Ontario Energy Board

Staff Discussion Paper: Generation Connections

Transmission Connection Cost Responsibility Review

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I INTRODUCTION

Objective of this Consultation

On January 4, 2008, the Ontario Energy Board launched this consultation to examine its policies regarding cost responsibility for generation and load connections to transmission systems. The letter of January 4th invited parties to indicate their interest in the process and invited them to provide comments to facilitate framing of the issues. Approximately 53 organizations are registered participants in this consultation process and by mid-February the Board had received 11 written comments. A stakeholder meeting was held on February 14, 2008 at which Board staff and participants made presentations.

As indicated in the Board's letter of January 4, 2008, the Board is examining its transmission connection cost responsibility policies to ensure that those policies facilitate the rational and optimal development of transmission infrastructure in a manner that reflects the evolving needs of the electricity sector and the Province as a whole.

As also identified in the Board's January 4, 2008 letter, this consultation covers both generation and load connections. The concerns that have been raised to date in relation to these two types of connections are different, as are the underlying issues. For that reason, it is in Board staff's view more efficient to address them separately. This Discussion Paper addresses issues pertaining to generation connections. A separate staff Discussion Paper on issues pertaining to load connections will be issued at a later date.

Current Connection Process and Cost Responsibility Policy

The current connection process, and cost responsibility associated with investments in transmission infrastructure, are governed principally by the Board's Transmission System Code (the "TSC") and are also affected by the manner in which the different transmission cost pools (line connection, transformation connection, and network) are defined.[1]

[1] Appendix I contains a description of the different transmission cost pools.

The Board's current cost responsibility policy can be summarized in three points:

- Cost responsibility for customer-driven connection facilities should rest with the customer;
- This is also the case when the connection facilities are triggered by the needs of more than one customer; and
- There is an exception that applies where a connection facility was otherwise planned by the transmitter to meet load growth or maintain system reliability and integrity.

Two additional points are important:

- Generators are responsible for paying for and constructing their connections to the grid; and

- Transmitters are not permitted to construct generator connections to the grid.

Focus of Discussion Paper

One of the evolving needs identified by the Board in its January 4, 2008 letter is the government's expectations in relation to the development of renewable supply, as reflected in the "Supply Mix Directive" and other directives issued to the Ontario Power Authority ("OPA").

Increased investment in renewable forms of generation is reflected in the OPA's Integrated Power System Plan (the "IPSP") filed with the Board on August 29, 2007 (proceeding EB-2007-0707). Beyond that, the IPSP also contemplates "clusters" – geographically specific areas which appear to have good potential for development of wind and other renewable resources. These clusters are located at significant distances from the transmission grid and thus require relatively long transmission connection lines. The IPSP refers to these lines as "enabler lines" – dedicated radial transmission lines to connect clusters to the grid.[2]

Staff notes that the Board's initial communications in relation to this consultation did not narrowly define the scope of the initiative. Staff has come to the view, however, that it is appropriate that attention be focussed more specifically on issues associated with enabler lines. This view reflects research done since the commencement of this consultation; the comments and presentations prepared by stakeholders for the

[2] The OPA has identified ten such renewable resource clusters in the IPSP. For three of these clusters (near Goderich, on the Bruce Peninsula, and on Manitoulin Island), the IPSP also describes the associated enabler lines.

February 14, 2008 stakeholder meeting; and the absence of expressions of concern by stakeholders around generation connection policies in general.[3]

When the Transmission System Code was developed, it was contemplated that generators would consist principally of large, single proponents whose facilities would be located close to the grid. In that context, policies that call for generators to design, develop and construct their own connections to the grid independently of the transmitter, and to be responsible for the associated connection costs, can be expected to promote the rational and efficient expansion of the transmission system. This approach assigns connection cost responsibility to the entity that influences the costs. Generators have an incentive to balance the costs and benefits of connecting, and to pursue only those projects that exhibit net benefits.

The emerging issue in relation to enabler lines rests on the premise that the full resource potential from any given renewable resource cluster may well be represented by many different proponents each intending to exploit a portion of the zone's potential. Under these circumstances, the cost of connection to the grid could be very high with respect to the scale of any one proponent. Under existing policies, these connection costs would be borne by the generators, and co-ordinated action on the part of the proponents would be needed to minimize total connection costs and steer the projects through potentially lengthy and complex regulatory approval processes. However, multiple proponents may not be able to organize and coordinate themselves to achieve the "right-sized" connection to the grid, particularly if the process were to unfold independent of the transmitter as is currently the case.

II ENABLER LINE DEVELOPMENT: COMPARISON TO OTHER JURISDICTIONS

The issue of connecting clusters of remote renewable resources to the grid has arisen in other jurisdictions. This section discusses the approaches developed in California and in Texas, and compares these with current arrangements in Ontario.

[3] Indeed significant generator connection activities, including for renewables, have taken place in the past under the Board's existing policy framework. Over 400 MW has already been connected to the transmission system and a further 900 MW is expected to connect over the next few years. In several cases (for example, the Erie Shores Wind Farm) a single developer was able to get approval and construct connection facilities for multiple wind farms. However these connections have typically been shorter and less remote than the enabler lines proposed in the IPSP.

