre-negotiated, perhaps as part of a constructive engagement process. Quality can be discussed separately within most auction processes, but there must be a mechanism to do this. The UK is in a unique position with respect to offshore assets – which are essentially spurs from generators to the main transmission grid – and would be treated as such in many jurisdictions.

The theory of auctions would seem to be extendable to more complicated package clock auctions – as used in telecoms to allocate radio spectrum - for transmission (as suggested in [8]), this could allow the competitive building, owning and operating of parts of a more complicated network design. However this requires the design of the overall network to be carefully designed in advance and the auction lots parcelled up to exploit the competitive advantages of a package clock auction. Importantly it also requires commitment to approval of multiple lines simultaneously. However in [8] it is suggested that a suitable application would be in the design of the offshore transmission network.

In [8] it is also proposed that product-mix auctions, as suggested in [6], can be applied to determine the financing period of competitively refinanced transmission assets. In these auctions bidders would supply bids on the basis of how long they wished to finance the asset for and the regulator might select a longer financing period (30 rather than 20 years) if this substantially lowered the net present value of the cost to consumers - through accessing lower cost longer-term capital.

In terms of the level of design specification for the project to be tendered the majority of tenders to date have been for very specific design specifications rather than a level of service. Nonetheless, best practice is unclear and further research would be required.

Ways forward for the UK regime

There is an issue as to whether having two approaches to asset procurement could be optimal. Clearly having one incumbent is good when there are synergies between projects and geographical advantages to a single company providing the assets via a combination of in house building and private procurement. However this decreases as the technology diverges and assets become more diverse. One *could* justify onshore and offshore simply on the grounds that offshore is point to point connection or controllable in the case of the bootstrap and large scale, while onshore is more diverse and requires more local knowledge, especially around interconnection with existing transmission system.

However a more obvious driver of two regimes is the cost of procurement. This becomes prohibitive below a certain size of asset and also the time delay – given that public procurement takes longer - becomes onerous. Clearly having an agreed plan or triggers and floors around time critical assets may be helpful, rather than having a lengthy public procurement process – as opposed to a private procurement process.

There may be other bases for having multiple regimes – e.g. DC vs AC, number of interconnecting nodes etc. However it is not clear that there is an economic case to be made for anything other than a financial size threshold.

Sorting out the current regime boundaries would seem to require reducing the scope for gaming across the different regimes – as was a concern in the Western Bootstrap where an offshore merchant type project was justified as an incumbent build project. In terms of preventing gaming across regimes, the obvious thing is to have a size threshold. This is in use elsewhere, e.g. in Chile (see section in Chile below). Everything above a certain size would automatically be auctioned. The inconsistency of the current regime is that only assets deemed to be offshore are auctioned automatically, as the Western Bootstrap illustrates.

It is also important to emphasise that competitive procurement is not just about new assets, or more particularly more lines. It could be about packages of upgrade works to existing assets (it seems to be about this in Chile and Argentina). This is especially important in the onshore transmission system in the UK where one might expect that stretching the capability of existing assets is significant and might involve the application of new and innovative technologies.

As the following section elaborates, there is lots of competition in the provision of transmission assets internationally. We have many examples of 'competitive' (i.e. non-incumbent provided) projects in Texas, California, PJM etc as well in Chile, Argentina and Brazil, not to mention in the UK for offshore transmission. In [9] regulated merchant and pure merchant projects in the US are distinguished, with regulated merchant being those with some regulatory guarantees around the project, while pure merchant projects exploit price arbitrage opportunities. Among the many significant merchant projects in the US are MATL, Champlain Hudson Power Express, Southwest-Midwest projects and Tres Amigas. ISOs/RTOs in the US offer the possibility of clear separation of transmission planning and value assessment and asset procurement. The current merging of transmission asset ownership and planning in GB would seem to be a problem to unlock synergies and to bring regimes on and offshore into line in the UK.

FERC Order 1000 suggests that incumbents cannot have right of first refusal on new transmission lines, suggesting that a more general move to competitive procurement of transmission is favoured in the US. This is mostly not on a pure merchant basis, though there are some interesting merchant transmission links across and between RTO regions. Also ISOs/RTOs still commission lots of reliability investments on an incumbent build basis – though this would appear to be because the right to build lines within particular areas within certain states still rests with a single company (see section below on PJM).

Competition in the provision of transmission assets can be for quite small packages of assets. Competition is important in producing innovation on costs and in reducing regulation cost. In [10] this is discussed in the context of the Buenos Aires province case. Below a certain size, packages are a possibility to reach the size threshold for auctioning. This would also be true for specific regimes for maintenance. The Chilean regime is particularly appealing because it suggests having a fixed mark up (15%) on winning bids for smaller lots and putting this in the regulatory asset base.

Implications of more use of tendering

There is an issue about preserving past RAV and the link between operating and capital efficiency. We need to think about moving to a Performance Based Ratemaking (PBR) type approach with dead-banding. Traditional efficiency measurement is increasingly becoming an ineffective as a basis for regulation [11].

Separation of ISO and TOs is much more desirable, as the Offshore Regime is beginning to show. This would hasten the day of separation of asset ownership from system operation. There is also the question of who oversees the tendering process. It is not desirable that this is the regulator as this would seem to reduce the scope for innovation and self-governance of the industry. It would be desirable to have a private entity, in the shape of an ISO, to oversee the process and make commercial judgements about how it is working. An ISO would have an incentive to have regard to overall tender system costs.

There are legitimate worries about tendering in terms of financial costs and guarantees. Is like being compared with like? Incumbent grid companies might claim that tax shield and specific asset guarantees have brought financial players in to offshore on unfair terms. The UK Public Accounts Committee was particularly critical on this point. As such it would be important that there was proper oversight of the tax position of SPVs established to build, own and operate transmission assets.

B. CURRENT REGIME STRENGTH AND WEAKNESSES

Onshore regime

The GB onshore transmission network is planned by the three onshore licensees or transmission owners (TO), i.e. National Grid, Scottish Hydro Electricity Transmission plc and Scottish Power Transmission Limited, in coordination with the National Electricity Transmission System Operator (NETSO –National Grid–) responsible for GB system operation and access to the onshore network. The System Operator-Transmission Owner Code (STC) defines the high-level relationship between the NETSO and Transmission Owners. TOs' revenues are subject to the Price Control that provides framework for network investment. In addition to the allowed revenue defined according to a baseline investment, approved by Ofgem at the beginning of the control period, a number of uncertainty mechanisms are in place in order to deal with uncertainty over the 8 year period of the price control. Additional strategic wider works (SWW) can be triggered within the control period according to the actual volume of connections.

As discussed throughout the report, GB market design and network pricing regime will lead to inefficient network operation and investment, adoption of asset heavy rather than innovative cost effective non-network solutions, elevate consumer costs leading to significant welfare losses. In order to mitigate the consequences of the absence of cost reflective locational signal, Ofgem/DECC as the buyer of network service on behalf of all users and consumers, needs to ensure that the planning and delivery of network investment is as efficient as possible. This in turn requires in-depth scrutiny of investment plans and it is highly questionable whether Ofgem/DECC possess the expertise needed to increasingly act as the single buyer of onshore and offshore network services, as the complexity and interactions between these will significantly increase.

There are however important strengths of the present GB regime given the integrated TO and SO functions (at least in England&Wales). This, in principle, enables the development of a holistic approach for planning, delivery and operation of the transmission network, where the short term costs of network operation can be balanced with long-term asset costs. Clearly, this joint operation and ownership of network infrastructure can minimise the interface and transaction costs between the network planning, delivery and operability of network assets. In the particular case of England and Wales, where National Grid acts as both NETSO and TO there is evidence[16] of benefits from coordination of short term network operation and long-term asset management activities. On the other hand NGET has experienced difficulties in codifying reasonable performance/risk trade-offs in the SO TO Code (Scottish TOs initially unwilling to provide cyclic / short-term asset ratings). The materiality of reducing system operator effectiveness by reducing information exchanges with asset managers may approach £50m/yr, which may increase further as wind penetration and other 'connect and manage' impacts grow.

Furthermore, there have benefits through exposure to the system operator's balancing services incentive scheme (BSIS). Such exposure has driven a number of asset owner innovations:

- NGET introduced live line working on high voltage overhead lines and options for enhanced weekend/shift working to reduce the number of network access outages and their durations.
- Temporary line facilities were developed to enable bypass circuits to reduce critical outages.

[16] *Provided through discussions with National Grid*

- Flexible/re-locatable voltage support equipment was developed to reduce constraint exposures following power stations closure announcements.
- New conductor systems were introduced with a range of capability/capital cost/lifetime cost trade-offs. (For example, GAP high capacity conductors, AAAC low loss conductors, triple conductor reduced impedance enhanced capacity bundles). Also risk based assessments of hot-wire opportunities have also been implemented.
- NGET led on the development of transmission network output measures to ensure asset stewardship is aligned with the delivery of the overall network service.
- Work by-passes for equipment issues that can lead to hazardous catastrophic failure have been developed to ensure system operator customer connection and system constraint issues are minimised.
- NGET's plans on strategic asset management aim to ensure transmission asset health information is available for minimising the lifetime cost of asset management but also to deliver best value in terms of the overall network service.

In case of separation of SO and TO functions, it will be important to ensure that these strengths are maintained through appropriate governance regimes.

The above is summarised in Table 5- Table 7 together with other identified strengths and weaknesses of the onshore regime.

Table 5: Onshore Transmission Planning Strength and Weaknesses

Strengths	*Weaknesses*
• Reactive investment minimizing the risk of stranded assets • TOs' investment plans partially coordinated through NETSO and ENSG • Holistic short and long-term cost minimisation in England & Wales through optimising the entire transmission cost function of investment and operation (assuming efficient incentives) taking advantage of the TO/SO synergies • Planning process is faster as it does not depend on decisions, agreements or negotiations between multiple parties • Fully coordinated central plan within each licensee's area to minimise costs and maintain reliability • There exists a framework to deal with uncertainty and anticipatory investment	• Investment proposed by TOs cannot be scrutinised technically, leaving economic efficiency of proposed investments depending primarily on incentives to TOs. • Balancing mechanism design (pay-as-bid) does not allow TOs to extract the correct price signals for network planning, potentially leading to overinvestment. • Current regulatory framework does not allow TSO to balance operation and planning costs with users' reliability benefits, potentially incentivising asset-heavy solutions against cost-effective operational measures. • TSO can arbitrage between planning and operational activities, depending on incentives • Insufficient coordination with smaller

(SWW) based on trigger events (albeit its efficiency is not clear yet) • There exists a public modelling tool (Scenario Illustrator) that enables high level cost benefit assessment of investments to communicate stakeholders • Access is coordinated through NETSO • TNUOS reflects (to some extent) locational LRMC of wider infrastructure	TOs (interconnectors and offshore) mainly through bilateral agreement for connection • Not clear if locational component of TNUOS to which generation is exposed, is sufficient to foster efficient location of new generation

Table 6: Onshore Transmission Delivery Strength and Weaknesses

Strengths	*Weaknesses*
• Holistic management of the delivery (construction) within each licensee's. • Low complexity and timely delivery. • Revenue stream based also on incentives over outputs (RIIO)	• Revenue stream also based on actual expenditure with ex-post reviews (risk to accept inefficient costs as efficient due to lack of information, i.e. agency costs) • No contestability and therefore comparison between multiple delivery solutions

Table 7: Onshore Transmission Operation Strength and Weaknesses

Strengths	*Weaknesses*
• Holistic view by NETSO to coordinate the operation in England and Wales.	• No sufficiently coordinated maintenance plans between TOs in Scotland and NETSO • No exposure of TOs in Scotland to balancing costs • NETSO exposed to penalties for inefficient maintenance schedules of other TOs • NGET can arbitrage between its planning and operational activities, depending on the incentive mechanisms in place

Offshore regime

The GB offshore transmission network is planned following a market-led approach, where generators propose the high level designs and NETSO administrates access to the onshore grid. In this process, TOs interacts with NETSO to propose construction offers related to the onshore network enhancements needed to accommodate the new offshore connection. Although there is no formal or mandated framework for coordination of multiple offshore generators, NETSO can potentially do so through a voluntary interactive queue scheme. However, all offshore-to-onshore connections so far (i.e. in Round 1 and 2) have been fundamentally radial, fitting specific needs of a particular generator.

Under the enduring regime, there are two possible arrangements for offshore transmission that can be chosen by generation, namely generator build and OFTO (offshore transmission owner) build, which are mainly differentiated by the responsibilities of generation in the construction process. Under generator build, generator's responsibilities include design, pre-construction and construction of the offshore network, while under OFTO build generator's responsibilities include only the design and pre-construction. In both, the OFTO that operates and maintains the offshore assets (and potentially constructs them) is the winner of a competitive tender organised and run by Ofgem where bidders offer a 20-year revenue stream.

The offshore regime above permits to have solutions tailored to users' need, minimising the risk of asset stranding. Also, coordination benefits can be fully captured by offshore developers, since any savings in network capex will directly affect the Transmission Network Use of System (TNUoS) charges that generators will pay to transmission owners. This supports the approach to have a market-based coordination. However, under a merely market-led approach leading developers may have an incentive to deter entry of other developers as observed in other countries with similar regimes (e.g. Argentina, Chile). There is also an increased cost associated with the development of the overall offshore network due to a piecemeal expansion of it, that does not considers the benefits associated with economies of scale and anticipatory/strategic investment. This also increases the environmental impact of new connection. Furthermore, there are 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 (or even not to have assets delivered such as cases in Peru), that may need to be borne ultimately by consumers.

The above is summarised in Table 8 - Table 10 together with other identified strengths and weaknesses of the offshore regime.

Table 8: Offshore Transmission Planning Strength and Weaknesses

Strengths	*Weaknesses*
• Reactive planning based on demonstrable need and market conditions, with no risk of asset stranding. • Offshore grid co-ordination benefits are fully captured by offshore developers, giving an appropriate incentive for constructive engagement between offshore developers with regards to planning offshore network assets (no need for mandated anticipatory investment). • Developer can accept/reject NETSO connection proposals → Solutions tailored to the user's need.	• Costs of onshore substation works are socialized, giving no incentive to the developer for offshore-onshore coordination. • NETSO decides on onshore landing point, with a potentially perverse incentive to favour solutions involving extended onshore upgrades. • Coordinated planning may be hindered by business confidentiality issues between: ➢ Prospective offshore developers ➢ Onshore TOs • Leading developers may have incentive to deter entry of other developers (e.g. in order to reduce competition for future subsidy allocation). • Risk of piecemeal/incremental network development. • No incentive for developers to accept designs involving wider benefit anticipatory elements.

Table 9: Offshore Transmission Delivery Strength and Weaknesses

Strengths	*Weaknesses*
• Efficient financing - Market-based delivery has been shown to secure funding with lower cost of capital. Specific to Generator Build: • Appropriate incentive for CAPEX efficiency (optimising cost and quality) since generators ultimately fund assets and are directly exposed to asset availability. • Competitive pressure drives cost efficiencies in funding and O&M solutions	Specific to Generator Build: • Onshore substation is not part of offshore TNUoS local asset charges → no incentive for cost-efficient onshore delivery. Specific to OFTO Build: • Risk of non-delivery/delays due to auction winner's curse. • Increased complexity and cost of the tendering process may pose barriers to entry.

Specific to OFTO Build: • Competitive tender pressure drives cost-efficient offshore & onshore delivery. • Increased scope for innovation in the delivery process. • OFTO's revenue exposure to link availability and construction delays incentivizes quality and timely delivery.	• Reduced incentive to deliver assets with lifetimes beyond 20 years.

Table 10: Offshore Transmission Operation Strength and Weaknesses

Strengths	*Weaknesses*
• The link availability incentive drives efficient OPEX. • Increased scope for innovative and efficient operational solutions due to OFTO's expertise and maintenance services aggregation (scale economies).	• Current availability incentive does not directly incentivise maintenance coordination for export maximization. • Availability incentive does not differentiate between planned and unplanned outages. • OFTO's penalty capped at 50% of TRS over 5 years, while developer is fully exposed to outage events with no compensation (albeit percentage of revenue at risk for OFTO is larger (by c. 2.5 times) than for generator). • Reduced incentive for inter-OFTO maintenance co-ordination in the case of multi-zonal projects that involve shared assets. • No incentive to undertake maintenance solutions that will prolong the asset's lifetime beyond the contracted 20 years.

Interconnector regime

Interconnectors are planned following a market-led approach, where network developers propose design, deliver and operate interconnectors and NETSO administrates access to the onshore grid by proposing construction offers related to the onshore network enhancements needed to accommodate the new connection. There are two types of arrangements, namely merchant and combined merchant / regulated discussed more recently, differentiated by the presence of a cap and floor revenue associated with the latter. In the former, therefore, upside and downside risks are borne by the interconnector owners. In both, developers identify capacity, locations and assets to be built, and costs of operation, planning and delivery are recovered through rents based on network congestion (i.e. tender of capacity or market coupling price differences). Thus, under the interconnector regime main decisions related to the planning process depend on developers and potentially on TOs at both countries that can share some of the risks associated with the interconnector business. Main decisions in the delivery process would depend only on developers.

The interconnector regime above permits to have in principle high levels of efficiency in both planning and delivery since associated costs are borne entirely by owners. This is not only true for capex, but also for opex, given that revenue streams would depend merely on congestion, regardless of expenditure. However, theoretical evidence shows that the exposure to congestion-only revenue leads to undermine the value of network capacity. Lack of coordination between the different projects can also drive suboptimal results regarding the overall network capacity and the role of NETSO in coordination might deter third party entrants and competition. Additionally, interconnectors do not face access charges associated with the onshore infrastructure, which may drive inefficient onshore reinforcement costs due to a suboptimal landing point that can also create perverse incentives for NETSO's construction offers. Furthermore, it has been reported that there is a lack of response in the transfers of the interconnectors compared with the dynamic changes in the operation of the onshore network, leading to increased cost of constraints.

The above is summarised in Table 11 - Table 13 together with other identified strengths and weaknesses of the interconnector regime.

Table 11: Interconnector Transmission Planning Strength and Weaknesses

Strengths	*Weaknesses*
• Market led in theory, project sponsor has incentives for efficient technical planning.	• Overall level of interconnection is likely to be suboptimal given the lack co-ordinated efforts for development • Planning process is not formalised • There is potential conflict of interest from the part of the NETSO which might deter 3rd part entrants and competition • Interconnectors do not face any access pricing signals on where to connect to the onshore system thus no co-ordination between onshore and interconnectors • NETSO when offering connection options to interconnectors does not seem to be doing it in a coordinated manner and does not seem to have considered what is economic and efficient • For regulated approach depending on cap & colar these incentives might be very small

Table 12: Interconnector Transmission Delivery Strength and Weaknesses

Strengths	*Weaknesses*
• For both merchant and regulatory interconnectors revenue is based mainly on price differentials so there are strong incentives for efficient CAPEX	• For regulated approach depending on cap & collar these incentives might be very small

Table 13: Interconnector Transmission Operation Strength and Weaknesses

Strengths	*Weaknesses*
• For both merchant and regulatory interconnectors revenue is based mainly on price differentials so there are strong incentives for efficient OPEX	• No consistency on the firmness of access that different interconnectors receive and offer to TRs holders • Operation of interconnectors is carried out by IC owners not NETSO so their operation is not co-optimised with onshore system • For regulated approach depending on cap & collar these incentives can be marginal • NETSO so as to provide firm access to interconnectors, under the new SO incentives, will not be incentivised on efficient short term constraint management

C. TRANSMISSION PLANNING AND DELIVERY INTERNATIONAL PRACTICE

C.1. ARGENTINA

Overview

The Argentinian transmission planning process has been very well documented in a series of papers by S.Littlechild [9], [11]-[16].