Enabler Line Development in California and Texas

With the assistance of Board staff's consultant, Power Advisory LLC, three other jurisdictions - California, Texas and the United Kingdom - were reviewed to examine both what their cost responsibility policies are and how they carry out the development of enabler lines and the associated renewable resources. The relevance of the UK example is limited because, unlike many other jurisdictions, including Ontario, generators are charged for the use of the transmission system. Texas and California more closely resemble Ontario's situation in that regard, and are the focus of the discussion below.

The following summary is provided for general context. A copy of the report prepared for Board staff by Power Advisory LLC is attached as Appendix II.

In Texas, legislation requires the regulator - the Public Utility Commission of Texas (the "PUCT") - to play a major role along with the system operator - the Electricity Reliability Council of Texas ("ERCOT") - in developing "Competitive Renewable Energy Zones" ("CREZ"). The PUCT instructed ERCOT to identify where the CREZs are, how big the potential resources are in each zone, and the size and cost of the potential lines to bring those resources from each zone to market. The regulator also runs a contest to determine who will be the "Transmission Service Provider" who will build the lines. Before proceeding, generators must make a deposit to ensure that they show up and use the transmission line capacity. Once the line is built and the generator connects to it, the deposit is returned. The costs of the CREZ facilities go into the transmission rate base. The level of transmission expenditure that could be put in the rate base is immense - from US$2.95 billion to US$6.38 billion worth of transmission to facilitate the connection of 12000 - 24000 MW of renewable generation[4]. In Ontario, by contrast, the capital cost of the three enabler lines identified in the current IPSP amounts to C$210 million to connect about 700 MW of renewable generation.

In California, a process to construct similar facilities, known there as "locationally constrained resource interconnection facilities" has been approved by the Federal Energy Regulatory Commission and incorporated into the transmission tariff. The California Energy Commission and the California Public Utilities Commission determine where the "Energy Resource Areas" are. The planning process through the system operator - the California Independent System Operator ("CAISO") - can identify where a "locationally constrained resource interconnection facility" ("LCRIF") could be located. The CAISO has a duty to co-ordinate and avoid duplication through its regional planning process. In this case, firm commitments by generators to pay a pro-rata share of the transmission facilities are needed for at least 25% of the line's capacity with evidence that at least a further 35% of the capacity is likely to be taken up. The transmitter develops the LCRIF.The generators are obliged to pay for their share of the actual costs of the facility. Costs not covered by generators are included in the transmission rate

[4] Included within these renewable generation capacity totals are 6,903 MW of existing wind generation or projects that had signed interconnection agreements.

base. As other generators join later, they pay a depreciated share of the transmission facility costs.

Each of the three jurisdictions reviewed have taken a different approach to the development of clusters of renewable resources in a competitive market context. One common conclusion feature is that *such approaches do more than address the question of "who pays"* but also address *process issues*. The following four elements seem common to the approaches in the other jurisdictions reviewed here:

i) The clusters/zones/resource areas need to be identified and approved.
ii) The appropriate size and location of the enabler facilities must be planned and be subject to some form of regulatory review.
iii) An entity responsible for ensuring co-ordinated development of the clusters and associated transmission has to be identified.
iv) Financial mechanisms for allocating risk and recovering costs of the transmission facilities have to be specified.

Ontario

This section examines the Ontario institutional context that is relevant to generation connections.

The OPA

Unlike the other jurisdictions identified above, Ontario has a hybrid market where a provincial agency, the OPA, plays a central role in both system planning and procuring new generation. The OPA has a statutory responsibility to develop an Integrated Power System Plan ("IPSP"). As noted above, the IPSP that is currently before the Board identifies the location of renewable resource-rich clusters, evaluates which of these clusters are economic to develop, and proposes when three such clusters should be developed.

With regard to procurement, the OPA currently has under contract about 1400 MW of renewable generation. It has a mandate to develop a further 2000 MW of renewable generation to be in service by 2015.

While the OPA's responsibilities in relation to the procurement of generation allow it to encourage the systematic development of resources from a cluster, the OPA does not appear to have express statutory responsibility under the *Electricity Act, 1998* to procure transmission facilities.[5]

[5] The OPA released a discussion paper on January 5, 2007 entitled "Ontario's Integrated Power System Plan – Discussion Paper 8: Procurement Options". This paper states, on page 3, paragraph 3 that the paper does not cover transmission procurement and points out that section 25.31(1) of the *Electricity Act, 1998* does not include transmission procurement.

Transmitters

Section 6.3.3 of the TSC requires that generators provide their own connection facilities and they do so independently of the transmitter. The transmitter to whose system the generator is connecting its facilities, and the Independent Electricity System Operator ("IESO"), must carry out certain studies to ensure that the connection of new generation has no adverse impact on other transmission customers or the grid, respectively. The costs of such studies are recovered from the connecting generator.

The Board

The Board's role in relation to generation connections is extensive. There are four principal instruments relevant to generation connections. These are:

- **The Transmission System Code:** The TSC governs the relationship between transmitters and their customers, and includes rules regarding cost responsibility for connections.
- **Review, approval and implementation of the IPSP:** The Board, in approving the IPSP, is approving the planning basis for clusters of renewable resources identified in the plan. The Board is also required to facilitate the implementation of all approved IPSPs when it exercises the powers or performs the duties given to it under statute.
- **Leave to construct:** The construction, expansion or reinforcement of electricity transmission lines that are greater than 2 km in length requires leave to construct from the Board.[6] When a transmitter is the proponent of such facilities, the transmitter is normally expected to demonstrate the need for the facilities. However, when leave to construct is required for a generation connection, the practice of the Board has been such that a demonstration of the need for the connection facility is not required in the same way since the generator proponent is taking the financial risk for the cost of such connection.
- **Licences:** Subject to any exemption set out in regulations made under the Ontario Energy Board Act, 1998 (the "Act") no person may own or operate a transmission system unless licensed by the Board to do so.[7] Among the illustrative list of licence conditions that the Board may impose are conditions that require transmitters to expand their transmission systems or to implement transmission requirements identified in an approved IPSP.[8] This condition has not yet been imposed on any transmission licence holder.