The transmission planning process introduced as part of the electricity sector reforms of 1992 was based on the Public Contest Method. As elaborated in [14], 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.

The prevailing view is that the electricity reforms, with respect to transmission expansion, have been a remarkable success. However, 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. However, recent research has put to question the validity of these concerns.

The overarching aim of the Argentinian electricity market reform was to create competition to provide the services, as far as possible independent of regulation and government involvement. The challenge was to achieve competition in transmission, which was generally held to be a monopoly, while retaining the technical unity of the transmission system as a whole.

There were several key steps in the thinking. These were the recognition:

- that the existing transmission system was not homogeneous, but already included various elements in different ownership and operation;
- that the extent of effective capacity in the system as a whole depended not only on the availability of generation stations and transmission lines, but also and more importantly on the control and dispatch of the system;
- that such control and dispatch could be separated from the ownership and management of the transmission lines;
- that the existing transmission facilities could sensibly be split into several different systems at different voltages;
- that over time entry and growth of other transmission companies could be envisaged;
- and, crucially, that new facilities could be regulated separately and differently from existing ones.
- The initial results of this thinking were the creation of:
    - an extra-high voltage (500 kV) national transmission system, known as Transener,
    - five separate high voltage (132 kV) regional sub-transmission systems, and
    - an Independent System Operator (ISO) called CAMMESA, separate from the transmission companies.

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, and they had a valuable role to play in enabling the arrangements to run smoothly without unnecessary cost.

Planning

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. The Dispatch Organisation (part of CAMMESA) carries out a technical study, using the so-called 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 amortisation.

The proponents must represent at least 30% of the beneficiaries that the expansion would bring in its "area of influence". ENRE (the regulator) 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 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'(called a canon) over an amortisation period approved by ENRE. The duration of the amortisation period was limited.

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 actual 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.

Epigrammatically and as summarised in [17] the Argentinian transmission planning 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).

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:

• A requester group (generators, distributors or large customers) who want a new line to be built, request authorization to do so from the transmission firm to which they connect. The request describes the project and indicates either (i) a maximum annual fee, such that if nobody bids lower, 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: (i) 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 below0 the maximum fee, the auction is declared void and the process terminates; (ii) 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.

These are expansions or adaptations of existing transformer stations owned by an operator or an independent transmission firm, which do not form part of an expansion reaching beyond the transformer station.

In such case, a transmission firm wishing to expand its installations must submit a budget for the civil works and an annual fee proposal, together with the request for a certificate of convenience and necessity. ENRE will process the request if it considers that the technical, economic, reliability, safety, and transmission capacity studies submitted by the requester justify the expansion; and it accepts the operating and maintenance costs declared by the requester. These may not exceed regulated values for the existing installations. Once this has been satisfied, ENRE authorizes the requester to convene an auction process.

In expansions requested by the operator or the independent transmission firm that owns the station, the inspection of the civil works will be carried out by the owner of the station for the fee quoted by it, provided this is duly justified and supported in an adequate declaration of costs, to the satisfaction of ENRE, with supervision charges included in this amount. If none of the bids received for engineering, supply and assembly are better than the fee budgeted by the requester that owns the station, ENRE will declare the auction void, thereby automatically revoking the CCN previously issued.

Assessment

The Argentina approach was successful in driving significant transmission investment; over the period 1993 to 2003 the length of transmission lines increased by 20 per cent, main transformers by 21 per cent, compensators by 27 per cent and substations by 37 per cent, whereas series capacitors increased by 176 per cent. As a result, transmission capacity limits increased by 105 per cent, more than sufficient to meet the increase in system demand of over 50 per cent. Overall, Littlechild argues that this method designed to aggregate stakeholder preferences to make choices about major transmission investments was remarkably successful.

As Hogan [17] mentions, the Argentine experience showcases that:

- transmission investment could be compatible with Standard Market Design (Co-ordinated sport market with LMPs and independent ISO) incentives;
- beneficiaries could be defined;
- participant funding could support a market.

With respect to competitive delivery, [13] presents a positive analysis of this approach in Argentina. He argues that 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, in [13] it is argued that there were adequate numbers of bidders for the expansions, ranging from 1 to 7 with median 3. In the few (3) cases of only one bidder, there was no evidence of ability to exploit that position. 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. Competition brought down by about half the costs of building and operating new lines. In contrast, costs under the present Federal Transmission Plan have increased to two and a half times the level under the Public Contest approach.

On the other hand, there have been criticisms that the Public Contest method, with the accompanying Area of Influence cost recovery methodology is not replicable in meshed networks. However, this assertion has been challenged in [9].

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

- Increasing 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 Argentine 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, which could offer state of the art solutions.

C.2. AUSTRALIA

Overview

The Australian National Electricity Market (NEM) enables the trading of electricity throughout Australia, excepting Western Australia and the Northern (Figure 6).

The responsibility for energy policy rests with the Standing Council on Energy and Resources (SCER), a recently formed Council of Australian Government standing council, which has assumed the functions of the Ministerial Council on Energy (MCE).

The responsibility for making Rule changes rests with the Australian Energy Market Commission (AEMC), an independent national body funded by all state and territory governments The AEMC has a strictly limited independent capacity to initiate Rule changes, and responds to requests by other parties, such as the ministerial council, the regulator and end-users.

The regulator, the AER, is an independent Australian Government statutory authority. Its main role is the determination of price limits and revenue caps, although it also ensures business compliance with regulations, and collects information on the energy market.

The Australian Energy Market Operator (AEMO) is also an important part of the institutional arrangements for electricity (and natural gas). It is structured as a corporation with a skill-based board comprising government and private members. Its electricity responsibilities include managing the electricity market and playing a coordinating role in ensuring system security when demand exceeds supply. It takes bids and determines spot prices for generators, and ensures demand and supply are matched. AEMO also provides long-term planning reports and regional demand forecasts, and directly manages the planning of the Victorian electricity transmission system to ensure existing and expected demands are met. In other jurisdictions, the state government or asset owners undertake these functions.

State and territory governments and their regulators play a major role in regulating reliability standards and retailing in the NEM. State and territory governments also have various renewable energy policies that affect network businesses' options for addressing emerging bottlenecks in their systems. They are the owners of network services in Queensland, New South Wales, Tasmania and, in part, the ACT (and also own generators).

There is no uniform regulation of network services in the NEM, with major variations in the treatment of:

- the intra-regional transmission network, which comprises the high voltage components of the network that carry power over long distances within states
- the high-voltage transmission network ('interconnectors') used to transport power between states (Figure 6)
- the distribution network, the lower voltage capillaries that deliver power at the local level. The distribution network accounts for the bulk of the infrastructure and costs. The distinction between lines and assets characterised as belonging to the distribution and transmission network varies between jurisdictions.

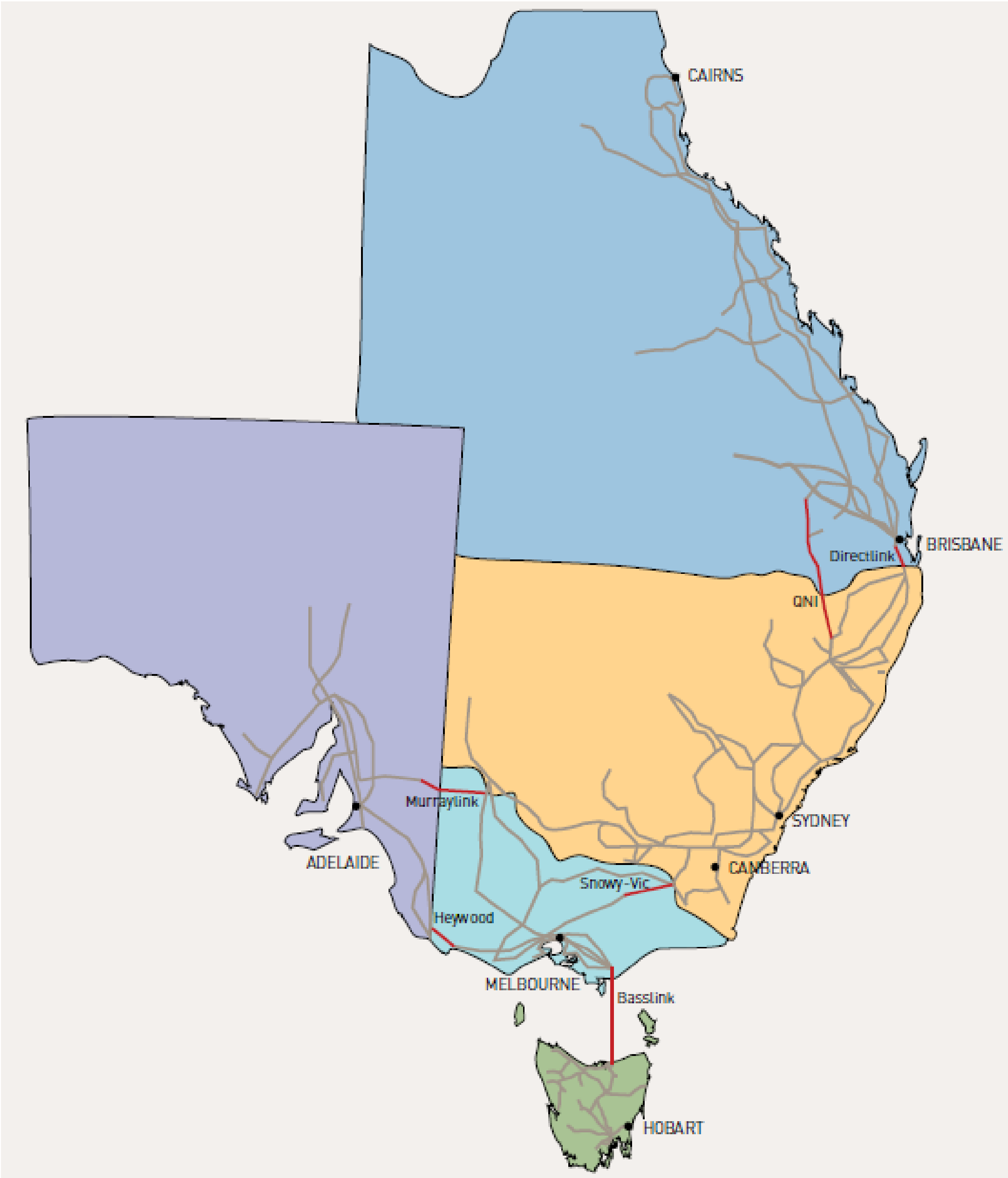

Figure 6: The NEM Transmission Network

Planning

The planning on transmission networks in each region of the NEM is undertaken by the local transmission network business, with the exception of Victoria, where AEMO performs this role instead of the TNSP.

The planners are required to publish Annual Planning Reports (APRs) which contain detailed analysis of the planned transmission network over a five year horizon. The APRs are not developed in isolation, and are required to take into account the National Transmission Network Development Plan (NTNDP), prepared annually by AEMO.

Strictly, this only requires that the TNSPs publicly describe the extent of any deviation from the NTNDP, bringing (a degree of) transparency to the interaction between jurisdictional and NEM-wide planning.

In preparing the plans, each TNSP is required to conduct an annual planning review with distribution companies connected to their network. This review must 'take into account' the NTNDP (failure to do so incurs a financial penalty). Importantly, while TNSPs are obliged to consider the NTNDP, the final decision for planning matters rests with each individual network service provider.

In its role as the National Transmission Planner, AEMO annually publishes the NTNDP. In contrast to the detailed, local planning, of the APRs, the NTNDP is intended to provide a 'strategic' and national outlook, over a 20 year horizon.

Mirroring the requirements on TNSPs, in preparing the NTNDP, AEMO must 'have regard to', among others things, the most recent APRs, as well as the revenue determinations for the TNSPs. This repeated cross-referencing of the APRs and the NTNDP is intended to provide a transparent 'feedback loop' which should, in theory, iterate towards alignment between the levels of planning. However, the NTNDP is not determinative. AEMO cannot direct a TNSP (except in Victoria) to undertake a given investment detailed in the plan. Instead, its role is to bring an alternative (long-term) focus and inform the market about potential development options, at best influencing investment outcomes (outside Victoria).

These arrangements are new. The first interim national statement (a precursor to the NTNDP) was published by AEMO at the end of 2009, and the first comprehensive NTNDP was published at the end of 2010.

As set out in [18] the Regulatory Investment Test for Transmission (RIT-T) is a cost benefit process that is done before all major new transmission projects, including interconnectors, are undertaken. It is not required if a transmission asset is being replaced, rather than augmented. In attempting to replicate investment outcomes that would arise in a competitive market environment, the RIT-T aims to quantify the costs and benefits that accrue to those who consume, transport or generate electricity as the result of a new project; and to ensure that only projects with the highest net present value proceed. In doing so, it includes several categories of costs and benefits.

The RIT-T process is relatively simple, at least in principle. For any proposed new investment, the party performing the test compiles a list of options. These options can be network options, or they could be alternatives such as demand management or a new generator. At this stage of the process, interested parties are allowed to raise alternatives that must be considered or a rationale given for their exclusion.

Once a list of options is finalised, the expected benefit of each project is calculated using the costs and benefit categories described in the RIT-T documentation. The costs that can be included are:

- the costs of construction or providing the options
- operating and maintenance costs
- cost of complying with laws and regulations
- any other reasonable costs that are agreed to by the AER.

The benefits considered under the RIT-T include:

- decreased fuel dispatch

• reductions in voluntary load curtailment (when electricity users will reduce

consumption for a price)

• reductions in involuntary load shedding (when electricity supply is cut off to parts of

the network to maintain system security)

• changes in cost to other parties, such as the deferral of a new plant

• differences in the timing of other transmission projects

• changes in network losses or in ancillary services costs

• competition benefits

• option value (the benefit from retaining flexibility by taking a sunk action, such as reserving property rights, whose value could change in the future)

• adjustments for helping to meet the Renewable Energy Target

These costs and benefits are calculated in a number of forecast scenarios, and assigned a weight for the probability that each state will occur. The project with the highest, probability weighted, net present value is chosen by the TNSP for development. Throughout the application of the RIT-T, the regulator only plays a role in monitoring issues of process, such as not following the consultation guidelines, and plays no active role in approving the RIT-T outcomes.

The RIT-T currently only applies to network augmentations where the cost of any option considered is over $5 million. This excludes smaller projects as well as the replacement of existing assets.

Delivery

In Victoria, AEMO is the responsible not-for-profit transmission planner, procurer of the transmission network and provider of transmission services to users. Candidate projects are subjected to the RIT-T and if the result is positive, the building assessment proceeds. Competitive tendering provisions are in place for investments where the capital costs are expected to exceed $10 million and can be provided separately by another party (without affecting assets of the incumbent TO AusNet).

AEMO produces the documents such that it requests an asset owner to provide a level of service rather than defined assets. In this way tenderers are encouraged to be innovative in their solutions and it facilitates greater responses from demand side and generation solutions [19].

SP AusNet [23] has commented on the complexity of the connection process in Victoria. This involves tri-partite negotiation of contractual arrangements to define the arrangements for service provision. The connection applicant has service contracts with both AEMO and SP AusNet, and contracting is also required between AEMO and SP AusNet. For one new generation connection, mapping of the arrangements reveals 23 executed documents.

The direct impact is an extensive period required to reach agreement on the terms of connection, and the very high legal cost accruing to parties. As the costs can be so high, AEMO's legal costs are typically met by the connection applicant [23].

In consultations with market participants, experiences in Victoria are largely negative [20]. Connection applicants find that negotiating with AEMO creates an extra step in the process which leads to significant delays and that the need for tripartite agreements creates substantial inefficiency in the process [20].

Grid Australia [21] (the industry body of the incumbent TOs) claims that AEMO's reliance on the competitive process essentially imposes no scrutiny on whether expenditure proposals are efficient. It also suggests that there is no evidence that Victoria's competitive tendering model has reduced costs compared to regulated regimes and no independent study has taken place. Victoria has had a historical excess of capacity and thus the competitive regime has not been put to test. There are suspicions that increased tendering/transaction costs have worked in the opposite direction [21].

On the other hand, AEMO has provided evidence on a confidential basis [24] that the competitive tendering process in Victoria is positive although recognising that the tendering process can be improved.

In the rest of Australia, stakeholders have indicated that limited transparency exists on the underlying costs of transmission connection services incurred by the TNSP. Users want reassurance that the cheapest alternative has been chosen by the TNSP. Although TNSPs do auction off the actual construction (and sometimes the design) to independent service providers, it is not clear that the competition benefits are shared with connection applicants.

Assessment

AEMC (Energy Market Commission) has launched a consultation process to identify room for improvement in the network business. The Electricity Network Regulation public inquiry final report was submitted to the government on the 9th of April, 2013 and at the time of writing it was not publicly available. Based on the draft report recommendations, the following were put forward:

- enhancing the Australian Energy Market Operator's (AEMO's) role as a developer of national plans, and in oversight of various planning reports and regulatory investment tests produced by Transmission Network Service Providers (TNSPs);
- aligning regulatory control periods;
- making AEMO responsible for the determination of transmission use of system tariffs; and
- ending AEMO's role as procurer of transmission expansion in Victoria i.e. eliminating the tendering process and in effect harmonizing Victoria planning and delivery with the rest of the states.

In practice, as noted in [25] the AEMC's proposals still leaves AEMO simply as an advisor to the TNSPs, a role which TNSPs are unlikely to embrace. This is because AEMO will have no executive authority to ensure that network developments follow their plans.

With respect to the changes in Victoria, the essence of the AEMC's argument for this change is that the Victorian model has not delivered competitive tenders because SP Ausnet has won almost all the tenders issued by AEMO.

However, in [25] whilst recognising the significant scope for improvement of the tendering process in Victoria, compelling evidence are put forward of the significantly more efficient transmission planning process in Victoria as opposed to the other states that have experienced similar load growths. In particular, it is suggested that Victoria achieves the same levels of service and reliability as the other states, but pays less. This seems to be driven by the fact that AEMO plans the system in Victoria rather than the incumbent TO, which earns a RAV revenue (as well as serving other regional interests) and has inherent conflicts of interest to overstate investment needs.

This is a particularly important lesson for GB, as it suggests that in the case of Australia, ISO driven (AEMO) transmission planning is more efficient than incumbent TO irrespective of whether there is (efficient) competitive delivery or not.

C.3. BRAZIL

Overview

The Brazilian electricity system is the largest in Latin America with a peak demand of 70 GW and a generation fleet circa 106 GW. Brazil boasts one of the world's cleanest energy mixes with 85% of energy production derived from renewable sources, primarily hydropower. In recent years, the renewables portfolio has expanded even further with significant additions of biomass and wind energy. Brazil is experiencing an average consumption growth rate of 4.6% per year and a similar peak growth rate. Over the period 2011-2020, the government estimates that over 30,000km of AC circuit and 10,000km of DC circuit will have to be built to meet the country's growing energy demand [26].

Planning

In Brazil, transmission expansion is driven by an auction-based system where capacity auctions are help on an annual basis, where long-term contracts are offered for new capacity to be commissioned. There are two types of auctions; main and complementary. In the main auctions, the capacity being procured must be provided within five years, whereas complementary auctions are targeted towards smaller plants to be commissioned within three years. The target energy to be contracted is defined on the basis of distribution companies' load forecasts. In these auctions, all conventional generation technologies compete together to determine the developers that can deliver capacity most economically. Auction winners sign bilateral supply contracts with their respective distribution company. In order to inform their bids, developers participating in the capacity auctions are given preliminary economic signals (calculated using a long-run marginal cost methodology [27]) regarding the transport tariffs they would face. Overall, from 2004 to 2010, Brazil has carried out 21 such contract auctions, resulting in financial transactions of about $300billion [28] total energy value.

It is only after the location, size and type of new units has been determined that the formal transmission planning process can take place. This way, transmission expansion can be carried out against a certain generation background. Brazil's transmission expansion plan is centrally planned by Empresa de Pesquisa Energetica (EPE is a state-owned research and planning company) each year. An annual plan is proposed to cover transmission service needs over the next five years. The plan is identified through a minimum-cost security-constrained optimization algorithm and is subject to a public hearing process. The final approval is granted by the Ministry of Mines and Energy (MME). Once approved, reinforcements are auctioned for delivery. Prior to the auctions, the regulator ANEEL (Agencia Nacional de Energia Electrica) performs studies on all approved projects and sets the opening (maximum) bids according to reference costs from a publicly-available database. This is done to ensure that the cost-benefit ratio of procured solutions is consistent with the undertaken analysis.

Transmission for non-conventional renewable energy plants (all renewables except large hydro installations) follows a separate expansion process. Over the last years, Brazil has experienced hundreds of small candidate biomass and wind projects, spread over a wide area. For example, Generally, the challenge of connecting a large number of renewable sources spread-out over a large area is very different to planning dedicated links for large hydrothermal plants. Firstly, the large number of small candidate plants results in a very high planning workload; distribution company planning teams have insufficient resources to tackle this matter. Secondly, uncertainty surrounds which of the prospective plants will indeed go ahead and be constructed. Naturally, the short construction times of medium-scale renewables exacerbate this problem by leaving little room for adjust investment plans to any new information. Thirdly, there exist significant opportunities for economies of scale through design optimization at both the connection level and system reinforcement. There is a large scope for coordinating the build-out of shared connection facilities, especially with respect to the number and siting of collector and sub-collector stations. For these reasons, candidate renewable plants are subject to a different planning process, adapted to address the aforementioned issues.

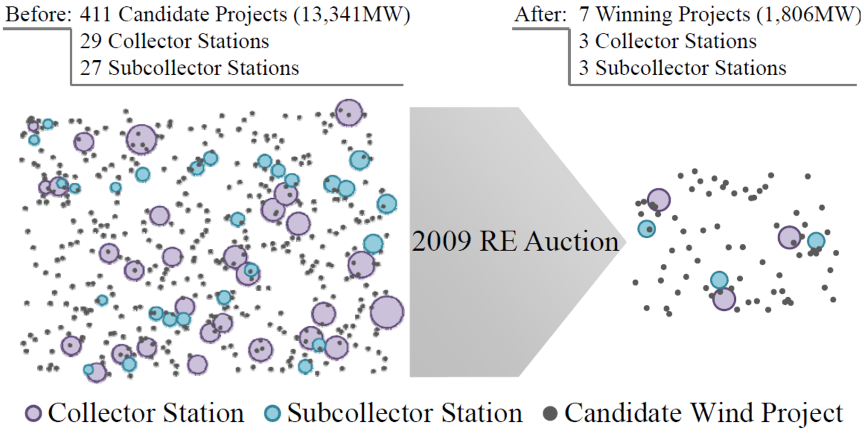

Figure 7: Illustrative comparison of number of candidate (left) and winning projects (right) participating in the 2009 NCRE energy auction [39]

The NCRE planning process was introduced in 2008 and can be summarized as follows. Developers interested in building a renewable generation plant in a region prepare a technical plan to be approved initially by EPE and then by ANEEL, ensuring regulatory compliance (e.g. successful environmental surveys etc). This ‘decentralized’ approach relieves the managerial strain of securing numerous wayleaves and environmental permits, essentially rendering the developers liable for their own routing choices. Once approved, the developer must compete in the NCRE energy auction market and win an energy contract with a supplier. Note that in order to provide developers with an idea of the connection charges they will be likely facing, EPE can provide each plant with some non-binding estimates. Through these annual energy auctions, winners confirm their transmission service needs by showcasing the economic viability and attractiveness of their project and locking in long-term revenue streams. Following each year’s energy auction, the system planner is responsible for drafting a plan to connect all auction winners to the grid, co-optimizing investment at both the connection and system reinforcement level, with the help of an advanced computational model.

As can be seen in Figure 7, in the energy auction held in 2009, only a fraction of prospective projects secured energy contracts. This shows the effectiveness of energy auctions as a filtering step for differentiating between viable and less efficient projects. This described ‘cooperative planning’ approach serves to reduce uncertainty and enables the planning of an integrated network at minimum cost, while making full use of any scale economies. Enabling facilities investment cost is fully borne by each respective developer, while shared facilities cost is allocated to each plant on a usage basis according to a MW-km methodology. This ‘beneficiary pays’ approach incentivizes developers to coordinate with respect to the location and timing of new connections. In addition, the risk of plant construction delays is shouldered entirely by the generation developers, pushing investors to follow the original commissioning plans. Similar to conventional transmission projects, asset delivery is procured through an auction administered by the regulator to ensure a competitive provision of services.

Delivery

The government has placed several prerequisites on companies that intend to participate in a transmission delivery auction [29], in order to avoid market power abuse or ensure that at least part of the revenue is captured by domestic Brazilian companies:

- Private and state-owned companies, either on a stand-alone basis or as part of a consortium, must open Special Purpose Companies (SPEs) in order to participate in the auctions.
- To avoid market power abuse, holders of distribution concessions cannot participate in transmission auctions.
- In the case of multi-firm bid alliances, consortium leadership must be assigned to a Brazilian company.

Candidates compete for a 30-year concession to own the asset and receive an RPI-indexed annual revenue stream (RAP)[17]. The auction may involve a single stand-alone transmission project or can be divided in lots, where each auction deals with a divisible element of a larger project (e.g. substations and cabling). Furthermore, the Transmission Service Provision Contract (CPST) defines target availability levels. If the target is not met, the concessionaire is subject to fines, similar to an availability incentive. Overall, transmission owners are remunerated independently of the actual use of the facilities. The Invitation to Tender specifies a target delivery date and fines are imposed in case of delays. Once construction is completed, the Transmission Owner is responsible for operation and maintenance of the transmission line.

The configuration of the transmission line auctions is a hybrid between two models - a sealed first-price auction followed by an English auction. Both auctions are administered by the regulator, ANEEL. In the first stage, each competitor makes a sealed bid for an Allowed Annual Income (RAP) for a concession period of 30 years. Following the envelope opening, if there are no closely-competing bids, the lowest-bidding competitor is directly declared as the winner. If there is at least one bid close enough to the winning bid (defined as within 5% of the lowest bid), there is a second stage in which the few remaining competitors dispute in an open-outcry descending-price auction, where the lowest bid of the first stage has been set as the reserve price. Similar hybrid auction configurations have been implemented in the past in 3G spectrum auctions in GB and Brazil [30]. According to Klemperer [31], the advantage of an Anglo-Dutch auction is that in the first stage there is no possibility of predatory or entry-deterring behaviour, thus encouraging participation. This is particularly important when a single bidder (e.g. incumbent TO) is perceived to be dominant or able to retaliate.

It is important to note that the winning bidder is responsible for obtaining the right of way and acquiring the relevant environmental licenses. In some cases, this has been proved increasingly difficult, leading to considerable delays. Overall, it is acknowledged that long environmental licensing processes are responsible for slowing down the expansion of Brazil's transmission network.

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[17] *Note that the payment profile is front-loaded to facilitate faster recovery of investment. After the first 15 years, only 50% of the RAP is paid out.*

Most interestingly, for some projects (especially connections for remote large hydro) there is a provision that the final design is not pre-defined but actually is to emerge from the auction. For example, in the auction for linking the Madeira River complex to Sao Paulo (2,500km distance; project initially valued from US$2.9bn to US$4bn), the planner examined a total of 16 options, including several full HVDC, AC and hybrid solutions [32]. Although the socioeconomic studies concluded that a 600kV HVDC was the best solution, ANEEL brought forward two options for competitive bidding:

- All-DC option: Two ±600 kV, 3150 MW transmission bipoles plus two 400 MW back to back converters
- Hybrid AC+DC option: One ±600 kV, 3150 MW transmission bipole plus two 500 kV AC lines

The DC alternative was the auction winner in November 2008, coming 7.5% below the established ceiling. In order to further improve competition in delivery, ANEEL had split the two technology options in different lots. For example, the DC build option was split in 7 different lots, holding separate tenders for each DC line, converter, associated grid reinforcement etc. The process resulted in different owners for each lot and different kit manufacturers. Even though the process was deemed highly successful, the overall integration of the different lots has been characterized by some technical integration challenges. To address such issues, the auction winner has the freedom to revisit the initially proposed design, provided that asset performance will remain the same or ameliorate with respect to the specifications of the winning bid.

Finally, Brazil has introduced re-financing provisions as a gain sharing mechanism. Concessions from auctions held between 1999 and 2006 are not subject to any ex-post regulatory review. However, the concessions from auctions held between 2006 and onwards are subject to a tariff review process (revenue-cap model) that takes place every five years. This review aims to take advantage of potential changes in the cost of debt and any reductions in operation costs as technology advances (e.g. reduction of maintenance costs due to new techniques).

Assessment

Between 1999 and 2008, 87 transmission concessions were auctioned, receiving a total of 399 bids by a total of 112 companies and consortiums. The high number of bidders, heterogeneity of participants (by private companies, public-private partnerships and by state-owned companies) and large representation of foreign companies (e.g. in the period 2006-2008, 57% participation foreign origin) indicate limited transactions costs and low barriers to entry [33].

On average, the value of submitted bids has been considerably lower than the pre-set opening price (in the order of 20-40%). For example, some auctions in 2011 had a difference between winning bid and ceiling as high as 58%. This shows that ANEEL's opening bids estimates are rather conservative and the auction process serves as a useful means of discovering equipment costs, especially if ANEEL's equipment costing are updated periodically to better reflect the underlying reality. This discount amount has been found to be largely influenced by the scope for synergy with other adjacent projects in the region due to scale economies with respect to operation and maintenance [34]. Prospective bidders able to coordinate across a portfolio of projects can provide the most competitive bids. This is even more evident for remote large transmission facilities. In a country as land-diverse and large as Brazil, establishing the needed supply chain (e.g. road network for construction material transportation) can be the most significant cost driver; establishing a remote hub coordinating across a number of projects can lead to important scale economies and material savings.

Overall, evidence shows that the number of bidders is positively correlated to the average difference between bids and ceiling price, illustrating that competition can apply downward pressure to delivery. As a consequence of increasing competition, the RAP per km has followed a steady downward trend over time.

However, auction rounds held in 2012 have seen a limited amount of bidders interest. Many of the winning bids have failed to offer discounts relative to the ceiling price and one project has repeatedly failed to attract enough interest. In addition, there are reports of increasing consolidation, with state-owned companies winning most auctions. This has been attributed to the nature of offered projects, which are subject to increased uncertainty due to environmental issues. It has been argued that when facing such political uncertainty, incumbents and state-backed players have a competitive advantage due to the government's potential ability to support such ventures via other means (e.g. government-driven resolution of public opposition).

C.4. CHILE

Overview

Chile is a fast-developing country with energy consumption growing about 5% per year over the last decade. Chile has been a pioneer in electricity deregulation since the unbundling between generation, transmission and distribution services that took place in 1982. Despite the novel cost allocation methods implemented, no formal transmission expansion process was put in place during the 1990s. Transmission expansion remained a market-led exercise where new investments were primarily driven by generators. Reinforcements were decided through two-party negotiations and no optimality checks for the global system took place. Expansions were possible only when large users were willing to enter in a bilateral contract where they paid the full cost, while the 'trunk' upgrade was shared with free-riders [35]. Contrary to most regulated regimes, system owners were not mandated to provide connection services for end consumers. As a result, consumers' reliability and load-serving needs were overlooked and development of shared interconnecting corridors remained weak. Major framework changes were implemented in 2004, when a centralized process was introduced to manage network transmission planning and meet the country's fast-growing demand and need for renewables integration[18][36].

Planning

Under the new planning regulation, transmission is seen as an open access passive market facilitator and a planning process involving all stakeholders is followed. The National Energy Commission (CNE) produces an indicative generation expansion plan for the next 10 years. This study utilizes a reference investment cost database as well as fuel cost and demand growth projections prepared by the ISO (CDEC). Transmission reinforcements are considered and uncertain hydrological conditions are captured through 50 scenarios. The generators that would be profitable over that horizon, defined as plants having IRR equal to an estimated WACC, are assumed to go ahead. This generation expansion scenario is updated every 6 months, to reflect the changing view of the regulator with respect to load growth, fuel costs etc.

In terms of transmission, the new regulatory framework separated the system in three segments:

- **Trunk** incorporates the asset base over 220kV, mostly on the main North-South corridor for serving total system demand.

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[18] *Support to non-conventional renewable sources of generation is offered through a renewables portfolio quota scheme; set at 5% for the period 2011-2014 and subject to a yearly increase until reaching 10% in 2024.*

- **Subtransmission** assets enable access to consumers. Subtransmission assets of capacity below 2MW are not regulated.
- **Additional Transmission** assets enable the connection of power plants to the main system.

For the Trunk and Subtransmission assets, the generation scenario constitutes the main input for CNE to produce a network expansion plan (known as the Trunk System Study) for the next 15 years. A new Trunk System Study is drafted by CNE every four years according to the latest generation scenario. The actual planning task is usually outsourced to an external consultant who runs a cost minimization optimization against the given scenario using a security-constrained economic dispatch methodology. Expansion costs of candidate lines are determined from a reference O&M database. It is also important to note that any stakeholder can propose a transmission project to be included as a candidate in the analysis. The preliminary plan is submitted to a public hearing where all stakeholders (regulator, generators, TOs, distribution companies, large consumers and representatives of small consumer groups) can participate and review the proposed investment schedule. Participants that disagree with the proposal must raise their case with a special tribunal called Experts Panel. Once disputes are resolved and all agents agree, the 4-year plan is submitted for the final approval of the CDEC Board, which consists of 10 stakeholder representatives [37]. The final output is a 4-year referential plan which is revised annually by CDEC to assess its applicability to the unfolding system reality. Every year, the final plan to be implemented for that year is subjected to a stakeholder consultation to determine whether the realized load, generation and costing scenarios are still valid and justify the investment. Stakeholders can again challenge the plan and raise their concerns to the Experts Panel. The above process applies to all main system reinforcements. Enabling facilities required for specific generation projects (referred to as Additional Transmission assets in Chile) are fully financed and constructed by the project developer and usually operated by the ISO (CDEC).

Since 2004, two trunk planning rounds have taken place. Initially, pure deterministic planning was employed; the optimal solution was drawn for a single scenario deemed as the best future forecast according to the regulator. In addition, no uncertainties in equipment costs and load growth were considered. Since the second Trunk system Study carried out in 2010, the regulator considers multiple scenarios and a Min Max regret criterion to manage uncertainty. However, it is important to note that this robustness criterion is applied ex-post to scenario-specific optimum solutions rather than used as the optimization's decision criterion across multiple scenarios [38]. In 2010, three future generation and two load growth scenarios were included in the analysis. Despite the consideration of diverse scenarios, critics argue that transmission expansion remains short-sighted, preventing the increase of competition in an already heavily concentrated market (three companies control 80% of installed generation capacity). Myopic additions do not allow new entrants to take advantage of economies of scale and participate in the market with manageable connection tariffs. Extending the current framework to enable anticipatory investment is seen as an efficient way for removing these barriers and proactively increasing the capacity of the country's main longitudinal corridors to allow faster integration of small plants and renewable [39].

Delivery

The new planning framework also introduced competition in transmission delivery. Naturally, the transmission expansion plan to be implemented involves upgrades of existing system assets and new projects. Upgrades to the existing system are assigned to the facility owner given that the .

New projects are subject to a competitive auction process managed by the ISO (CDEC). In order to participate in such an auction, new TOs must first incorporate into a Transmission Company separated from any generation and distribution functions. Participants bid for an A-B project for a particular capacity, a particular technology and number of towers (as described in the call to tender), but they have to decide on the routing, get right-of-way consent and undertake the required environmental impact studies. As a result, the key design criteria considered by competitors are: line route length optimization, reduction of environmental impact and settlements with affected land-owners.

For each new project a closed envelope auction is held, where each participant bids for an RPI-indexed fixed annual revenue to cover asset construction, operation and maintenance. The project is awarded to the company that offers the minimum AVI (annual revenue to cover investment) and COMA (annual revenue to cover operation and maintenance) for a period of 20 years. Note that AVI+COMA is the sole revenue stream; no congestion revenues are assigned to winners and their remuneration is independent of the line's utilisation. As in Brazil, the auctions are opened with maximum bid (effectively acting as reserve prices) set by the regulator according to reference equipment costs consistent with the estimates used in the planning cost-benefit analysis. Furthermore, the ISO is responsible for co-ordinating system operation and maintenance across the multiple TOs. The auction winner starts receiving remuneration when the facility starts operation. Penalties are imposed for delivery delays with respect to the expected date as defined in the tender call. Finally, the TO is liable for penalties due to service disruptions or deviations from the country's operational security standards.

Assessment

The Chilean transmission asset base has experienced significant growth in the last decade; from \$929m to \$2,789m.There have been two auction processes so far. The first trunk expansion decree was enacted in 2007 and 23 upgrade projects were auctioned off. The second auction round held was deemed very successful in procuring assets and services with a total value of about \$900m. As can be seen in Figure 8, the majority of concessions involved construction of new assets.

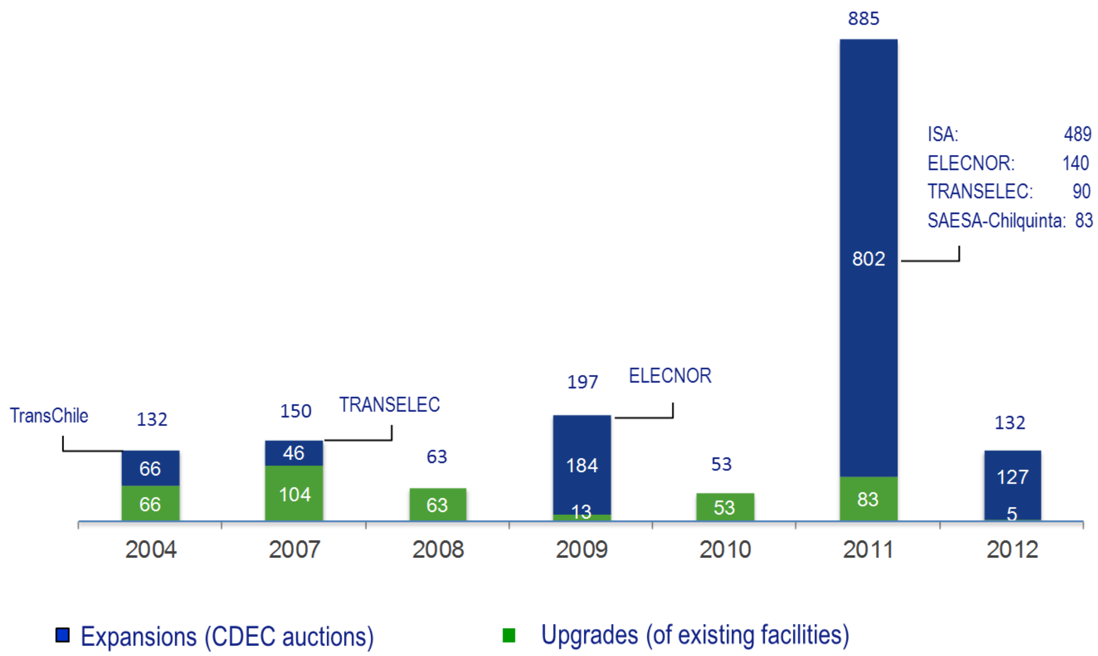


Figure 8: Annual transmission auctions for 2004, 2007-2012. All numbers in million USD [7]

Details of the largest projects and the corresponding bid interest in the 2011 auction are presented in the table below. A number of transmission developers have successfully participated in these two auctions, with the incumbent Transelec only winning a fraction of the auctioned projects. In 2011, auction winners included international firms from Colombia, Spain, Israel and Brazil entering the Chilean market for the first time. This shows that there are limited barriers to newcomers and Chile has been successful in reaping competition benefits at the international level, making use of worldwide technical and managerial expertise.