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[6] *Ontario Energy Board Act, 1998*, section 92 and Ontario Regulation 161/99, *Definitions and Exemptions*, section 6.2(1).
[7] *Ontario Energy Board Act, 1998*, section 57(b).
[8] *Ontario Energy Board Act, 1998*, sections 70(2)(j) and 70(2)(l).

As generators are responsible for paying for their own connections, the Board's **ratemaking** authority is not relevant under the existing policy.

In comparing Ontario to the other jurisdictions discussed above, it would appear that Ontario has most, but not all of the four common elements. Table 1 compares these for California, Texas and Ontario. The most relevant difference lies in coordination of the development of the generation facilities and the enabler transmission facilities. In California and Texas, transmitters develop the transmission facilities after an approval process involving the system operator (in California) or both the system operator and regulator (in Texas). A significant degree of generator commitment is required. In Ontario, while the OPA is in a good position to co-ordinate the development of the generation resources within a cluster, there is currently no central co-ordination of the associated enabler transmission facilities. By contrast, transmitters have a very limited role.

Table 1: Comparison of Enabler Development Policies

Element	*California*	*Texas*	*Ontario*
1. Clusters need to be identified and approved.	The California Energy Commission and the California Public Utilities Commission determine the “Energy Resource Areas”.	The regulator, Public Utilities Commission of Texas (“PUCT”) has designated five “Competitive Renewable Energy Zones”.	The OPA in the IPSP has identified renewable resource clusters and enabler lines.
2. The appropriate size and location of the enabler facilities must be planned and subject to some sort of regulatory review.	Regulations require that there must be generator “Interest” in the facility equivalent to 60% of its rated capacity. Line is subject to approval as a “Locationally Constrained Resource Interconnection Facility” (“LCRIF”) by the California Independent System Operator (“CAISO”).	Transmission Optimization Study carried out by the system operator the Electric Reliability Council of Texas (“ERCOT”) identifies size alternatives for connection. Sizes will be finalized by the PUCT in its final order.	Specific enabler facilities will be subject to a number of approvals, including a leave to construct approval by the Board.
3. An entity responsible for ensuring coordinated development of the clusters and associated transmission has to be identified.	Transmitter develops the LCRIF. CAISO has a duty to co-ordinate and avoid duplication through its regional planning process.	PUCT operates a competition to designate the Transmission System Providers who will build, own and operate the facilities.	OPA acts as coordinator of generation resource development. Connection to the transmission system is the responsibility of generators.
4. Financial mechanism for allocating risk and recovering costs have to be specified	Transmitters charge pro-rata share of capital costs to generators connecting to the LCRIF. All other costs are recovered through transmitter’s revenue requirement.	Generators must pay a deposit before the transmission facilities are developed. If they connect to transmission facilities within one year of operation of the facilities, this deposit is returned.	Generators bear the costs of the transmission connection facilities.

III OPTIONS FOR GENERATION CONNECTION COST RESPONSIBILITY POLICIES IN ONTARIO

This section considers four options for generation connection cost responsibility policies, and evaluates each in terms of the extent to which they promote the following two objectives: (1) economic efficiency; and (2) regulatory predictability and administrative efficiency.

Objectives

Economic Efficiency

Economic efficiency is one of the Board's guiding objectives under the *Ontario Energy Board Act*, *1998* (the "*Act*"). Specifically, item 2 of section 1(1) of the *Act* states that the Board is to be guided by the following objective: "to promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry".

Within the context of this Discussion Paper, the objective of economic efficiency can be understood to mean **achieving the connection of renewable generation resources to the transmission grid in a cost effective and timely manner**. The key issue is whether parties have both the correct incentives and the means to minimize costs. For example, by requiring generators to manage and pay for their connections, the current policy gives generators a strong incentive to minimize the total cost of energy delivered to the grid, in order to be competitive in their bid for a long-term contract with the OPA through its procurement processes. Their responsibility for connection also gives them a means of minimizing the connection cost.

Regulatory Predictability and Administrative Efficiency

Regulatory predictability relates to the ability of proponents to understand how and the basis upon which regulatory decisions are likely to be made. It can be influenced by the number of regulatory determinations or proceedings that are required in relation to a given project.

Administrative efficiency relates to the level of effort required from the perspective of proponents and other interested parties for effective participation in the processes.

Regulatory predictability and administrative efficiency facilitate investment, planning and decision-making by project proponents and helps them to better manage project risks.

Overview of Options

As noted in the introduction, the connection of clusters of renewable resources to the transmission grid could be difficult given their remote location, the small scale of a typical project relative to the optimal size of the connection, the limitations on transmitters in terms of their involvement in the construction of generation connections, and the potential for multiple proponents within a given cluster.

Each of the four options presented are evaluated in the context of these challenges and of how effectively the objectives of economic efficiency and of regulatory predictability and administrative efficiency are satisfied.