Table 14: SIC 2011 auction details

Project Name	*Reference Project Value (M USD)*	*Length (km)*	*COMA (%)*	*Bidders*
Second Substation Lo Aguirre	69.02	-	1.44	5
Charrua – Ancoa	140.40	196.55	1.44	3
Pan de Azucar – Polpaico 2x500kV	280.00	401.80	1.50	5
Maintencillo – Pan de Azucar 2x500kV	130.11	209.20	1.58	5
Cardones – Maintencillo 2x500kV	79.32	132.40	1.44	5
Cardon – Diego Almagro 2x220kV (1C)	37.00	152.00	2.07	5
Ciruelos – Pichiropulli 2x220kV (1C)	45.49	83.00	2.07	2
CER 100/-60 MVaR S/E Cardones	20.70	-	2.07	3

An important observation consistent with what has been observed in the Brazil auctions is that the winning (minimum bids) have consistently been significantly lower than the maximum acceptable bid as indicated in the figure below. This further reinforces the notion that delivery auction are a useful tool for equipment cost discovery and that competition in delivery can lead to direct savings.

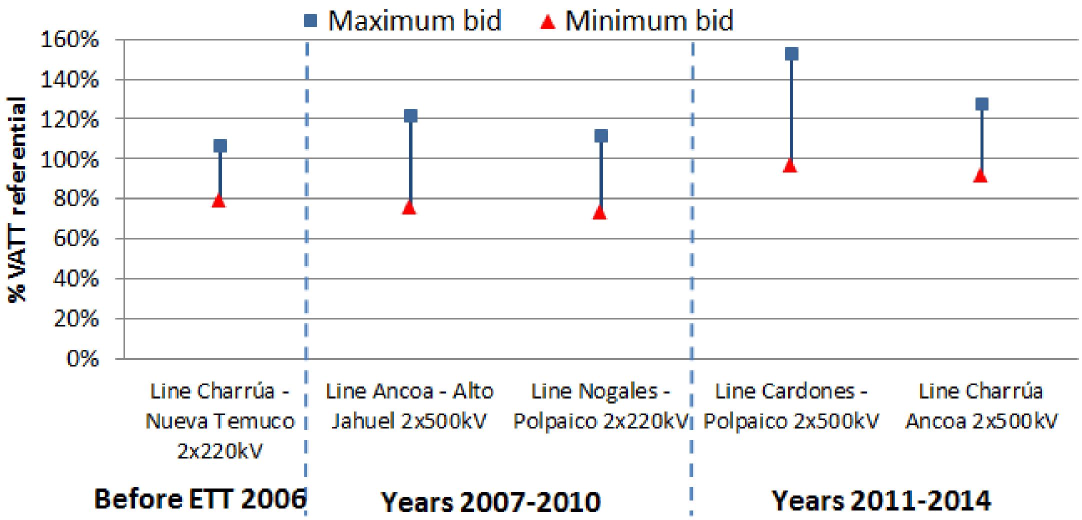


Figure 9: Transmission Delivery Auction Bid WACC in Chile [40]

However, the experience so far has shown that project delivery times have consistently been longer than the design specification. This has been mainly attributed to the rights of ways and consenting process, with new entrants underestimating the time and effort needed to secure the first project stages. In view of this, the incumbent TO (Transelec) has claimed that auction winners suffer from winner’s curse, especially given the high penalties associated with project delivery delays.

Table 15: Indicative and Actual Project Construction Duration [7]

Project Name	*Length (km)*	*Transmission Owner*	*Project Duration Decree (months)*	*Actual Duration (months)*
Charrúa-Cautín 220 kV	200	Transchile	37	56
El Rodeo-Chena 220 kV	20	Transelec	31	49
Nogales-Polpaico 220 kV	90	Transelec	24	42
Ancoa-Alto Jahuel 500 kV	260	Elecnor	39	51

It is worth noting that in the most recent auction round the incumbent TO decided to not bid for any projects, deeming that the required delivery dates were very difficult to meet. As in most competitive schemes, winner's curse can be a real risk that can compromise the overall electricity expansion plan. There have been some isolated incidents worldwide where auction winners simply abandoned the development project, preferring to incur capital losses than continue investing in a problematic venture running severely over budget. For this reason it is important that relevant 'last resorts' measures are in place to deal with a potential failure to deliver.

C.5. ERCOT

Overview

The Texas area is effectively isolated from the rest of the US, with only two interconnectors to other systems. As a result, ERCOT can be seen as an 'electrical island' with some limited connection facilities to the eastern/western US and Mexico. Naturally, the Federal Energy Regulatory Commission (FERC) has no jurisdiction over the Texas electricity sector; regulation is exercised by the Public Utility Commission of Texas. However, ERCOT is a constituent council of the North American Reliability Council and as such follows the same reliability codes as most other US states.

The ERCOT electricity system covers 85% of Texas load and serves a growing population of 23 million consumers. It consists of over 40 thousand circuit miles of high-voltage transmission and over 550 generating units to cover a peak demand of 68GW. The ERCOT market size has been estimated at around $34 million, with over 1,100 entities actively buying, selling and transporting wholesale electricity [41]. ERCOT is a nodal market, where generators are paid their Locational Marginal Prices and load entities pay averaged load-zone prices. There is a total of 4 load zones in Texas. Load growth and the push for renewables has resulted in a very active electricity sector, with 8GW generation currently being built and over 40GW of new generation requests under review, of which 20GW are new wind farms. To meet these expansions, 6,900 circuit miles of transmission are currently under development totalling $8.9 billion.

Planning

ERCOT, formed in 1970, is the not-for-profit ISO for the Texas area and has been overseeing the region-wide planning since 2001. Initially this task was limited to getting the incumbent TOs to coordinate their investment plans through joint power flow studies. Since 2003, the transmission planning process was formalized in what is called the Regional Planning Framework. Under this scheme, all candidate transmission projects are classified into one of four tiers, depending on each project's cost and impact on reliability. The classification process is outlined in Figure 10. Note that 'neutral projects' that have only localized impacts and are directly associated to generation connections do not undergo a formal review. A Certificate of Convenience and Necessity[19] (CNN) essentially guarantees to the developer that all costs associated with building and maintaining a transmission project will fully pass through to consumers through tariffs. The CCN requirement primarily relates to projects involving a new right of way. CCN are contested cases that focus on the transmission line route issue. PUCT may approve the CCN application by selecting one of the proposed routes, approve it in part or deny the application. It is only after a CCN has been granted that the Transmission Service Provider may proceed to acquire the right-of-way and begin construction.

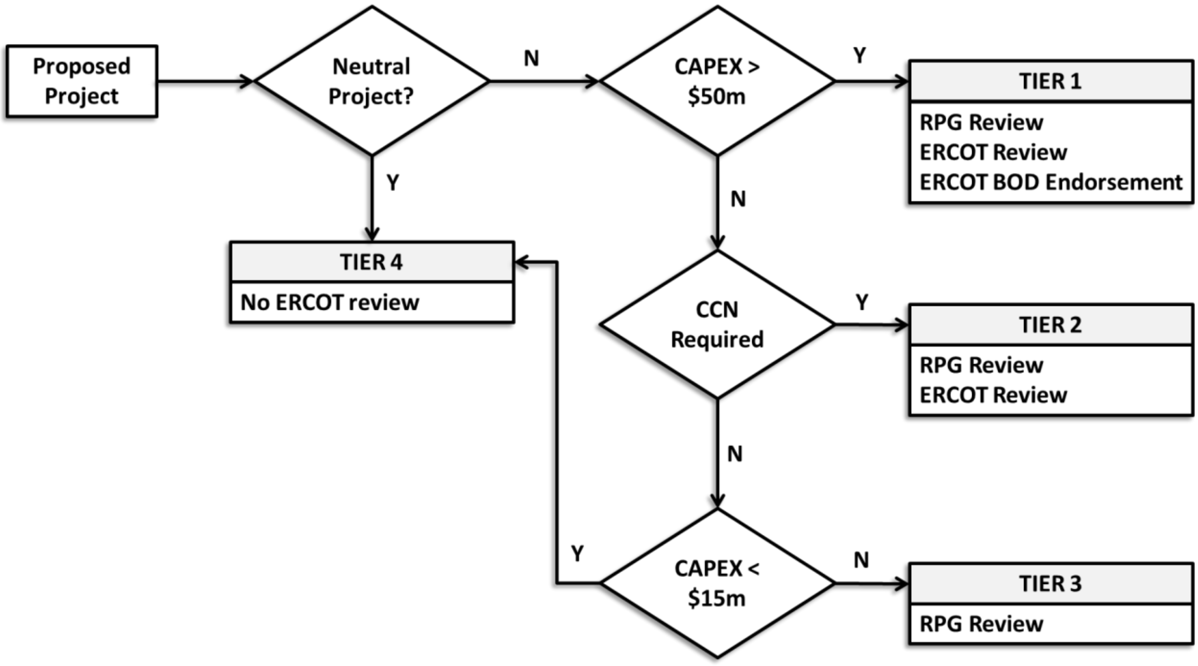


Figure 10: Project classification flowchart in ERCOT [42].

The final decision on Tier 1-3 projects is given by the Regional Planning Review Group (RPG). More specifically, RPG is led by ERCOT staff and membership is open to all market participants, transmission and distribution service providers, PUCT staff and other stakeholders [43]. The RPG holds monthly meetings where the primary role is to provide input into transmission planning studies and review proposed transmission projects.

This Regional Planning Framework covers all four Tiers and consists of four discrete planning processes described below.

1. Coordinated five-year plan

The Five-Year Transmission Plan (FYTP) is jointly developed annually by ERCOT, RPG and TSPs. The primary goal is to identify projects necessary so that the Texas electricity system abides to the standards set by the North American Electric Reliability Corporation[20] (NERC). In addition to security-driven developments, the aim is to also identify economics-driven investment that will

[19] As defined in Utilities Code, Public Utility Regulatory Act, Electric Utilities, Chapter 37: Certificates of Convenience and necessity.

[20] NERC is a non-profit non-government organisation that promotes and oversees reliability and adequacy of electricity transmission services in the interconnected system of US, Canada and part of Mexico. NERC develops operation security standards, adjudicates compliance and can levy monetary penalties in cases of standards' violation.

enable congestion reduction and better utilization of existing generation resources. The plans included in the FYTP are not to go ahead until they have been endorsed by ERCOT's Board of Directors. Effectiveness of each candidate project is evaluated through simulations across a wide range of system operating conditions. In order to determine the most favourable between competing candidates, other benefits such as operational flexibility and compatibility with future plans are taken into account.

2. Long-term system assessment

This is an analysis focusing on the long-term system needs, looking at strategic options available. The Long-Term System Assessment (LTSA) is performed by ERCOT and the RPG on a biennial basis and reviewed annually. LTSA uses scenario analysis to assess transmission planning needs over the next 20 years. Given this horizon, the role of LTSA is to evaluate different scenario projections and identify upgrades that are robust across a wide range of possible futures. This way it is possible to incorporate future considerations and provides a useful long-term vision to near-term decisions with an ultimate goal of ensuring long-term value for money.

3. Individual project reviews

Any market participant can propose a new project. Such projects are included in the five-year plan and their need case is reviewed at the appropriate time.

4. Transmission Owner plans

These are plans drafter by each incumbent TO . They usually involves smaller projects (CAPEX < \$15m) and are exempt from the formal ERCOT approval process.

From the above it follows that there are two main need avenues for identifying project needs: common consultation between ERCOT and RPG and stakeholders directly proposing new developments.

Delivery

Texas is divided in a number of areas, with each area being serviced by an incumbent TO (captive consumers). The respective incumbent TO is responsible for delivering all transmission projects in his area and carries out all line engineering and routing studies. In the case of cross-zonal projects we have what is called 'rule-based assignment, where the exact ownership and construction details are worked out according to a set of rules (depending on who owns the endpoints etc.). The ultimate go-ahead to acquire the right –of-way and begin line construction is given by PUCT. This is to ensure that the routing option being proposed is acceptable. Incumbent TOs receive a regulated return on investment through tariffs paid by load and plants, while their revenue is decoupled from the eventual asset utilization.

C.6. ERCOT CREZ

Overview

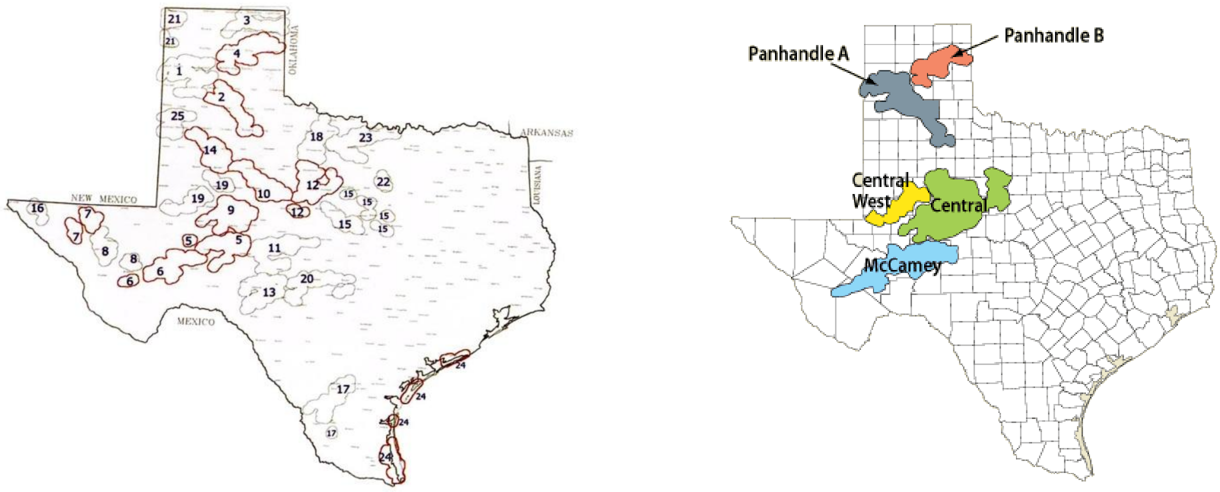
In the above sections we explained how 'conventional' transmission planning and delivery takes place in ERCOT. In this section we present the CREZ (Competitive Renewable Energy Zone) process; an 'ad-hoc' transmission planning and delivery regime instituted in ERCOT to facilitate connection of large-scale renewables.

In the last decade, the introduction of the Renewable Portfolio Standard (10,000 MW of renewable energy by 2025 [44]) coupled with related tax incentives and the state's vast wind resources has led to an increased investment in wind farms. Prior to the CREZ process, ERCOT began curtailing MCCamey wind farms due to transport constraints, with this problem affecting other plant owners in the following years. Due to Texas open access transmission policy, as of June 2003, wind farm owners are reimbursed for the energy and renewable quota price in such curtailment events [45]. To accommodate further investment and tackle the investment-generation conundrum (also referred to as the 'chicken and egg' problem [46]) , Texas has adopted proactive transmission planning as part of its long-term strategy. As of late 2012, the CREZ process has resulted in over 2,000 miles of transmission lines being built for the accommodation of over 11GW of wind power.

Planning

The first step of the CREZ process was to identify the locations with the best-quality wind resource. More specifically, ERCOT commissioned a state-wide wind study [47] to identify suitable sites satisfying the CREZ requirements (high wind factor, environmental suitability etc.). 25 CREZs were initially identified and ordered according from best to worst according to the recorded and projected wind speeds. ERCOT proceeded to analyse different transmission alternatives [48] of connecting the identified wind-endowed areas. Before its official release, the wind study report was subject to a consultation process where stakeholders had the opportunity, and indeed in some cases did request, the recalculation of the quoted wind capacity factors. From the 25 initial zones, 9 were later eliminated due to limited developer interest while another 8 demonstrated a lower than required level of financial commitment. The remaining 8 zones were deemed to be suitable for wind development and were granted CREZ status. In October 2008, PUCT issued a final order [49] designating the five CREZs, shown in Figure 11(b). The commission's decision was based a variety of factors such as:

- Level of financial commitment
- Wind quality as indicated by the state-wide wind study
- Presence of non-renewable plants in the area for the provision of ancillary services
- Environmental considerations
- Economic efficiency



(a) **(b)**

Figure 11:
(a) Potential wind resource map. Zones are numbered in order of capacity factors, with zone 1 being the most wind-rich area.
(b) The five CREZs eventually chosen by PUCT.
[50]

Following this designation, four scenarios were brought forward, each one specifying a target new wind capacity for 2020 and the corresponding sharing between the five areas. As can be seen in Table 16, scenarios ranged from 12 GW up to 24 GW of wind capacity.

Wind Zone	*Scenario 1*	*Scenario 2*	*Scenario 3*	*Scenario 4*
Panhandle A	1,422	3,191	4,960	6,660
Panhandle B	1,067	2,393	3,720	0
McCamey	829	1,859	2,890	3,190
Central	1,358	3,047	4,735	5,615
Central West	474	1,063	1,651	2,051
Total	12,053	18,456	24,859	24,419

Table 16: Capacity of new CREZ wind by scenario [MW] [50]

While wind factor is a significant driver, a very important factor to wind farm siting is also the availability of transmission facilities to export to the main load centres. For this reason the next step of the CREZ process was to determine the optimal connection plan for scenario 2. An extended transmission optimization study for each scenario was carried out by ERCOT based on a large-scale cost-benefit analysis. This was coupled by an Ancillary Services study [51] to ensure adequate levels of reliability could be maintained under all scenarios.

As a form of user commitment, each wind farm developer had to post as collateral 10% of developer's pro rate share of estimated capital cost of transmission investment. About $500m collateral was posted to support the Scenario 2 build-out. Developers were asked to file testimony and demonstrate their financial commitment in the form of pending or signed interconnection agreements, interconnection studies, project financing and leases [52].In addition, signed-up developers have to come online within one year of the transmission infrastructure being built or face penalties.

Scenario 2 was voted in to be implemented at a projected interconnection cost of $4.93bn (plus $580-820 million in collection system costs) and involving the commissioning of 11.5 GW of new wind power additions (to the existing 6.9GW) by end of 2013. The proposed design is projected to provide 65TWh of annual energy at an average cost of 0.42m$/MW [53]. Although the scenario choice was left exclusively to PUCT, the Texas Industrial Energy Consumers (TIEC) consortium has since challenged the efficiency of this decision in court, arguing for the lowest build-out scenario.

Delivery

Following the PUCT scenario decision and ERCOT transmission planning study, CREZ construction began in late 2010 with an aim of completing all anticipatory transmission works by start of 2014; a period of 3 years. The actual asset delivery was determined through a competitive tendering process. Interested TNSP (Transmission Network Service Providers) were asked to bid for the building and operation of CREZ transmission projects. New entrants along with incumbents were considered as potential TOs.