The options are differentiated on the basis of:

- Who is responsible for developing and constructing enabler facilities? **In other words who has lead responsibility?**

- Are the generators who connect to enabler facilities responsible for paying any share of the costs of such facilities? **In other words, who has cost responsibility?**

The four options that are considered are:

STATUS QUO: Generator lead responsibility; generator cost responsibility: The current connection processes and cost responsibility policies are maintained. Generators provide and pay for enabler facilities.

POOLING: Transmitter lead responsibility; costs pooled: Enabler facilities are provided by a licensed transmitter. The facilities are included in the transmission rate base and the costs are recovered from transmission ratepayers.

HYBRID: Transmitter lead responsibility; principally generator cost responsibility: Enabler facilities are provided by a licensed transmitter who owns and operates the facilities, and the associated costs are pooled temporarily. Generators make a pro-rata capital contribution towards the cost of the facilities as they become ready to connect. Any outstanding costs for the "unsubscribed" portions of the enabler facilities are recovered from transmission ratepayers. As other generators connect later, they make a pro-rata capital contribution to reduce the costs to be recovered from ratepayers.

SHARED: Transmitter lead responsibility; generator cost responsibility: Enabler facilities are provided by a licensed transmitter who owns and operates the facilities. All of the associated costs for the enabler facilities are recovered from generators that are ready to connect at an early stage. Generators connecting later also make a capital contribution, which is then used to provide a refund to the generators who connected earlier.

A detailed discussion of each of these options is presented below. However, it is useful first to outline the Board's regulatory instruments and processes that are relevant to the options, as well as the anticipated sequence of activities in relation to the development and construction of enabler facilities.

Regulatory Instruments and Processes

The Board has five principal regulatory instruments or processes that could be used to facilitate the timely development of enabler transmission lines. They are summarized here and discussed in greater detail in the description of the options.

1. The **Transmission System Code,** which defines cost responsibility for generation connections, could be amended to change lead responsibility and cost responsibility for the development including construction of enabler transmission facilities.
2. The approval of the **Integrated Power System Plan,** which provides a mechanism for identifying enabler facilities.
3. **Licence amendments** could be used to identify transmitters responsible for the development of the enabler facilities.
4. **Leave to construct** processes which could be used to ensure that such lines are needed and appropriately sized.
5. **Ratemaking** processes which could allow recovery by a designated transmitter of prudently incurred costs related to provision of enabler facilities.

Use of all five instruments is contemplated in the Pooling, Hybrid and Shared options.

Sequence of Activities

Each of the options contemplates a similar sequence of activities for the development, approval and construction of enabler facilities. These are:

Review and Approval of the IPSP: This allows for the identification of the clusters of renewable resources and the associated enabler facilities. By regulation, the OPA must submit an update of the IPSP for approval every three years.

Enabler Development and Resource Definition: Following approval of the IPSP, it is anticipated that the OPA will launch a Request for Expressions of Interest ("REI") for each of the clusters to gauge interest in cluster development. Development work on the enabler facilities (design, consultation, routing alternatives, Environmental Assessment and municipal permitting) would need to take place at this time.

Contract for Generation: When development work on the enabler facilities was sufficiently well-advanced, the OPA would, through a Request for Proposals ("RFP") process, award supply contracts in relation to the generation resources in the cluster.

Leave to Construct for Enabler Facilities: An application for leave to construct for the enabler facilities would then come before the Board for approval.

Construction and Operation: This stage involves completion of land acquisition (if necessary) and the construction of the enabler facilities, the associated generation facilities, and the connections from the generation facilities to the enabler facilities.

In addition to these five steps, the Pooling, Hybrid and Shared options contemplate two additional steps:

Transmitter designation: After the IPSP is approved, the Board would launch a process to designate a transmitter to proceed with the development of enabler facilities.

Cost recovery: The Pooling and Hybrid options contemplate recovery of at least some (Hybrid) or all (Pooling) of the costs incurred in developing and constructing the enabler facilities from transmission rates. A transmission rates case would provide for capitalization and recovery of costs once the facilities are put into service. In the Hybrid and Shared options, capital contributions from generators would be made after leave to construct approval was obtained but before construction of the facilities are initiated.

The Pooling, Hybrid, and Shared options listed above contemplate that transmitters would play a strong role in the design, development and construction of the enabler facilities and cannot be implemented without modifying the Board's current regulatory regime.[9] As described below, changes to the TSC and transmitter licences would be required, as would transmission rate hearings and Board rate orders.

[9] The status quo option does not require any changes to existing regulatory instruments.

Transmission System Code (TSC)

For the Hybrid option, a mechanism for requiring generators to pay their pro-rata share of the connection costs as and when they are ready to connect would also be required.

Status Quo Option

Under the Status Quo option, the generation proponent(s) would remain responsible for the design, development and construction of their connection to the grid. The generator has lead responsibility and cost responsibility. The current connection processes and connection cost policies are maintained.

Under these policies, how would the connection of a cluster unfold?

Status Quo Option: Outline of Process

All of the options begin with the IPSP and its identification of clusters of renewable resources. Next is the start of enabler transmission development activities which must be carried out by or on behalf of prospective generators. Also with Step 2 (see Table 2 below) the OPA may run a Request for Expressions of Interest ("REI") process. This would indicate at an early stage the level of interest in developing generation resources in the cluster and the proponents for such development. It would be this group of potential proponents, who, at the same time as proceeding with obtaining the necessary approvals for their generation facilities, would also seek, collectively or individually, to begin the approvals processes for the enabler facilities.