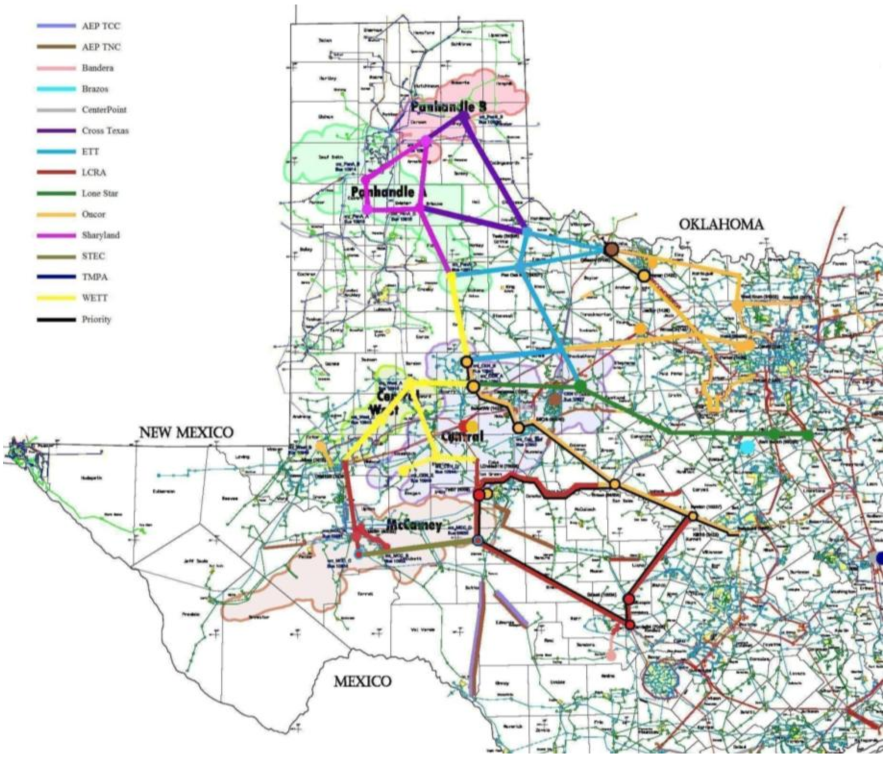


Figure 12: The CREZ transmission projects assigned to the 15 TNSPs [50]

In terms of selection criteria, the overall framework outlined by the Public Utility Commission of Texas required for each prospective TNSP to demonstrate ability to construct, operate and maintain the facilities. For this reason, a multi-criteria process was established, where TNSPs were asked to provide evidence of current and expected capabilities to finance, license, construct, operate and maintain the Transmission Facilities in the most beneficial and cost effective manner and the expertise of TNSP staff. More specifically, some of the criteria were:

- Proposed project capital, operating and maintenance costs.
- Current and projected financial resources.
- Proposed schedule for development and completion

- Demonstration that the prospective TNSP understands all obligations and contract requirements
- Previous transmission experience and performance track record for (if any) existing transmission projects (e.g. average direct operating and maintenance costs-per-mile of same-voltage transmission lines over the last five years).
- Indicate their current credit rating and the cost of financing $100m (utility incumbents) and $500m (privately held TNSPs) of debt for 1,3,5,10 and 30 year terms.
- Proposed return on equity if they were selected.
- Any history of mergers, bankruptcy, dissolution etc.
- Expected use of historically underutilized businesses (HUBs are businesses that employ a large number of historically disadvantaged populations e.g. Native Americans). This is to ensure that funds are channelled to the wider Texas community.

The exact weighting of each criterion on the eventual selection decision was not made public. The selection process took about 12 months and eventually all the initial applicants were granted concessions with the exception of a firm that went bankrupt in the negotiation process. In summary CREZ projects were assigned to a total of 15 different TNSPs, 7 of them being incumbents and 8 being new entrants. A more detailed account of the chosen TNSPs is shown in Figure 12.

Assessment

Overall the CREZ process was characterized by high complexity which was exacerbated by the tight timescales of the project; the first phase (wind and transmission study, user commitment) lasted only about three years. More precisely, the legal proceedings involved interventions from over 65 parties and the filing of over 1,400 documents related to the financial commitment testimonies of prospective wind projects totalling more than 18GW [54].

It is important to note that whereas the CREZ planning process has been 'branded' as one the first anticipatory approaches to transmission investment, potential 'first-arrival' developers were asked to provide some financial guarantee. However, it is important to note that firmness of transmission access is an indispensable characteristic of ERCOT. Guarantee of access priority was regarded as the only incentive for prospective wind developers to participate in the CREZ process and post the required collateral. However, implementation of priority dispatch would directly contradict the open access policy adopted by ERCOT and interfere with the LMP market functions. Naturally, a large debate is currently taking place to determine whether the developers taking part in the process should be granted dispatch priority over subsequent entrants, securing them from future free-riders in the case of over-subscription. This discussion concerning priority access is still on-going [55] with several physical and financial approaches being proposed by the relevant ERCOT taskforce [56]. The most discussed mechanisms are the allocation of Congestion Revenue Rights to CREZ developers and the use of an Automated Offer Curve that ensures CREZ projects are prioritized in the market clearing process.

Overall CREZ will result in the construction of 2,700 circuit miles to enable the wind energy transportation to the main load centres of Houston and Dallas. Out of the projected 18GW of new wind to be developed by 2020, the current build-out stands at about 6GW.

C.7. NYISO

Overview

NYISO is an independent non-profit corporation established to ensure the reliable operation of the state's transmission facilities. NYISO administers the electricity market and the transmission charging process. It is also responsible for planning the New York State electricity system and evaluating the impact of new generation and load to the system. NYISO operates a network of 10,892 miles of HV lines, total generation capacity of 38GW and peak load of 34GW (as of 2010). In 2009, the NYISO electricity market had an annual transaction volume of $75 billion [57] and over 400 participants.

NYISO has a shared governance structure. It is governed by an independent 10-member Board of Directors, none of who are affiliated with market participants, and three formal committees comprised of a wide array of stakeholder representatives. The Board is responsible for NYISO's operations management and financial affairs. In addition there are three formal committees:

1. Management Committee (MC) is the main instrument for stakeholders to communicate their position to the Board. MC supervises all other committees and develops recommendations to the Board. All parties to the NYISO Agreement[21] have voting representation and a 58% vote majority is needed to pass a measure.
2. Operating Committee: oversees the procedures for coordinating the power systems operation.
3. Business Issues Committee: oversees and establishes procedures to ensure the non-discriminatory operation of NYISO electricity markets.

NYISO is part of the Eastern Interconnection, a member of the Northeast Power Coordinating Council (NPCC)[22] and is regulated by the Federal Energy Regulatory Commission (FERC).

Planning

In NYISO's jurisdiction there exist six investor-owned utilities (TOs) and two transmission authorities. It is important to underline that NYISO's role in transmission planning is quite different to the ISOs in other jurisdictions, by adopting a market-based approach. NYISO does not directly "mandate" facilities to be constructed for reliability purposes according to a periodic plan. Rather, it assesses system-wide reliability needs and solicits solutions from the market (merchant investment) and regional TOs. NYISO is responsible for co-ordinating system-wide planning across these entities. The philosophy is that by soliciting solutions from merchant bodies, the end consumers are partly relieved from the financial risk of new projects.

More specifically, the Comprehensive System Planning Process (CSPP) is NYISO's market-based planning framework. It evaluates resource adequacy and transmission system security for the next 10 years and evaluates solutions to meet the reliability standards. It takes place every two years and is comprised of three major components carried out sequentially:

i. Local Transmission Planning
ii. Comprehensive Reliability Planning
iii. Economic Planning

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[21] *In the NYISO Agreement, five Sector Groups are recognized: Generation Owners, Other Suppliers, Transmission Owners, End User Consumers and Public Power/Environmental Parties.*

[22] *NPCC Eastern Interconnection It is also tied to the Quebec Interconnection through four HVDC ties.*

In general, reliability-driven investment refers to investment undertaken to alleviate violations in the security standards. On the other hand, economic-driven investment refers to reinforcements that have positive net economic benefit when comparing the alleviated congestion savings minus the cost of expanding the infrastructure.

Local Transmission Planning

The planning cycle begins with a review of the LTPs submitted by the six incumbent New York TOs. Stakeholders can review the planning criteria and assumptions posted by each Transmission Owner as well as examine each TO's planning model which is publicly available. Each TO proceeds to plan against the accepted assumptions and the reliability criteria set out by NERC (North American Electric Reliability Corporation), NPCC (Northeast Power Coordinating Council) and the NYSRC (New York State Reliability Council). Each LPT describes the reliability needs being addressed as well as the various assumptions and methodologies used. Upon successful review through the stakeholder consultation process, the six LTPs are included in the base-case of the Reliability Needs Assessment (RNA). NYISO, in conjunction with other market participants, evaluates the system-wide Loss of Load Expectation (LOLE) and security against the NERC, NPCC and NYSRC reliability standards under the different assumptions/scenarios. The RNA report, outlining all problematic cases not covered by the local plans is filed for approval to the NYISO Board of Directors.

Comprehensive Reliability Planning

Local planning is followed by the Comprehensive Reliability Planning (CRP) process [59]. The purpose of this step is to propose solutions for addressing the system needs identified in the RNA report. A request for market-based solutions is issued, in search for alternative approaches to meet those needs. Note that generation, transmission and demand-side solutions are considered as suitable candidates and evaluated on the same basis; service type is not pre-specified. In the cases that market interest is not sufficient and no suitable proposition is brought forward, the CRP process provides for the identification of:

- Regulated Backstop Solutions proposed by a designated TO
- Alternative Regulated Solutions proposed by any market participant

Subsequently the NYISO reviews and evaluates the fitness of all proposed solutions and produces the Comprehensive Reliability Plan with detailed schedules of the works to be carried out.

Economic Planning

The third and final step of the CSPP, which was first instituted in 2009, is Economic Planning, pursuant to FERC Order 890 [60]. It consists of two phases; the study phase and the project phase. The first phase involves NYISO carrying out the Congestion and Resource Integration Study [61] (CARIS). The CARIS report presents an assessment of congestion costs projected over a 10-year horizon, where different scenarios are drawn to reflect alternative load growth, fuel price, generation additions and environmental goal forecast paths[23]. The top three 'congestion groupings' are identified and a list of transmission, generation and demand-response projects for relieving the network is presented. In addition, NYISO performs indicative cost benefits analysis for the different candidates without going into technical feasibility issues. The role of this first phase study is to indicate which of the three approaches (generation, transmission or demand-response) is most

[23] *10 and 8 scenarios were used in the 2009 and 2011 CARIS analysis respectively.*

likely to have the highest cost/benefit ratio in relieving each congestion grouping and act as a proxy for gathering transmission developers' interest. The CARIS report must be approved by the NYISO Board.

In the second phase, developers are asked to propose projects for alleviating the three identified congestion groupings. Developers can submit their suggestions and ask NYISO to undertake a more detailed analysis of the proposal's benefits and its allocation. Note that Load Serving Entities (LSEs) are recognized as the only congestion relief beneficiaries. The metric used by NYISO for benefit quantification and allocation is the sum of production cost savings. For an economics-driven project to go ahead and qualify for cost recovery through NYISO's tariffs, it must fulfil the following three criteria in addition to being approved by the NYISO Board:

i. A capital cost of more than $25 million
ii. Benefits outweigh costs over the first 10 years of operation
iii. The approval to proceed with the project is at least 80% of votes vast by beneficiaries on a weighted basis.

Transmission project developed by non-NYTO entities fall under the 'Interconnection process' rather than the 'Transmission Expansion process' and are subject to a different planning and regulatory regime [62]. More precisely, these works involve either enabling works (referred to as attachment facilities) or interconnection with other FERC jurisdictions. NYISO is responsible for all' cross-border' transmission interconnections [63].

<u>Cross-border co-ordinated planning</u>

Of great interest is the way that NYISO coordinates its planning with neighbouring systems. As set out in FERC Order 1000 [64], coordination with other systems is of increasing importance. ISO New England, NYISO and PJM follow a planning protocol to enhance planning coordination and limit any seams issues that may arise between the three jurisdictions. As set out in the 2011 Northeast Coordinated System Plan (NCSP) [65], the key tasks of this coordination procedure are to:

1. Exchange data and planning models among all parties. In addition to the Northeast Interconnection members, data is also provided by the ISOs of neighbouring (and connected through HVDC tie lines) systems; Québec Interconnection, Ontario and New Brunswick.
2. Coordinate interconnection requests likely to have cross-border impacts.
3. Periodically[24] develop and publish the Northeast Coordinated System Plan that integrates:
    a. System expansion plans
    b. Load growth projections
    c. Impending infrastructure commissioning/decommissioning
    d. Information on available distributed resources (e.g. demand-side response programs)
    e. Transmission projects jointly identified as having the potential to resolve seams issues and increase the coordinated system performance.
4. Allocate costs associated with projects that have cross-border impacts according to each party's pricing methodology.

[24] *Although there is no explicit definition as to how often NCSP should be produced, it has been produced annually since its inception.*

To ensure the protocol's implementation, the Joint ISO/RTO Committee (JIPC) and a stakeholder group called the Inter-Area Planning Stakeholder Advisory Committee (IPSAC) have been instituted. IPSAC reviews and provides input on the assumptions and scope of the interregional planning analysis. JIPC is responsible for:

- Performing studies on current and oncoming projects with interregional effects
- Evaluating interconnection needs and opportunities between the three systems
- Interregional market efficiency analysis: Identification of transmission interfaces that may limit economical 'cross-border' transfers and quantify the associated constraint cost volumes.

NPCC's Taskforce for Coordinated Planning (TFCP) reviews resource adequacy and the area's compliance with local security standards.

Delivery

When it comes to projects identified through local planning, there is no competitive delivery of assets in NYISO through auctions. Instead, projects are assigned to the incumbent TO who is rewarded with a regulated return on investment and is incentivised to deliver reliable assets on time with different bonuses/penalties.

As mentioned before, in the case of market-solicited solutions that result through the Comprehensive Reliability Planning and Economic Planning processes, solutions essentially compete in terms of level of service and cost/benefit ratio. This constitutes an effective combination of planning and delivery in a single step, ensuring that the most beneficial approach can indeed be identified and commissioned, while delivery risk lies with the firm proposing the solution.

Assessment

NYISO's latest corporate strategic plan [66] setting out the firm's future direction, highlights the need for more collaboration among neighbouring grid operators for preserving security and optimizing operation through shared use of resources (e.g. sharing of reserves). In addition, the use of smart technologies and increased flow of real-time data will contribute towards this goal. Finally, coordinated planning through the Eastern Interconnection Planning Collaborative (EIPC) is seen as a topic of increasing urgency and importance.

Overall the NYISO planning framework has been designed to address FERC Oder 2000, according to which FERC members are encouraged to 'pursue market-motivated operating and investment actions for preventing and relieving congestion' [67]. The scope of market-solicited solutions is set to expand to include storage solutions, making NYISO the first US grid operator to consider such technologies competing at a market level with generation and transmission services. NYISO has seen increased investment in flywheels over the last 3 years, with studies showing that their frequency regulation performance is better and cheaper than using generators' automatic ramping [68]. Interestingly, NYISO's first 20MW flywheel installation was branded by the White House as one of the '100 recovery act projects that are changing America'[69]. This has spurred FERC to introduce Order 755 [70], which remedies undue discrimination against storage solution in the procurement of frequency regulation. All the above show a clear appetite for introducing advanced operational measures which can displace traditional asset-heavy solutions (e.g. construction of new pumped storage facility for frequency response services). The introduction of flywheel storage technology is a good example of an innovative solution being enabled through a market-lead planning framework.

FERC has commended on NYISO's shared governance structure and the resulting cooperation among stakeholders. The vast majority of revisions to market rules and procedures filed with FERC have been developed through consensus among the NYISO stakeholder committee. This shows how the independent governance structure of an ISO can facilitate the organic evolution of the planning and delivery process to adapt to the system and user needs while making good use of stakeholders' expertise. In addition, NYISO is seen to be a pioneer in operational timescales. It was the first ISO to implement a state-of-the art wind forecast module. It also uses advanced methodologies to establish accurate day-ahead load forecasts based on regression and classification techniques (Artificial Neural Networks).

Finally, NYISO has also received encouraging comments for its role as market operator. According to FERC, NYISO acting as trade counterparty prevented a significant number of potential stakeholders' defaults, shielding market participants against bad debt losses due to the 2008 banking crisis. For example, NYISO avoided a potential loss of $4 million due to Lehman Brothers bankruptcy, due to its proactive decision to not accept unsecured credit privileges.

C.8. PJM

Overview

PJM is an RTO (Regional Transmission Organization) that is authorized by the federal government to manage the reliability and operation of the wholesale electricity market in all or parts of 14 US states[25], servicing over 60 million end consumers. Overall, it is responsible for managing the operation of 6,185 substations and 59,750 miles of transmission lines [71]. PJM received its full RTO status in December 2002 and is subject to FERC regulation. Apart from operation, it is also responsible for administering the wholesale electricity market (day-ahead, real-time and ancillary services markets), running capacity and FTR auctions and planning transmission expansions to maintain system reliability and relieve congestion.

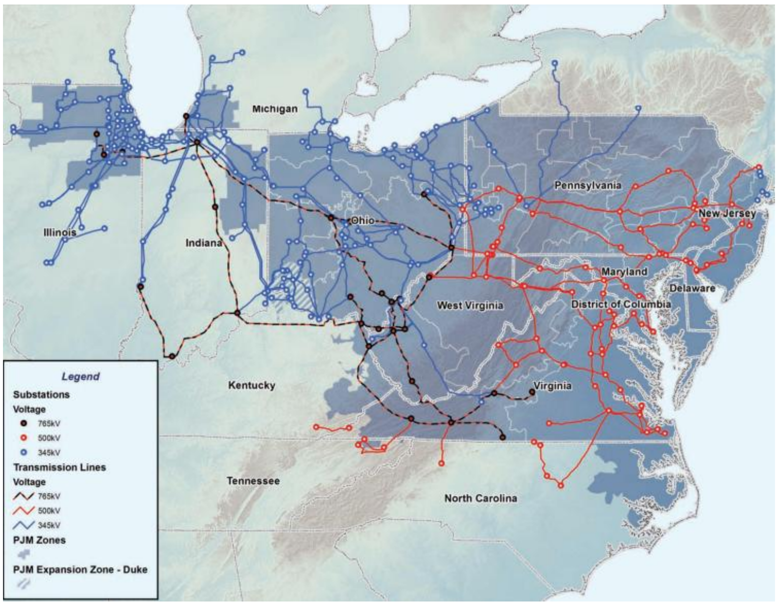

Figure 13: PJM transmission network [72]

[25] *The states are: Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia*

Planning

Transmission Planning is administered through a review process called Regional Transmission Expansion Planning (RTEP) . RTEP's planning horizon is 15 years, looking for violations against the NERC national and PJM regional reliability standards. RTEP is a periodic activity, taking place in 24-month cycles. Overall, the planning process is governed by a specific set of rules and procedures agreed with NERC and set forth in Schedule 6 of the PJM Operating Agreement. It is worth noting that since RTEP's inception in 1997, the process has been updated and enhanced significantly over the years so that a wider range of expansion drivers, such as aging infrastructure, are considered.

According to the RTEP manual [73], the following documents constitute the basis of RTEP :

- A 5-year plan (near-term plan) to address reliability criteria violations. These are revealed through extensive contingency analysis simulations. Conducted annually for the next five years. Can be also triggered from new data, e.g. generator has been dropped from the connection queue (this is referred to as a"retool" study).
- A 15-year plan (long-term plan) is developed to address the construction of new transmission corridors and right-of-way acquisition.

More specifically, the 5-year plan, which includes recommended regional transmission enhancements, including alternatives if applicable, that address the transmission needs for which commitments need to be made in the near term in order to meet scheduled in-service dates. The 5-year plan includes project cost estimates and preliminary construction schedules. In addition, it specifies the level of budget commitments which must be made in order to meet scheduled in-service dates. The commitment may include facility engineering and design, siting and permitting of facilities, or arrangements to construct transmission enhancements or expansions. The 15-year plan identifies new transmission construction and right-of-way acquisition requirements to support load growth. The identification of such needs is done through DCOPF simulations looking for line thermal overloads for years 6-15.

PJM proceeds with developing transmission plans in collaboration with Transmission Expansion Advisory Committee (TEAC). A number of alternative plans are developed by PJM, with TEAC's role being to provide recommendations and advice, with the ability to reject plans that. The PJM Board of Managers reviews and approves system enhancements proposed by PJM. If approved, the project becomes a formal part of RTEP.

The main driver of transmission expansion is the need to meet NERC security standards. There is also scope for economics-driven investment which are projects that can relieve congestion. For an economic-driven project to go ahead, it must have a benefit-cost ratio of at least 1.25. Note that in the benefit quantification, reduction in total production costs is the most important consideration, followed by reduction in load and capacity payments.

Delivery

In PJM the delivery of transmission assets is directly given to the responsible incumbent TO, according to the location of the project, endpoints etc., similar to the 'rule-based' allocation principles of NYISO. There is little scope for competitive procurement of transmission services.

Incumbent TOs (or other parties) can also invest in limiting factors projects, which are usually small scale investments that increase specific corridors capacities. On the basis of these investments the TOs are allocated incremental FTRs, which give them access to the congestions surplus. As such, these projects can be classified as pure merchant. However, they represent a very small percentage of the overall transmission investment.

Assessment

The primary driver for transmission investment has been reliability criteria (both FERC and PJM-specific). Although PJM has an economic planning process, this protocol has not resulted in any substantial investment [74].

A key lesson from PJM is on the inability for merchant and regulated investments to co-exist efficiently, without a beneficiary pays cost allocation process, which PJM does not have. On the one hand, merchant investments are “economically-driven” and on the other hand, regulated investments are “security-driven”. Due to the wider benefit effect, regulated investors are guaranteed a return on their investment independent of asset utilization.

Few merchant projects exist in PJM, and they are mostly concentrated around the system extremities, taking advantage of arbitrage opportunities due to “seams issues” with neighbouring jurisdictions. The primary reason for this lack of merchant investment is that the efficient short-run system operation leaves little room for profitable projects within PJM. However, another important reason, is that regulated investments pose a significant risk to commercial projects. There is a real danger that a new regulated line lowers the price differential between two areas (by creating a parallel path flow) and damages the merchant project’s revenue model. It follows that private investors cannot manage this risk when it comes to potential reliability-driven projects mandated by PJM, severely limiting the attractiveness of such investment opportunities.

D. LESSONS FROM OTHER SECTORS

As part of the ITPR project we held a workshop in December 2012 to try to learn lessons from other network industries on how they dealt with transmission planning issues. This Appendix reviews the main conclusions from the workshop (with acknowledgement to those who participated).

The commonalities of network industries are summarised as follows:

1. The key questions are the same: how do we decide on network investment? how do we deliver it at least cost?
2. They each have multiple investment regimes where small investments may be assessed differently to larger ones.
3. They suffer from an inability to implement a spatially (and temporally) differentiated charging regime which would better signal the value of new investment (e.g. short term nodal prices).
4. There is a reluctance to target charging on beneficiaries which would facilitate the creation of a sensible demand side for investments.
5. They all have government targets which drive investment and face the need to make socially (rather than economically) motivated investments.
6. EU legislation tends to limit flexibility on the introduction of more competitive charging, in particular by a general tendency – in rail, telecoms and energy - to specify that network access pricing should be cost reflective (this limits congestion charging, efficient price discrimination and recovery of lumpy investments).

Lessons from Airports

The introduction of a constructive engagement (CE) approach by the CAA [75] since 2005 has been a key development. Under this approach a negotiation takes place at each regulated airport between the airport and its users (the airlines) as an important input into the periodic price review. The areas covered are substantial and are illustrated below. They arose precisely because of the perceived inability of the regulator to evaluate the proposals of the regulated firm in a conventional bilateral regulatory negotiation.

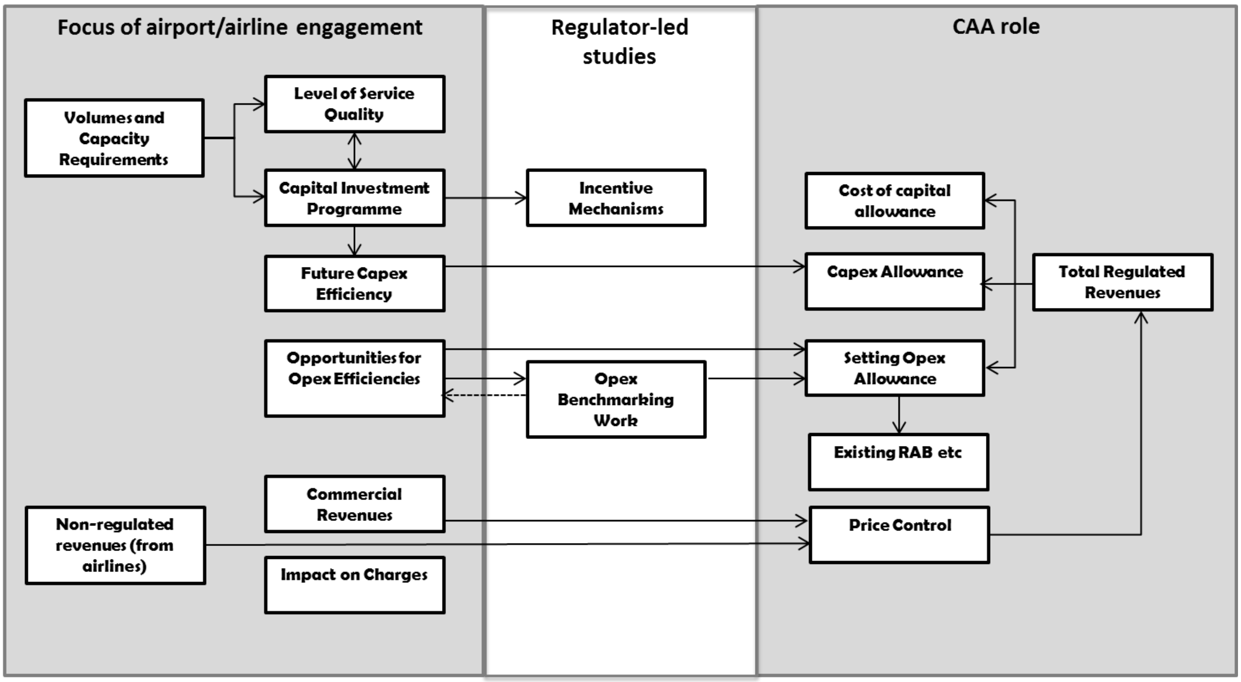

Figure 14: Illustrative CE process with RAV based approach, Source: [75]

This process seems to work, though in unexpected ways. At Heathrow, a Joint Steering Team (JST) - involving 25 representatives from 92 airlines - has recently reached agreement on 4 of the 6 elements of the CE approach above as part of the 2013-18 price control period. This included agreement on around 2/3 of the proposed investment programme at the airport (with the airlines wanting more!). CE is facilitated in airports because investment beneficiaries tend to pay. CE has been time consuming and lengthens the price control review process. CE was initially criticised because of the failure to reach agreement on investment requirements at Stansted in 2005, with an impasse between BAA and at least some of the airlines over the scale of investment requirements. However with hindsight this reflected the fact that 'do nothing' in the event of a failure to agree was not a credible threat for the negotiating parties (this is the default position in US regulation). A key part of the negotiation on investment is about agreement on 'triggers' and 'floors', i.e. what developments in demand would lead to the commencement or abandonment of planned investment. While agreement on the quantity of investment is the most contentious issue in the negotiations, agreement on other issues such as service quality targets and operational efficiency targets seems to have been much less difficult.

Lessons from Rail (both overground and underground)

Railways are a heavily subsidised industry. National rail receives around £4bn of taxpayer subsidy per year and passenger revenue of around £7.5bn. This subsidy level is a similar level to the costs of energy and climate polices charged to electricity and gas customers [76]. A key lesson from railways with regard to network expenditure is the clear definitions of the role of central government (strategy) and the rail regulator (delivery). Primary legislation enshrines two key concepts which 'keep ministers honest' in the sense of preventing them loading requirements on to private parties in the industry in lieu of taxation. In each regulatory period there must be a High Level Output Specification (HLOS) and a Statement of Funds Available (SoFA) from government. This provides the investment framework under which the industry can then be regulated. HLOS sets overall performance targets for the industry. The regulator then reports to government what investments can be afforded given HLOS and SoFA, allowing choices to be made. Recent developments are around the devolution of transport policy to local authorities, for the example 33 local authorities have formed the Northern Hub to develop rail links across their region.

Lessons from Telecoms

Telecoms is often thought of as the quintessential competitive network industry. However this is only partially true. Until quite recently (1991) network planning remained a preserve of BT. EU policy has favoured local loop unbundling (LLU), following Germany in 2000. The evidence is that end to end competition (cable vs fixed line) is better for investment but LLU does seem to have improved the quality of broadband services [77]. BT still has a monopoly of fibre investment in the UK and there is a clear problem in getting fibre to the home (FTTH) investments to take place in the current market. Australia is currently building a next generation National Broadband Network with 27bn ASD of public money via publicly owned company. According to Martin Cave, investment does occur in fixed line when: the price of copper is high enough to retail customers; access pricing is on retail minus regime (rather than cost plus); public finance is available to complete roll out; the regime is stable with fixed targets (e.g. EU broadband targets for 2020: 100% with +30MBps, 50% with +100MBps). In the UK, BT is now going for the cheaper fibre to the curb option, rather than fibre to the home, limiting its investment risk to only £2-3bn. What is striking about telecoms is that there are targets for broadband penetration, which look very similar to renewables targets (i.e. very ambitious) and that investment to achieve them may need some public support. However it is important to note that there is a tolerance of multiple investment regimes and that international interconnections remain very competitive.

Lessons from Oil and Gas pipelines

Stephen Littlechild has worked extensively on the lessons from North American negotiated settlements and their possible application to the UK. Negotiated settlements are a form of constructive engagement between the buyers and sellers of network services where they agree to given set of network charges in return for capacity and service quality. This settlement can then be signed off by the regulator under an administrative law process which merely checks that due process has been followed. Some of the earliest examples (from 1985) of these were for energy pipelines, including those regulated by the National Energy Board (NEB) in Canada [78]. The NEB (and many other regulators in North America) were overwhelmed by their caseload - prior to accepting negotiated settlements as an alternative to a full blown regulatory review. Why do negotiated settlements seem to work?

a. The regulator has to be removed as a provider of subsidy and zero sum elements. Thus in North America subsidy levels are not decided by the regulator, while zero sum such as the regulatory cost of capital must be pre-determined (and were each year by the NEB).
b. North American regulators are relatively small and don't do much actual analysis. A key problem in the UK is the tendency to have large, apparently sophisticated economic regulators. The evidence [79] is that lawyers tend to make better regulators anyway! This creates a tendency to think that regulators know best in the UK.
c. North American regulators recognised that they were the bottleneck in investment decision making and lacked the ability to analyse all the proposals put forward by the companies. This is increasingly the case in the UK. (The emergence of ISOs as private co-ordination entities shows how industries can self-organise regulation).
d. Collusion between the parties is an issue, but it does not seem to have been a major one in North America. This is an issue for a sophisticated competition authority.

e. Beneficiaries of investments pay, thus facilitating sensible negotiations by network users.

Some final observations from across the sectors

Network Investment Planning needs a clear process by which it occurs. Airports and Oil and Gas pipelines clearly illustrate the value of a serious and formal role for network users to engage with network providers. North America illustrates how this can work in a much more decentralised way than under Constructive Engagement, with self-organising industry engagement. The UK will be slow to accept that appealing to the regulator is not a default option, in the absence of a credible non-agreement threat. Both CE and negotiated settlements are facilitated by the assignment of costs in line with benefits, emphasising the importance of charging methodologies. Railways suggest the importance of clarifying the amount of subsidy available at the start of the regulatory review period and any government objectives for the industry. How this would work in energy would be complicated because the targets are mostly around generation (with implications for networks), but this now seems an obvious way forward. The HLOS and SoFA concepts could be translated into the relationship between DECC and Ofgem. Finally, telecoms offers a warning that some targets may require direct subsidy via public investment / public ownership, even when a private process can handle most investment.

E. ISO OWNERSHIP AND GOVERNANCE

This Appendix reviews the ownership and governance arrangements of Independent System Operators around the world drawing some conclusions that are relevant for evaluating the GB ISO option.

Ownership

As explained in [80] international experience suggests that ISOs should be a not-for-profit entity. The very few attempts of establishing a for profit ISO to date have been unsuccessful and either the decisions were reversed or not implemented due to high costs. The main arguments for that are that it is difficult to maintain a for-profit entity that is at the same time independent. In addition, ISOs are asset light and creating powerful incentive schemes can be very difficult. This means that the financial penalties that can be imposed on them for underperformance may be very low in relation to the size of negative effects that under-performance can impose on the whole market (e.g. in the event of a failure to prevent an area wide blackout[26]). This is especially true given the very wide mandate that most ISOs have and the difficulty in defining their output.

With respect to the ownership of not-for-profit ISOs, international experience suggests that there are two broad options; either the ISO is a government owned entity or it is membership based, with members representing industry stakeholders and governmental bodies. In the case of a members organisation, the representation between industry and government differs by country and ranging from 60% government members to as little as 20% or zero, as summarised in

Table 17.

In the absence of efficient transmission pricing and the limited exposure of market participants to investment and operational costs, as is currently the case in GB, it seems that it would be more appropriate for the ISO either to be a public entity or have a minority representation of industry stakeholders so as to ensure independence.

ISO funding methodologies vary significantly (as Table 18 indicates) and there does not seem to be a golden rule, either than the fact that the tariffs that the ISO administers should adhere to the beneficiary pays principle, which to date has had very limited practical application.

In the case of GB, there is does not seem to be an overarching reason to change the current cost recovery mechanism through BSUoS charges, subject to regulatory approval. Since the ISO would not invest in any assets the level of annual costs is expected to be similar to the current NETSO costs. Nonetheless, in order for the ISO to be able to strike contracts cheaply it is desirable that its credit will be provided by the government, through guarantees for cost recovery.

Table 17: ISO Ownership Paradigms [80]

ISO	*Mean annual load (GWh)*	*Installed generation (MW)*	*Transmission Lines (miles)*	*Population served (millions)*	*Ownership structure*
AEMO (Australia)	205,700 (2009)	48,600	24,854.8	21.9	60% government members and 40% industry

[26] *However this is also probably the case for a TSO and in most cases any penalties for poor performance need to be significantly capped*

					members
AESO (Canada)	69,904 (2009)	12,900	13,049	3.7	Statutory (public) corporation
CAISO (US)	229,857	57,124	25,526	30	Public benefit corporation
CAMMESA (Argentina)	111,333 (2009)	27,000	7,365	40.3	80% owned by Market Participants, 20% by the public ministry.
EirGrid (Ireland)	27,000 (2009)	6,246 (2009)	4,038.9	4.45	Public
ERCOT (US)	308,278 (2009)	88,227	40,327	22	Membership based non-profit corporation
IESO (Canada)	158,900 (2009)	34,557	18,160	13	Not-for-profit,non-taxable statutory corporation
ISO-NE (US)	126,842 (2009)	33,700	8,130	14	Public (limited liability, non-stock company incorporated in the state of Delaware)
MISO (US)	553,815	144,132	55,090	43	Non-profit, member-based organization
NYISO (US)	160,487	40,685	10,893	19	Public (Incorporated in the State of New York, not for profit organization)
ONS (Brazil)	1,573,438 (2009)	96,600 (2007)	N/A	193.7*	Private (not for profit, member based)
PJM (US)	420,837	164,895	56,499	51	Public (limited liability, non-stock company incorporated in the state of Delaware)

Table 18: ISO Revenue Recovery Paradigms [81]

ISO	*ISO Revenue Recovery System*
AESO (Canada)	The regulator determines the allocations of transmission system costs, and most are charged to distribution utilities and industrial customers, based on their use of system. Transmission facilities are owned by TFO (transmission facility owners), and TFO costs + planning and operating are recovered through transmission charges paid by electricity consumers. Generators' pay for transmission system losses. Utilities and industrial customers pay for transmission system costs. Consumers pay for assets, planning and operating (transmission charge). Generators pay for system

	losses. "The AESO recovers the costs of operating the real-time energy market through an energy market trading charge on all megawatt hours traded. The energy market trading charge is set to recover the operating costs and the amortization of intangible and capital assets and the AUC administrative fee during the period. For 2009, the AESO's component of the energy market trading charge is 23.2 cents per MWh to cover operating, intangible and capital costs (13.1 cents per MWh) and the AUC administrative fee (10.1 cents per MWh). For 2008, the AESO's component of the energy market trading charge was 11.1cents per MWh. There is also a component in the energy market trading charge that relates to the operations of the Market Surveillance Administrator (MSA), which is independent of AESO operations." Source: http://www.aeso.ca/downloads/AESO_Final_LR.pdf, http://www.aeso.ca/downloads/AESO_2009_AR_For_Web.pdf
AEMO (Australia)	AEMO fees are regulated market fees that are charged by AEMO to operate and administer the National Electricity Market (NEM). Charges for Renewable Energy Certificates (RECs) cover the retailer's costs in purchasing mandatory RECs. Both AEMO fees and REC charges are paid by the retailers. AEMO fees are passed on to customers at cost; REC charges can be negotiated with your retailer. Source: http://www.power.tas.gov.au/domino/power.nsf/v--ufactsheets/Understanding+the+Charges+on+your+Electricity+Bill/$file/Fact-sheet-11-Understanding-thecharges-on-your-ElectricityBill.pdf
CAISO (US)	CAISO is funded through rates it charges users of the California transmission grid and CAISO services, via its Grid Management Charge (GMC). The GMC imposes different rates for various services. Currently, a revision of the GMC is being discussed, following a cost of service study, due to the redesign of the wholesale market, MRTU with the launch of the nodal market in 2009 and the implementation of convergence bidding, and the recent move toward charging uses based on their actual consumption of given products and services. "The ISO's existing GMC contains seven GMC components and 15 separate charge codes. It has been largely unchanged since 2004 and was based on a FERC-approved settlement agreement with stakeholders" Source: http://www.platts.com/RSSFeedDetailedNews/RSSFeed/ElectricPower/6512357; http://www.caiso.com/docs/2002/08/02/2002080216283419989.html
EirGrid (Ireland)	Most of EirGrid revenue comes from regulated tariffs based on use of the transmission system. Group's revenue (SEMO, single market operator, the joint venture between Eigrid and SONI) is primarily derived from regulated tariffs, specifically the Transmission Use of System (TUoS) tariff, a charge payable by all users of the transmission systems and its share of tariffs as Market Operator for SEM. Source: http://www.eirgrid.com/media/Annual%20Report%202009.pdf
ERCOT	ERCOT (US) Rolled into costs that all ratepayers pay, « Postage-stamp »