Step 2 reaches its conclusion only when the enabler transmission development work is substantially completed. This step is followed by Step 3 where the OPA runs its procurement Request for Proposals ("RFP") process, and then Step 4 where the generation proponents apply for leave to construct for the enabler facility. The final step in the process is construction of the enabler facility, the generation facilities and the connections between the generation facilities and the enabler facility.

Table 2: Illustrative Sequence of Activities – Status Quo

Activity	Responsibility	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Review and Approval of the IPSP (16 months)											
IPSP Submitted with clusters and enablers identified	OPA	X									
Review/approval of IPSP	OEB										
Enabler Development and Resource Definition (36+ months)											
Request for Expressions of Interest for generation	OPA/Generators										
Enabler Development (design) consultation, routing	Generators										
alternatives, EA and municipal permitting etc.											
IPSP Update											
IPSP Update submitted with more detailed information	OPA				X						
Review/approve update of IPSP	OEB										
Completion of EA/municipal approvals;	Generators						X				
Contract for Generation (3-6 months)											
Request for Proposals for cluster resources	OPA/Generators										
Award supply contracts	OPA						X				
Finalize enabler design	Generators						X				
Leave to Construct for Enablers (6 - 9 months)											
Leave to Construct application	Generators							X			
Review/approve leave to Construct	OEB										
Construction and Operation (24-36 months)											
Land acquisition and construction of enabler facilities	Generator										
Generation and connections to enabler facilities built	Generator										
Generation and enabler facilities in operation											X

Status Quo Option: Discussion

The process outlined above is expected to exhibit some serious difficulties in reaching a successful conclusion. These difficulties revolve around the coordination of transmission and generation development and the fact that, in order for the resource cluster to be exploited on a timely basis, the generation proponents would need to actively pursue transmission development work before they know whether or not they have won a generation contract in the OPA's RFP.[10]

<u>Economic Efficiency</u>

<u>Issues with Proponent Coordination</u>

The enabler transmission development phase is potentially quite lengthy and may involve complex regulatory proceedings such as a full environmental assessment. It is unrealistic to presume the completion of a generation RFP in advance of this process, as generators would, under current procurement practices, lock in a selling price for their energy but face serious future cost risks associated with both their transmission and generation assets. Holding the RFP after the completion of enabler transmission development (as assumed in the sequence laid out above) means that these *potential* proponents must actively engage in this developmental work well in advance of knowing whether or not they have an OPA contract.

These difficulties under the assumed sequence are compounded if there are many potential proponents in the cluster who must act in concert regarding the enabler development. In these circumstances it would appear that only the OPA would realistically be in a position to fund the enabler development work and seek the associated environmental approvals, municipal permits etc. before generators receive a power supply contract. This could create other difficulties. For one, the OPA while "developing" the transmission, would not ultimately procure, own or operate it. Furthermore, the question of the recovery of the costs associated with these development activities requires further consideration.

If, on the other hand, there is only one proponent who has consolidated all of the opportunities within a cluster, the coordination issues will be substantially mitigated.[11] Indeed the options analysed in this Discussion Paper may each have effects on the number and average size of proponents within a cluster (see the discussion below in each option under the heading "Ownership Consolidation Effects").

[10] Reversing the sequence – holding the procurement RFP before the transmission development work begins, seems like an answer to this problem. However, it would most likely be commercially infeasible to hold a generation procurement RFP far in advance of the in-service date of the enabler transmission.
[11] As discussed in an earlier footnote, there are examples of renewable generation that have completed their own connections to the transmission system. These cases involved single proponents and connections that were considerably shorter and less remote than the enablers identified in the IPSP.

Market Power in Connections

The potential for market power profits could motivate a generation project proponent to carry out developmental work on enabler facilities. If such a proponent is the first to develop a connection proposal the proponent might secure the most attractive right-of-way, and may be in a position to establish market power in a "connections market" that would see it supplying connection capacity to later arriving generation proponents. To exploit this market power the proponent would under-size the enabler facility. While this market power motivation could conceivably help overcome the coordination problems discussed above, it would not likely lead to the most economically efficiently sized line.

Ownership Consolidation Effects: Unintended Consequences

As noted above, each option considered here is likely to have effects on the number of proponents within a cluster and the average capacity represented per proponent. These effects are unintended consequences not because they are unpredictable (they are predictable) but because they are not objectives that the option is attempting to pursue. In other words they are side effects that may have impacts on the success or failure of the option.

In the Status Quo case, staff believe there will be a strong market force operating to consolidate ownership of the generation resources within a cluster into one or a small number of proponents. A small number of larger proponents will likely face less significant transmission / generation coordination issues and therefore the value of the entire cluster will be higher. Even for one proponent, achieving the design, development, and construction of enabler facilities could be difficult, although the odds of an efficient outcome are higher the fewer the number of proponents.

Regulatory Predictability and Administrative Efficiency

In the Status Quo, generators are responsible for providing and paying for the enabler facilities. As the responsibility and costs of the enabler facilities are not incurred by rate-regulated entities (i.e., transmitters), the Board's involvement is limited to the review and the approval of the IPSP and the review and approval of the leave to construct application for the enabler facilities[12]. As costs of the enabler facilities are borne by the generator(s), the leave to construct proceeding can be expected to be somewhat simpler than would be the case where the cost of the facilities is intended to be borne by transmission ratepayers. Thus, the Status Quo option has the fewest number of regulatory proceedings and determinations of all the options presented here.