(US)	transmission rate (same for everybody). Relative to electric bills, transmission and distribution represent around 17%; and ERCOT fee + nodal surcharge + NERC fee represents around 1%. ERCOT fee represents 98% of ERCOT's total base operating revenue requirement. Nodal surcharge is an additional revenue collected by ERCOT to recover costs to implement a nodal market as mandated by the PUC. The fee is assessed on wholesale energy transactions and becomes part of the overall cost of electricity. The fee does not appear on residential customer bills; however, if it were passed directly through to the end-use customer, it would average about 42 cents per month, or $5 per year, based on 1,000 kilowatt-hour usage per month. ERCOT is changing the way that it manages how power is bought and sold in the wholesale electricity market to make it more efficient and transparent. These improvements, called the nodal wholesale market redesign, are also funded by an ERCOT fee and account for nearly half of the annual fee costing residential electric consumers approximately 38 cents per month, or $4.80 annually. Source: http://www.ercot.com/content/news/presentations/2010/ERCOT%20Board%20Orientation.pdf, p.50
MISO (US)	MISO (US) Actual costs to provide services are recovered pursuant to a FERC accepted tariff: Schedule 10 of the tariff recovers the cost of transmission service and reliability coordination. Schedule 16 recovers the cost of the FTR market. Schedule 17 recovers the cost of the day-ahead and real-time energy markets. Source: http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-03829518EBD%7D/CorporateFactSheet101110.pdf
NYISO (US)	NYISO (US) NYISO Cost of Operation is a flat per MW fee to cover the cost of operating the NYISO. Source: http://www.nyiso.com/public/about_nyiso/understanding_the_markets/cost_of_electricity/index.jsp
PJM (US)	PJM (US) "PJM recovers its administrative expenses through stated rates applicable to market participants' transaction volumes, such as megawatt hours of load served, generation sold, and FTRs held. PJM is not authorized to charge its members rates higher than these stated rates without a FERC-approved rate filing. So, the stated rates act has long-term ceilings. (…) if PJM's actual costs are less than the revenues resulting from the application of the stated rates, then PJM refunds the difference to members on a quarterly basis." Source: http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/2010%20ISORTO%20Metrics%20Report.pdf

SPP (US)	SPP (US) SPP administrative charges are recovered under SPP Schedule 1A. This is a single rate for all services, which aims at recovering 100% of expected costs in fiscal year, is based on budgeted cash costs and forecast load and is established annually by Board of Directors. "The schedule 1-A administrative fee cap was set at 15¢/MWh when the tariff was implemented. This cap was raised to 20¢/MWh in April 2000 and then raised to 22.5¢/MWh in 2007". Source: http://www.spp.org/publications/FC070910.pdf

Governance

In [80] it is explained that the independence issue has focussed on the board of directors of the ISO given its separate legal status and its not-for-profit nature. An early paper [82] noted that a two tier board seems to be a good way forward, with an advisory board representing the interests and expertise of participating companies, subservient to a managing board made up of independents, whose competence and independence is crucial. In the US several ISOs have fully independent boards with no on-going relationships with market participants. It might also be desirable to have an independent market surveillance committee made up of academics although this might be problematic. In any case, this topic seems to be an evolving area, in line with general trends in corporate governance to seek more independent directors. The following table summarises the ISO board structure and selection process in different jurisdictions:

Table 19: ISO Board Structure and Selection Process Paradigms [81]

ISO	*Board Structure and Selection Process*
AESO (Canada)	AESO is governed by an independent board. Notes: "AESO Board must, as required by the Act, recommend to the Minister the appointment of an individual to the position of Member, including the re-appointment of a Member, subject, inter alia, to the following criteria and process: (i) such individual is in the opinion of the AESO Board, qualified pursuant to subsection 8(1) of the Act; and (ii) the steps taken to identify each such individual are taken in accordance with a recruitment process established by the AESO Board or any applicable legislation." The board is actively involved in the strategic planning process and discusses and reviews all materials relating to the strategic plan with management. At least one Board meeting per year is devoted to discussing and considering the strategic plan. On an ongoing basis, the AESO Board is involved in the financial oversight of all corporate operations, including cost and risk management. It has two standing committees: (1) the Audit Committee and the (2) Human Resources, Compensation and Governance Committee. Source: http://www.aeso.ca/ourcompany/board.html; http://www.aeso.ca/downloads/AESO_ByLaws_8_Sept_2010.pdf
AEMO (Australia)	AEMO Board currently comprises 9 skills-based non-Executive Directors and the Chief Executive Officer, from a minimum of 5 and a maximum of 10 Directors. The majority of Directors must be Independent Directors. "A minimum of three Directors and a maximum of six non-executive. The Directors must have Industry Experience. A person may not simultaneously hold office as both the Chairman and the Managing Director. (Clauses 7.1 and 7.2 of the

	Constitution). The Directors, other than the Managing Director, are appointed by a determination of the members of the Ministerial Council on Energy in accordance with the MCE Protocol and the Constitution. To assist it with making appointments, the Ministerial Council on Energy receives submissions from the Board Selection Panel and, in certain circumstances, the Chairman. Board Selection Panel, which is created by the Ministerial Council on Energy, must prepare a report specifying the candidates that the Board Selection Panel recommends for appointment as a Director. The report must first be approved by a resolution of Members before being submitted to the Ministerial Council on Energy. The Chairman will review all Directors whose terms are due to expire, and will compile a list of all such Directors who are eligible and whom the Chairman recommends be appointed for a further term. If the list includes all Directors whose term is due to expire, and the Chairman determines that there are no other vacancies in offices as a Director that should be filled, then the Chairman will present the list to Members for approval. If this list is approved, the list will be submitted to the Ministerial Council on Energy. (Clauses 7.3 and 7.4 of the Constitution)." Source: http://www.aemo.com.au/corporate/0000-0162.pdf
CAISO (US)	CAISO Board consists of 5 Governors nominated by the Governor of California and confirmed by the Senate. They serve staggered three-year terms. "The Board selection process involving stakeholders was outlined in a FERC order issued July 1, 2005. The Board Nominee Review Committee is comprised of six stakeholders from each of the following member-class sectors: transmission owners, transmission-dependent utilities, public interest groups, end-users and retail energy providers, alternative energy providers, and generators and marketers. Each sector is responsible for selecting its own six members to serve on the committee. Typically, the Committee becomes active beginning late summer each year. Once the Committee has been established and secretaries nominated, the Board member selection process proceeds as follows: • An independent search firm creates a list of at least four qualified candidates for each open seat on the Board. • The list of qualified candidates is then forwarded to the 36-member Board Nominee Review Committee. • Each member-class sector will select one person to represent the group to conduct a personal interview of selected candidates. • Based on inputs from the member-class sectors, recommendations are submitted to the Office of the Governor for the State of California." Source: http://www.caiso.com/282e/282eb6c881c0.pdf
EirGrid (Ireland)	EirGrid is governed by an independent 11-members Board, appoint by Government, and not subject to re-election.. Note: The Group is also compliant with the Revised Code issued by the Government on 15 June 2009. The Group also complies with the corporate governance and other obligations imposed by the Ethics in Public Office Act, 1995 and the Standards in Public Office Act, 2001, as well as, as far as possible, and on a voluntary basis, with the principles of the Combined Code of Corporate Governance ('the Combined Code'). The Group has implemented as appropriate the relevant principles of the Combined Code with the following exceptions: it is accountable to the Minister for Communications, Energy and Natural Resources; appointments to the Board are a matter for Government and accordingly the Group does not have a Nomination

	Committee; Board members are appointed by Government and, therefore, are not subject to re-election to the Board; the Group's policy in relation to the remuneration of the Chief Executive is in accordance with "Arrangements for determining the remuneration of Chief Executives of Commercial State Bodies under the aegis of the Department of Public Enterprise" issued in July 1999; and it is the opinion of the Board that the appointment of a Senior Independent Director would not be appropriate in the context of the membership of the Board. The Directors of the Board and Managers including all staff members are required to disclose any direct or indirect interest which could materially influence them in the performance of their EirGrid functions upon becoming aware of it. Source: http://www.eirgrid.com/media/EirGrid%27s%20Code%20of%20Business%20Conduct%20for%20Directors%20_CER%20Approved%2015%20Mar%202010_.pdf; http://www.eirgrid.com/media/Annual%20Report%202009.pdf
ERCOT (US)	ERCOT Board of Directors is a 16-member "hybrid" group that includes: 6 market participants from each of the six electric utility market groups investor-owned utilities (or transmission owners), municipally owned utilities, cooperatives, generators, power marketers and retail electric providers; 3 consumer representatives; 5 independent (unaffiliated) members, the ERCOT CEO; Texas PUCT chair (non-voting). Notes: Two third majority vote is required to take action. "The Technical Advisory Committee (TAC) makes policy recommendations to the board of directors. TAC is assisted by five standing subcommittees, as well as numerous workgroups and task forces. The Board also oversees the affairs of the Texas Regional Entity (Texas RE), the independent division that the Federal Energy Regulatory Commission established in 2006 to serve as the regional entity for the ERCOT region. Under the Board's oversight, ERCOT's stakeholder process is responsible for developing policies, procedures, and guidelines for power grid coordination, reliability, and market operations." "The Board (…) has general overall responsibility for managing the affairs of ERCOT, including approval of the budget and capital spending priorities, approval of revisions to ERCOT protocols and guides, and endorsement of major new transmission recommendations." Source: http://www.ercot.com/content/news/presentations/2010/ERCOT%20Board%20Orientation.pdf http://www.ercot.com/content/news/presentations/2010/2009%20ERCOT%20Annual%20Report.pdf
MISO (US)	MISO Board of Directors is an independent member group that includes seven members, plus the President and Chief Executive Officer ("CEO"). Each member serves a rolling, three-year term, and must meet specific qualifications designed to ensure an independent and qualified Board. "The CEO is a permanent member of the Board, who may vote on any matter presented at a Board meeting except when the CEO's vote would create a tied Board vote. In that circumstance, the CEO shall be barred from voting. The CEO is a non-voting, ex officio member of all standing committees of the Midwest ISO Board." Four of the directors shall have expertise and experience in corporate leadership at the senior management or board of directors level, or in the professional disciplines of finance, accounting, engineering, or utility laws and regulation. Of the other three Directors, one shall have expertise and experience in the operation of electric transmission systems, one shall have

	expertise and experience in the planning of electric transmission systems, and one shall have expertise and experience in commercial markets and trading, and associated risk management. "The Board of Directors is responsible for nominating Directors, who will be elected by the Members (…) Directors are not and have not been at any time within two years prior to their election to the Board either a director, officer or employee of a member, user or an affiliate of a member or user. (…) have no material business relationship or other affiliation with any member, user or an affiliate of a member or user while serving on the Board. [and are] prevent[ed] from having a direct financial interest in or a conflict of interest with any member, user or an affiliate of any member or user." (…) "A Director's participation in a pension plan of a Member or User, or an affiliate thereof shall not be deemed to be a material business relationship as long as such pension plan is a defined benefit pension plan that does not involve ownership of the securities of the company sponsoring such plan." Source:https://www.midwestiso.org/Library/Repository/Meeting%20Material/Company/Principles%20of%20Corporate%20Governance.pdf, http://www.midwestmarket.org/publish/Document/318dd6_119ce883271_-7ce00a48324a/Principles%20of%20Corporate%20Governance%20as%20adopted%2006-17-10.pdf?action=download&_property=Attachment
NYISO (US)	NYISO Board of Directors is a 10-member independent group, which includes the NYISO President & CEO and members with backgrounds in the electric power industry, finance, academics, technology, communications, and the law. Its members have no business, financial, operating or other direct relationship to any Market Participant or stakeholder. Source: http://www.nyiso.com/public/about_nyiso/nyisoataglance/board/index.jsp
ONS (Brazil)	ONS Board is composed of a General Director and four Directors of recognized competence in their area, elected by the General Assembly, being three members appointed by the Ministers of Mines End energy and two by agents. Note: It is the Board's responsibility to take whatever action necessary to run ONS, elaborate and propose Grid Procedures, perform all the duties of a technical character set in the Grid Procedures, prepare annual budget, prepare the Management Report and Financial Statements, among other duties. Source: http://www.ons.org.br/institucional/o_que_e_o_ons.aspx
PJM (US)	PJM Board of Directors is a 10-members independent group. The members may have no personal affiliation or ongoing professional relationship with, or any financial stake in, any PJM market participant. Note: PJM Board are responsible "for maintaining PJM's independence and for ensuring that PJM maintains the reliability of the power grid and operates a robust, competitive and non-discriminatory electric power market, preventing any market participants from having undue influence over the operation of PJM. To establish PJM's neutrality, Board members must adhere to a code of conduct." (…) "All communications received by the Board are handled in accordance with the rules relating to "ex parte" communications as outlined in the Code of Conduct. Written communication to members of the PJM Board are reviewed by an appointed staff liaison to the Board to ensure prompt disclosure of any "ex parte" communication in accordance with the Code of Conduct."

	Source :http://www.pjm-miso.com/about/board-managers.html
SPP (US)	"The Board of Directors shall consist of seven persons. The seven directors shall be independent of any Member; one director shall be the President of SPP. A Director shall not be limited in the number of terms he/she may serve. The President shall be excluded from voting on business related to the office of President or the incumbent of that office. No other Staff member shall be permitted to serve as a director." (…) "Directors shall not be a director, officer, or employee of, and shall have no direct business relationship, financial interest in, or other affiliation with, a Member or customer of services provided by SPP. (…) "Except for the President, a director shall be elected at the meeting of Members to a three-year term commencing upon election and continuing until his/her duly elected successor takes office. The election process shall be as follows: (a) At least 90 calendar days prior (…) election (…), the Corporate Governance Committee shall commence the process to nominate persons equal in number to the directors to be elected; (b) At least 45 calendar days prior (…), the Corporate Governance Committee shall determine the persons it nominates (…); Source: http://www.spp.org/publications/Current%20Bylaws%20and%20Membership%20Agreement%20Tariff.pdf

In addition to the board structure and its independence, a key criticism of ISOs is whether they are bureaucracies with inherent incentives for:

- risk-aversion and thus conservative system operation and planning;
- ever-expanding area of influence and undertaking activities for which others pay; and
- costs proliferation.

The reality is that US ISO costs and scope in US have been increasing but it is unclear whether this has been due to bureaucratic tendencies or because it has been efficient to gradually increase the responsibilities of ISOs and consequently their size and costs. In [80] some costs of three US ISOs with those of National Grid are compared and it is found that the ISO costs are 2.5-4 times higher than the equivalent of NGET on a population served basis. Although it is unclear whether these differences represent some other industry related issues it does show that some ISOs can be more cost efficient than others. In addition, the efficiency differences might also reflect the ability of respective regulators to control costs, highlighting the importance of a strong regulator. Indicative annual costs for a number of US ISOs are presented in Table 20.

Table 20: US ISO Annual Budgets 2010 [81]

ISO	*Annual Budget ($mn)*	*Staff*	*Peak Demand (MW)*
CAISO (US)	195	572	57,000
ERCOT (US)	176	670	65,700
MISO (US)	273	782	137,000
NYISO (US)	119	452	33,000

PJM (US)	252	725	167,000
SPP (US)	76	476	50,000

Overall, the operation costs of an ISO represent only a fraction of the total system costs and would probably be more than self-funding should modest transmission investment and operation efficiencies are achieved. This was also a key message for the International Workshop participants from the US, explaining that a single contribution from PJM ISO could justify any cost inefficiencies since its operation. Given the level of transmission investment and expected congestion costs going forward there is ample scope for achieving such efficiencies.

Because of the non-profit nature of ISO, the most important criticism of this option is that its employees are likely to be risk averse and inadequately incentivised thus promoting conservative system planning and operational measures. With respect to incentivisation for efficient operation and planning, strong and long term managerial incentives could be potentially established, which on aggregate might be even more powerful and less costly than organisational incentives. To a certain degree experience for the California ISO (CAISO) is relevant. Nonetheless, the majority of the operations of the ISO would be based on following processes, applying grid codes and rules and supporting decision making through social welfare maximization CBA and not on incentives. Reviewing the list with the key ISO responsibilities, for the majority of the items it is evident that the actions are a matter of applying market codes and following processes. These rules could be reviewed periodically and if they prove to be inefficient, changed. Given that the ISO is not-for-profit it would welcome any rule changes that would increase its efficient operation as opposed to for profit organisations, who would fiercely oppose any changes that would alter their profit maximization functions.

What would be the biases of an ISO? The answer is that it would be transparent and focus on real time optimisation and be biased against unnecessary investments given that it would rather run the existing networks. This would seem to be a good thing and encouraging of smart solutions for expanding capacity. Indeed given the difficulty of building physical capacity generally an organisation that really sweated the existing assets is precisely what is necessary.

F. OVERVIEW OF INTERNATIONAL EXPERIENCES IN APPLICATION OF ADVANCED OPERATIONAL MEASURES AIMED AT ENHANCING THE UTILISATION OF EXISTING TRANSMISSION NETWORK

Over the last 20 years the development and application of advanced new network, information and communication technologies, including special protection schemes (SPS[27]), coordinated voltage control techniques[28], wide-area monitoring and control systems, advanced dynamic security assessment techniques, demand response (DR), and dynamic line rating (DLR), demonstrated that the latent transmission network capacity can be released to network users, postponing or even eliminating the need for asset-heavy network reinforcements, without compromising security of supply.

Since the 1990s, there have been a number of papers presented by practitioners (particularly at the last three CIGRE conferences) reporting successful and reliable operation with implementing non-network solutions, most of them employed to increase the existing transmission network capability and minimise costly reinforcement in countries such as Canada, Brazil, Sweden and Norway.

Recently, it has been demonstrated through several economic and technical studies that there is an array of non-network solutions based on advanced corrective control applications and operational measures that could significantly increase the levels of capacity released to network users in GB, especially between Scotland and England [83], [84].

In the following sections, various case studies are presented that illustrate the application of non-network solutions across a number of jurisdictions. In addition to discussing the benefits of non-network solutions, we also present at the end of this chapter a section with the current research on the risks associated with the proliferation of solutions based on smart grid technologies and advanced operational measures.

Norway

Statnett [86] has been using Special Protection Schemes combined with advanced probabilistic techniques to increase utilization of the existing transmission network. Various system protection schemes have increased transfer limits considerably within Norway and on the interconnections with Sweden, without deteriorating reliability and quality of supply. The use of probabilistic techniques and new technology (appropriate smart technology with phasor measurements and distributed local intelligence) have permitted operators to develop new rules for both planning and operation aiming at minimising costs, including interruptions. Temporary higher risk operation, like N-0-type network loads, is allowed as long as probable consequences are within defined limits.

It is envisaged that to augment the Norwegian transmission capacity in the years to come, heavy investments will be needed, but combined with the continued use of innovative methods to achieve high utilization of new as well as existing transmission assets.

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[27] *Special Protection Schemes is a protection scheme that is designed to detect a particular system condition that is known to cause unusual stress to the power system and to take some type of predetermined action to counteract the observed condition in a controlled manner. In some cases, SPSs are designed to detect a system condition that is known to cause instability, overload, or voltage collapse. The action prescribed may require the opening of one or more lines, tripping of generators, ramping of HVDC power transfers, intentional shedding of load, or other measures that will alleviate the problem of concern.*

[28] *Conventional voltage control is local not system wide; in other words control decisions regarding voltage regulation are traditionally based only on local measurements, which is sub-optimal and may limit the utilization of the network. Advanced area based voltage control can enhance the capability of existing networks.*

Sweden

A special protection scheme against long-term voltage collapse has been designed, implemented, and tested in the south part of the Swedish grid [87]. The protection scheme is developed within the present SCADA system, which has been complemented with input signals and equipment to execute action orders from the protection system. Bus voltages from the transmission system, reactive power output from generators connected to the transmission system, and current limiter information from main generators have been used as input signals to the special protection system. The action list from the protection system is comprehensive and includes: shunt reactor disconnection, shunt capacitor connection, start of gas turbines, emergency power request from the HVDC connection to Germany, low priority load disconnection and finally shedding of high priority load.