[12] The Board would also conduct leave to construct proceedings in situations where the generator connection to the enabler was a transmission line of greater than 2 km in length.

Status Quo Summary Table

Table 3 below relates the Status Quo option to the objectives.

Table 3: The Status Quo Option Summary Table

Objective	Discussion
Economic Efficiency	Design and development work on enabler lines will be delayed as compared to the other options. With multiple proponents there will be greater difficulties in establishing the correct size of the connection, with some risk of mis-sizing it, and arriving at an inefficiently small connection, or no connection at all. Multiple proponents may start development work on more than one connection, risking multiple applications for leave to construct, none of which are designed for the cluster as a whole. Potential for one proponent to establish market power in connections. Ownership consolidation expected.
Regulatory Predictability and Administrative Efficiency	Fewer number of regulatory proceedings and determinations.

Pooling Option

In the Pooling option, transmitters would assume lead responsibility for the design, development, and construction of enabler facilities. Cost responsibility associated with enabler lines to clusters of renewable resources would lie with the transmission ratepayer, while generators would pay for their individual connections to the enabler line.

Implementation of this option would involve the following changes and additional steps beyond those applicable to the Status Quo option:

- Amendments to the Transmission System Code that expressly contemplate “enabler facilities” and assign ownership and cost responsibility for those facilities to the transmitter.
- Use of an approved Integrated Power System Plan to identify the eligible “enabler facilities”.

- A process to identify a licensed transmitter to proceed with development work on the enabler facilities identified in the approved IPSP.
- A more extensive review of the size and cost of the project at the leave to construct stage, as the costs are ultimately to be recovered from transmission ratepayers.
- A rate proceeding to allow the transmitter to recover the capitalized costs of the facilities over time.

We now examine each of these changes in more detail.

Changes to the Transmission System Code

Section 6.3.3 of the TSC requires that generators provide their own connection facilities. Enabler facilities appear to fit the TSC definition of a "connection facility" rather than the TSC definition of a "network facility" and, as such they would also appear to be the responsibility of generators. [13]

The Transmission System Code would need to be amended to create a new class of transmission facilities, called "enabler facilities" associated with renewable resource clusters. These enabler facilities would be owned and operated by a licensed transmitter. Board staff proposes the following definition of an "enabler facility": A *transmission facility to which two or more generation facilities in a renewable resource cluster may connect to convey energy to the IESO-controlled grid. Such renewable resource cluster and transmission facility must be identified as such in an integrated power system plan approved under Part II.2 of the Electricity Act, 1998.*

Board staff also proposes the following definition of a "renewable resource cluster": *A defined geographic area identified in an integrated power system plan approved under Part II.2 of the Electricity Act, 1998, where renewable resources suitable for electricity generation are present and where the renewable generation resources are, or are expected to be, owned or controlled by more than one proponent.*

It is important to note that these definitions are designed only for the case of multiple generation proponents within a cluster. In staff's view, if all of the opportunities within a cluster are consolidated under the ownership of one proponent then the lead and cost responsibility attributes of the Status Quo can adequately allow for the design, development, and construction of enabler facilities.

Code changes would specify that licensed transmitters would own and operate enabler facilities.

[13] In the TSC "connection facilities" are defined as "line connection facilities and transformation connection facilities that connect a transmitter's transmission system with the facilities of another person." "Network facilities" are defined as "those facilities, other than connection facilities, that form part of a transmission system that are shared by all users, comprised of network stations and the transmission lines connecting them."

Transmitter Licences/Designation Process

As noted above, section 70(2) of the *Act* identifies the following as specific conditions that may be included in licences issued by the Board:

j) requiring the licensee to expand or reinforce its transmission or distribution system in accordance with market rules in such a manner as the IESO or the Board may determine;….

(l) requiring the licensee to implement transmission requirements identified in an integrated power system plan approved under Part II.2 of the Electricity Act, 1998;

While the first of the above two conditions is in some, but not all transmitter licences, the Board has not, to date, included the second condition in any transmitter's licence. A licence amendment process would therefore be required to ensure the presence of the second condition in all transmitter licences.

A hearing process would be required to designate a specific transmitter to proceed with the development of enabler facilities. This could be a licence amendment process specific to a particular enabler facility (i.e., "the transmitter shall implement the following transmission requirements identified in an approved IPSP: [description of enabler facility]") or a proceeding to direct a transmitter to develop an identified enabler facility pursuant to a condition of licence that generally requires the transmitter to implement transmission requirements in an approved IPSP as directed by the Board[14].

That hearing would provide an opportunity for transmitters and other parties[15] to come forward if they wish and indicate an interest in designing, developing and (ultimately) constructing the enabler facility. Regardless of the number of transmitters interested, including the case that no party came forward, the Board would then have to designate which transmitter should be responsible for the enabler facility.

It should be noted that such designation would not preclude the possibility of another party, at its own expense, doing development work on the same facility, in parallel to the designated transmitter. If two proposals were so developed, the Board would address which of the proposals would be built when leave to construct applications were received.

Staff envisage the Board initiating this step soon after the approval of the IPSP but after the OPA has initiated an REI process to gauge the level of interest in a cluster and thus ascertain the likely size of the enabler facilities required. This would be followed by the Board's process to designate a transmitter to provide the enabler facilities. Once the designation had been made, the transmitter would proceed with the development work.

[14] This latter approach presupposes that the transmitter's licence has previously been amended to include a general condition that mirrors the language of section 70(l) of the *Act.*
[15] Any such other party would need to be licensed as a transmitter if it were to own or operate an enabler facility.

When this is substantially complete, the OPA would conduct its RFP procurement process to firm up the generation capacity being developed in the cluster. This would then allow the transmitter to finalize the size of the enabler facilities and bring forward an application for leave to construct.

Leave to Construct

At the leave to construct stage, the Board would need to closely scrutinize the need for, the appropriate size of, and the expected costs of the enabler facilities. This is necessary as these costs are to be ultimately recovered from transmission ratepayers.

Financial / Rates Considerations

After leave to construct approval is obtained, the transmitter would normally include the facility in its next rates application with the Board[16]. The ensuing rates proceeding will determine a revenue requirement that would be added to the aggregate revenue requirement across all transmitters that figure in the Board's uniform transmission rates mechanism. There is no incremental load associated with these new revenues so the uniform rate for the Network Pool will have to increase in order to provide this increment in revenue. The transmitter would receive these revenues through the normal settlement processes carried out by the IESO.

If, for some reason, a particular enabler facility project was abandoned, the designated transmitter could apply to recover the prudently incurred costs associated with development of these facilities.

[16] This process could apply to an incumbent transmitter such as Hydro One Networks Inc. In the case where a "merchant transmitter", an entity having no actual transmission assets in the province, is responsible for the enabler facilities, it would need to make an application to the Board. . In either case, transmitters would start earning a return on these assets, once the facilities are constructed and put into service.

Table 4: Illustrative Sequence of Activities: Pooling

Activity	Responsibility	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Review and Approval of the IPSP (16 months)											
IPSP Submitted with clusters and enablers identified	OPA	X									
Review/approval of IPSP	OEB										
Transmitter Designation (6 months)											
Board Order assigning transmitter to develop enabler	OEB			X							
Enabler Development and Resource Definition (36+ months)											
Request for Expressions of Interest for generation	OPA/Generators										
Enabler Development (design) consultation, routing	Transmitter										
alternatives, EA and municipal permitting etc.											
IPSP Update											
IPSP Update submitted with more detailed information	OPA				X						
Review/approve update of IPSP	OEB										
Completion of EA/municipal approvals;	Transmitter						X				
Contract for Generation (3-6 months)											
Request for Proposals for cluster resources	OPA/Generators										
Award supply contracts	OPA						X				
Finalize enabler design	Transmitter						X				
Leave to Construct for Enablers (6 - 9 months)											
Leave to Construct application	Transmitter							X			
Review/approve leave to Construct	OEB										
Construction and Operation (24-36 months)											
Completion of land acquisition (if necessary) and construction of enabler facilities	Transmitter										
Generation and connections to enabler facilities built	Generator										
Generation and enabler facilities in operation											X
Cost Recovery											
Transmission Rates Case application	Transmitter								X		
Transmission Rates Case review and approval	OEB										

Pooling Option: Discussion

Economic Efficiency

Proponent Coordination

Relative to the Status Quo option, the Pooling option solves the problems associated with potential generation proponents attempting to coordinate the development of an enabler facility. The risk of a delayed or undersized line is therefore mitigated under the Pooling option.

Averch-Johnson Effect

Under conventional rate regulation, a utility's most direct route to higher net income is via the expansion of the rate base. The Pooling option provides regulated transmitters with the opportunity to expand their rate base, in contrast with the Status Quo where these "enabler" assets would not be constructed or owned by regulated transmitters. This provides transmitters with an incentive to develop the enabler facilities. However, the concern, based on concepts first expressed by Averch and Johnson[17], is that regulatory oversight, while needed, may prove less effective at ensuring that the appropriately-sized facilities are constructed than if generators were to develop and pay for these assets. In other words, enabler facilities are more likely to be oversized than under the Status Quo option.

Ownership Consolidation Effects: Unintended Consequences

The Pooling option may adversely affect proponents' motivation to consolidate ownership of resources within a cluster. A single large proponent representing an entire cluster might see an incentive to dis-integrate into multiple proponents in order to be eligible for the Pooling option. Pooling gives the proponent the option of eliminating the transmission cost risk it faces if it dis-integrates into multiple smaller proponents.[18]

If the starting point in the cluster was multiple proponents, there would be no incentive to change this under the Pooling option as generators are free of any responsibility for transmission – the enabler facility will be provided at no cost to them no matter how many proponents there are.

[17] The Averch-Johnson Effect is the tendency identified in economic theory for regulated utilities to over-accumulate capital as a means of raising the volume of profit. See Averch, Harvey, Leland L. Johnson *Behaviour of the Firm Under Regulatory Constraint*, American Economic Review, December 1962, vol 52, issue 5, page 1952.

[18] A single proponent responsible for its own transmission bears considerable transmission cost risk. If the proponent fails to complete the transmission, or completes it late and at higher than expected costs, it will earn a lower return on capital than expected, or none at all.