Itaipu (Brazil)

A number of Special Protection Schemes have been installed at Itaipu [88] since the beginning of the plant operation and have enhanced security to the system. The SPS have been mainly designed to maintain system stability and to avoid voltage and/or frequency collapse, and to act during complex problems in the interconnected system, with a few exceptions, in which the SPS also acts during 'simple' contingencies.

The SPS have had very good performance historically, minimising interruption of load and the occurrence of major blackouts throughout the Brazilian and Paraguayan power system. The mis-operations observed are associated with equipment maintenance and with failures of programmable logic controller (PLC) design or auxiliary equipment.

Hydro-Québec experience in SPS with advanced data mining

A new approach has been used by Hydro-Québec [85] to determine rules of automatic devices installed in its main power plants (for generation shedding) and to maintain secure operation under extreme contingencies through advanced data mining techniques. Data mining has been used for the rules of the automatic generator rejection and remote load shedding system, where real time snapshots of the Hydro-Québec power system collected over several years have been used to generate large amounts of results (database) by transient stability simulations. This approach gives the most relevant parameters and finds optimal settings, minimizing the number of generator rejection while maintaining the same performance in terms of security coverage. This approach has permitted planning engineers to propose new operation rules to optimise system operation.

Manitoba Hydro experience in SPS with coordinated AC/DC

An integrated AC/DC special protection scheme is used to maintain system stability in the Manitoba power system [89] following loss of any lines between the Manitoba region and U.S.A. The SPS is innovative and exploits the inherent controllability of HVDC to provide enhanced system stability and is a cost effective solution to facilitate higher export levels, which would be otherwise unattainable.

Triplication of the system has allowed the SPS to achieve a very high reliability level and at the same time allow regular maintenance to be performed without affecting the system operation.

Hydro-Québec experience in adaptive SPS

Hydro-Québec [91] has a significantly interconnected and heavily loaded transmission network, where a fast detection of topology change is critical when identifying and instigating set of remedial actions for the defence of the system against severe events. The remedial actions include fast generation and load shedding. The protection can detect the loss of a line in under 35 ms, using only the line voltages and currents at the local end. Power flows as low as 0.015 p.u. are detected. The logic/algorithms are intelligent, requiring only two settings in order to function: (1) The nominal rated power of the circuit, and (2) the nominal line charging current.

Memorised real and reactive power measurements are processed alongside slow rate of change of measurements, including shifting of the power factor, and fast (jump) rate of change in power (2nd order derivative). Monitoring of sequence components fine-tunes the accuracy and allows additional digital outputs to implement advanced and reliable SPS. After extensive laboratory and field tests, it was concluded that all typical network scenarios such as low/zero power transfer, high loading, current and power flow reversals, swings, resonance and harmonic conditions produce no spurious operation.

Adaptive techniques based on fuzzy logic are deployed. All of the investigations that the engineer would make are built into rules, each of which has a defined degree of confidence associated with it. The user does not need to program the rules, nor multiple analog setting thresholds, the fuzzy logic implementation is an intelligent approach and negates such traditional constraints. Being implemented in a numerical relay, this offers a set of flexible auxiliary functions for communication, programmable scheme logic, self-verification, event logging and disturbance recording to complement the protection algorithm.

This is clearly advanced SPS as the remedial actions taken automatically adapt to continuously changing system condition. The implemented SPS significantly enhances the utilisation of the existing transmission network.

Western North American power system experience in wide-area voltage control

The wide-area stability and voltage control system (WACS) in Western North American power system [92], [93] uses powerful discontinuous actions for power system stabilization. The control system comprises phasor measurements at many substations, fiber-optic communications, real-time deterministic computers, and transfer trip output signals to circuit breakers at many other substations and power plants.

The WACS exploit advances in digital/optical communications and computation. Specific advantages include the following:

- Control for outages and conditions not covered by feed-forward controls (SPS).
- Potentially simplifies operations for changing system conditions—currently, operators are required to reduce power transfers when unstudied conditions are encountered.
- Improved observability and controllability compared to local control. Discontinuous control reduces exposure to adverse interactions.
- Flexible, high reliability "open system" platform for rapid, low-cost control and monitoring additions, including wide-area continuous control.
- Provides a combination of reliability increase and power transfer capability increase.
- Caters to uncertainty in simulation results used to determine operating rules and limits.

- Future potential with cost reductions and further IT advances. Potential for application in meshed grid as well as intertie corridors. Control inputs and outputs may be extended over a larger geographical area such as the entire western North American power system.

Netherlands experience in Dynamic Line Rating (DLR) [94, 95]

Since spring 2005, a dynamic rating system monitors an transmission link in the 150 kV network near Amsterdam. This connection consists of an oil-filled power cable and an overhead line in series. By making optimal usage of the thermal capacitance of the underground cable environment as well as the variations in the weather for the overhead line, the dynamic rating system can be used to transport more load without exceeding the imposed temperature limits. Real-time inputs for the dynamic rating system are the circuit loading and the weather condition. The system calculates the existing temperatures in the link and the future loading possibilities. These future loading possibilities are calculated based on relevant failure scenarios.

The application of the DLR technology enables the system operator to enhance the utilisation of the network, particularly under outage condition. The grid operators are continuously informed about the loading capabilities of the connection. The connection can therefore be fully utilised in case of an emergency without risks that segments of the line may be overloaded. For the asset managers, the system also facilitates access to historic temperatures for remaining lifetime prediction purposes and for assessing the loading capability of the link.

Key experiences with the application of DLR technology include:

- Deploying dynamic rating systems enables increasing circuit loading without exceeding the thermal limits. With these systems, higher loads can be transported during emergency conditions and financial benefits may be gained by delaying investments and by planning maintenance periods efficiently;
- This particular dynamic rating system is based on dynamic models rather than on measurements. This is an advantage in the usability, reliability and costing of such systems;
- An in-depth site and soil survey was necessary to find the hotspot because no glass fibre was present in the transmission connection. For new cable systems one has the choice to integrate glass fibres against relatively low cost. Since glass fibres facilitate the finding of hotspots to a large extend, integrating glass fibres for temperature measurements in new connections is worthwhile.
- Creating a basis in the organisation for innovative techniques as dynamic rating systems needs broad appreciation.

Similar DLR schemes are used in other jurisdictions and are summarised in the table below:

Table 21: International Practice in Deploying DLR

Location	*Company*	*Monitors*	*System*
New Zealand	Transpower	2 tension	220kV
Tasmania (Australia)	Transend	15 weather & 19 tension	110kV
California (US)	PG&E	4 tension	230kV

Colorado (US)	NCE	2 tension & 3 temperature	230kV
W.Virginia (US)	Virginia Power	5 tension	500kV & 115kV
S. Louisiana (US)	Entergy	2 tension	230kV
Brazil	CEMIG	6 temperature	138kV
Chile	Pelambres	4 weather & 4 temperature	220kV

Experiences in smarter control rooms: online security assessment [96]

Traditionally, security has been achieved solely through off-line analyses using forecasted information. In the new environment, this approach has proven inadequate and often impractical. As a result, on-line dynamic security assessment (DSA) has emerged in which a snapshot of the current system is obtained and is used to conduct security assessment. This approach reduces the need for prediction of system conditions and therefore is expected to provide more accurate assessments. However, since all data must be assimilated in near-real-time, and computations must be conducted automatically with little or no human intervention (and in a tightly constrained cycle time), on-line DSA has many inherent challenges. Depending on the nature of a given system, the scope of DSA may be quite broad including transient security assessment (TSA), voltage security assessment (VSA), small signal security assessment (SSSA) and frequency security assessment (FSA).

Table 22: International Practice with Smarter Control Rooms [MB stands for Measurement Based]

Country/Location	*Location/Company/Project*	*Scope*			
		TSA	**VSA**	**SSSA**	**FSA**
Australia	**NEMMCO**	✓		✓ (MB)	✓
Bosnia - Herzegovia	**NOS**	✓	✓		
Brazil	**ONS**	✓	✓	✓	✓
Canada	**BCTC**	✓	✓		
Canada	**Hydro-Quebec**	✓	✓		
China	**Beijing Electric Power Corp.**	✓			
China	**CEPRI**	✓			
China	**Guangxi Electric Power Corp.**	✓		✓	✓
Finland	**Fingrid**		✓	✓ (MB)	
Greece	**Hellenic Power System**		✓		
Ireland	**ESB**	✓	✓		
Italy & Greece	**Omases Project**	✓	✓		
Japan	**TEPCO**	✓	✓		
Malaysia	**Tenaga Nasional Berhad**	✓	✓		
New Zealand	**Transpower**	✓	✓		

Panama	**ETESA**	✓	✓		
Romania	**Transelectrica**	✓	✓		
Russia	**Unified Electric Power System**	✓	✓		
Saudi Arabia	**SEC**	✓	✓		
South Africa	**ESKOM**	✓	✓		
USA	**PJM**	✓	✓	✓	
USA	**Southern Company**	✓			
USA	**Northern States Power**	✓			
USA	**MidWest ISO**		✓		
USA	**Entergy**		✓		
USA	**ERCOT**	✓	✓		
USA	**FirstEnergy**		✓		
USA	**BPA**		✓		
USA	**PG&E**		✓		
USA	**Southern Cal Edison**		✓		

From the international experiences summarised in the table, the functionality of the Brazilian control room is considered particularly advanced. Similarly, advanced applications are used in the control rooms of the power systems in New Zealand, China and PJM. At present, the Brazilian system is the only one that includes all these applications.

The number of on-line DSA installations around the world is continuously growing as system operators recognize that such approaches provide practical solutions for ensuring power system security and an optimum utilisation of the network assets.

A significant amount research and development is on-going in the field of on-line DSA; most of R&D activities are aimed at extending the features and capabilities of existing on-line DSA systems. Areas of work include handling of new technologies such as wind farms, improving speed and scope of assessments, improving visualization of results to operators, using optimisation in determination of remedial measures, and use of intelligent systems.

Experiences in using Phase Shifting Transformer (PST) for post-contingency control

USA Pacific Electric

Arrowhead station in USA Pacific Electric presents a non-standard equipment set composed of: phase shifting transformer, voltage regulating auto transformer, and shunt capacitors with fast and slow control [97].

One of the main characteristics of the phase shifting transformer is its ability to respond to outages through a post-contingency re-adjustment system and a remedial action system. These two allow respectively:

- Detecting a sudden large change in power flow and adjust taps so and as to partially counteract that increase in flow
- Quickly adjusts taps to drive system towards a more secure operating point

This is illustrated in the figure below where large increases in post-fault power transfers are detected and controlled (and brought back to the control band) by automatically changing several tap positions (e.g. 10) at once (one tap equals to one degree approximately –PST has 32 taps)

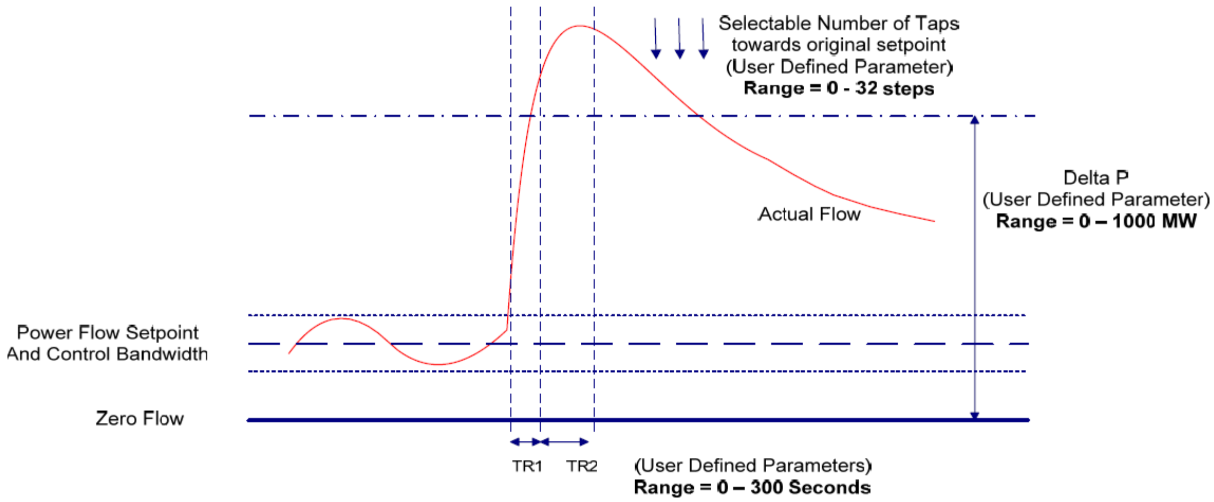

Figure 15: PST Re-adjustment system [97]

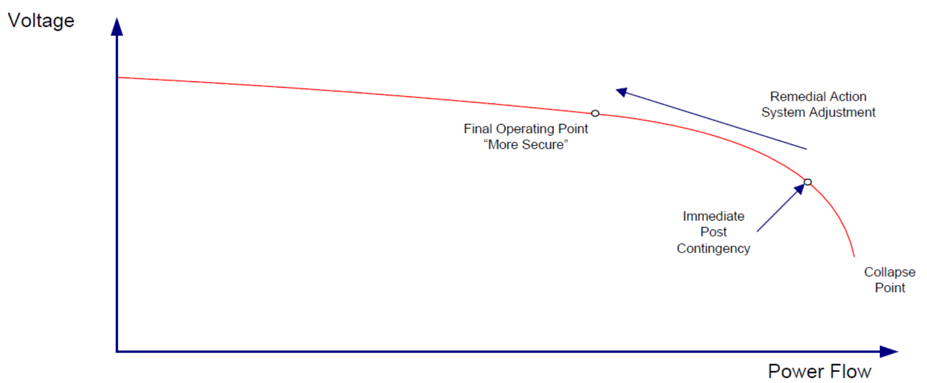

Figure 16: PST Remedial action system [97]

In addition, Arrowhead station contains 2x75MVar shunt capacitors (30K/31K) with fast control that permit, together with the above automatic reduction in power transfers, to control post-fault voltage drops by rapidly (in about 12 cycles after the voltage drops below 98%) connecting reactive compensation and hence move towards a more secure post-fault operating point with increased voltage and reduced flows (see figure below). This is also supported by capacitors held in reserve for contingency use in the neighbouring Stone Lake station.

<u>Italy</u>

In the European electricity system, the trading of electrical power over larger distances as well as the connection of new generation, especially wind power, create new load flow patterns that often challenge the security of the existing transmission network. In this context, an advanced PST is installed in the 380 kV Rondissone substation that allows the Italian system operator to manage the power flows in the neighbouring area [98]. The operational strategy of the PST needs to determine criteria for the control of the phase angle. The automatic tap changer controller allows different control modes: maintaining a remotely set power flow or remote control of the tap position. The insertion and de-insertion of the PST requires special switching sequences.

The PST rating is 1181 MVA and the maximum phase shift has been specified to be 15°, so as to enable the power system to remain stable after the loss of the double north line. An automatic controller will alter the phase shift according to the situation and the type of event occurring: in normal operating conditions, the phase angle will be set near to zero so as to avoid disturbances for the Italian TSO. The phase angle will be shifted to its maximum for the most severe contingency (loss of the double line). The scheme, consisting of a PST with a by – pass disconnector, allows:

- use of tap changer in real time;
- easy utilizations of the PST in the different conditions;
- a reasonable flexibility of operation.

Risks of application of advanced network technology and operational measures

Application of advanced network technologies and novel operational measures is growing. These measures have delivered technically feasible and economically efficient solutions to enhancing the capability of the existing transmission networks, especially in a system with increased penetration of renewable generation. In fact, in many jurisdictions these solutions enabled transmission reinforcement to be postponed while maximizing the utilisation of network capacity.

While the adoption of advanced network technologies is valuable for enhancing the utilisation of the existing network assets, it is also important to understand the risk profile of the network that operates with reduced security margins and relies on extensive corrective control. In fact, recent work conducted [99] points out that in case of extensive use of SPS, it is important to investigate consequences of inadvertent interactions among SPS. Furthermore, in [99] it is also mentioned that there is currently a lack of simulation and assessment tools that could capture such phenomenon and enable network planners to derive reliable options at the system planning stage.

The main conclusions of analysis conducted are:

1. SPS have been a major technological advancement that facilitates release of latent network capacity, and enhances the utilisation of existing network and resources and smooth interconnection of renewable generation.

2. SPS has proven to be greatly economical and easy to implement compared to transmission network reinforcement, and many utilities are favouring SPS to meet their generation and transmission expansion goals.

3. In North America, maintenance standards and accompanying documentation have been developed by network operators deploying SPS, to ensure compliance with NERC reliability standards. One of the prominent features of all standards has been the emphasis in embedding redundancy into SPS architectures, to ensure SPS operations are immune to failures and uncertainties.

4. The advent of synchrophasors (PMUs) has given a major boost to SPS's operational performance and has increased the range of SPS applications. SPS along with PMUs and PDCs (Phasor Data Concentrators) have been instrumental in advancing the Wide Area Monitoring, Protection and Control Systems (WAMPACS).

5. Power industry has seen a drastic proliferation in SPS, which is proving to offset the advantage these individual SPS brings in by causing coordination and maintenance issues. This has served as great motivation for industries to move from a localized-SPS to Centralized-SPS technology with the help of EMS and PMUs.

6. As the dependence on SPS is growing, there is a greater interest in building the knowledge base and expertise in understanding SPS operational performance and risks involved. Interestingly, this can be accomplished by extracting relevant standards and practices from existing industries. Safety instrument systems (SIS) of process control industry in one such example. The process of building operational rule for power system operators using stochastic tools and machine learning techniques is another example that could contribute in SPS logic derivation and evaluation.

7. In modern systems with significant penetration of SPS, inadvertent interactions among SPS may lead to cascading outages.

The above risks associated with malfunctions of advanced network technology and novel operational measures, however, should not utterly limit their use in maximising the utilisation of existing network capacity. For example, in [83] it is shown that the likelihood of having malfunctions in SPS has an inverse relationship with the amount of network utilisation as shown in Figure 17.

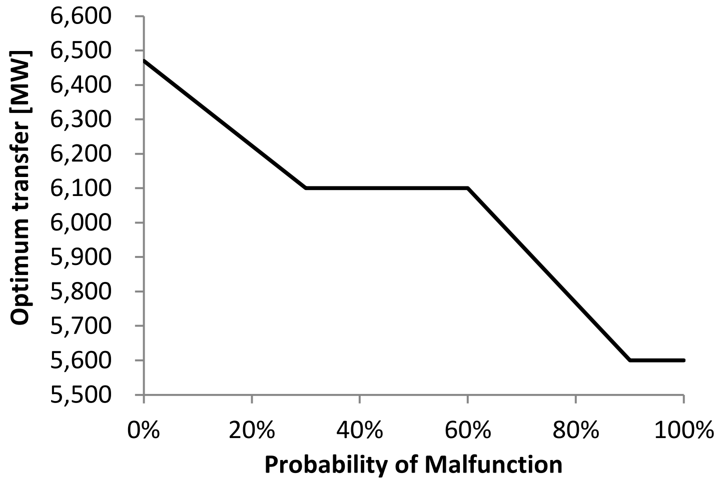

Figure 17: Optimum transfer when considering SPS malfunction events

Figure 17 illustrates that the optimum transfer in a 6.8 GW interconnector decreases from 6.5 GW to 5.6 GW when the probability of having a malfunction in the SPS equipment increases from 0% to 100%. Usually, 6.5 GW represent the maximum power that can be optimally transferred when considering the SPS fully reliable and the 5.6 GW represent the power that can be transferred when only preventive control is used (SPS not applied). Such approaches enable analysis of cost and benefits of different transfer levels to be established.

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