Regulatory Predictability and Administrative Efficiency

The Pooling option requires additional regulatory proceedings and determinations than is the case in the Status Quo option, including: the designation of a transmitter to provide the enabler facility, a more extensive review at the leave to construct stage, and a rates proceeding to determine the transmitter's cost recovery. Regulatory predictability may therefore be less than under the Status Quo option.

The larger number and complexity of the regulatory proceedings adds an administrative burden for the transmitter. By contrast,   generators no longer have to be concerned about the enabler facilities or with coordinating with each other and thus would experience less of an administrative burden than under Status Quo option.

Table 5 below relates the Pooling option to the objectives.

Table 5: The Pooling Option Summary Table

Objective	Discussion
Economic Efficiency	This option mitigates the risks of undersized and / or delayed enabler lines that are present in the Status Quo option. Greater risk of oversized lines. Pooling will provide incentive for single proponent to dis-aggregate. If starting point is multiple proponents, no incentive to consolidate.
Regulatory Predictability and Administrative Efficiency	Greater number of regulatory determinations relative to the Status Quo option may reduce regulatory predictability. Transmitter faces more significant administrative burden with additional proceedings relative to the Status Quo option. The administrative burden on generators is reduced relative to the Status Quo option.

Hybrid Option

The Hybrid option is identical to the Pooling option except that cost responsibility for the enabler facilities rests primarily with the generators. In addition to the changes to the TSC outlined for the Pooling option, the TSC would also need to be amended to specify how and when generators would pay for the cost of the enabler facilities. This could be accomplished by requiring:

- Generators wishing to connect to the facility would make a capital contribution once the transmitter has obtained leave to construct for the enabler facilities.
- The amount of the contribution would be calculated as a share of the cost of the facility pro-rated to its capacity. For example, if the capacity of the generator's facility is 100 MW, and the capacity of the line is 500 MW, the generator would be responsible for 20 percent of the total project cost.

A key question in the Hybrid option is what to do about unutilized enabler capacity. For example, what if only 400 MW of generation capacity within the cluster is being developed at the time enabler facilities with a capacity of 500 MW are to be constructed? Under this option, the cost of the uncommitted capacity would be included in the transmission rate base. Thus if one generator of 100 MW were connecting, it would pay 20 percent of the project cost. As new generation facilities in the cluster become ready to connect, the connecting generator pays its pro-rata share of the depreciated connection costs. These later capital contributions reduce the transmission asset rate base and hence transmission rates. Over time, as the potential of a renewable resource cluster is increasingly exploited, cost responsibility shifts from the pooled cost base back to the generator(s).

Hybrid Option: Outline of Process

The steps in the Hybrid option (Table 6) closely mirror those in the Pooling option, with the exception of a requirement that generators make a capital contribution to the transmitter once the leave to construct has been granted.

Table 6: Illustrative Sequence of Activities: Hybrid

Activity	Responsibility	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Review and Approval of the IPSP (16 months)											
IPSP Submitted with clusters and enablers identified	OPA	X									
Review/approval of IPSP	OEB										
Transmitter Designation (6 months)											
Board Order assigning transmitter to develop enabler	OEB			X							
Enabler Development and Resource Definition (36+ months)											
Request for Expressions of Interest for generation	OPA/Generators										
Enabler Development (design) consultation, routing	Transmitter										
alternatives, EA and municipal permitting etc.											
IPSP Update											
IPSP Update submitted with more detailed information	OPA				X						
Review/approve update of IPSP	OEB										
Completion of EA/municipal approvals;	Transmitter						X				
Contract for Generation (3-6 months)											
Request for Proposals for cluster resources	OPA/Generators										
Award supply contracts	OPA						X				
Finalize enabler design	Transmitter						X				
Leave to Construct for Enablers (6 - 9 months)											
Leave to Construct application	Transmitter							X			
Review/approve leave to Construct	OEB										
Construction and Operation (24-36 months)											
Completion of land acquisition (if necessary) and construction of enabler facilities	Transmitter										
Generation and connections to enabler facilities built	Generator										
Generation and enabler facilities in operation											X
Cost Recovery											
Generator Capital Contributions	Generator								X		
Transmission Rates Case application	Transmitter								X		
Transmission Rates Case review and approval	OEB										

Hybrid Option: Discussion

Economic Efficiency

Problems with Proponent Coordination

Relative to the Status Quo option, the Hybrid option solves the problems associated with potential generation proponents attempting to coordinate the development of an enabler facility. The risk of a delayed or undersized line is therefore mitigated under the Hybrid option.

Averch-Johnson Effect

The Hybrid option would mitigate the Averch-Johnson effect relative to the Pooling option, as the transmitter who develops and constructs the enabler facility will not expect that facility to remain permanently in its rate base. Thus, the advantage from the regulated entity's perspective of a larger facility is greatly diminished but conversely it has less incentive to develop such facilities. On the other hand, under the Hybrid option generators would tend to favour a larger facility offering greater economies of scale and lower unit costs. This is because they are responsible only for their own pro-rata share of costs and are not cost responsible for un-utilized facilities.

Ownership Consolidation Effects: Unintended Consequences

If there is only a single proponent within the renewable resource cluster, there is little incentive for that proponent to disaggregate into two or more proponents as it will still be responsible for cost of the enabler facilities.

If the starting point in the cluster is multiple proponents, there will be a greater incentive to consolidate into a smaller number than would be the case in the Pooling option. As larger entities they may have easier access to the capital markets in order to raise funds for capital contributions. Also, as larger proponents they will find coordinating their regulatory interventions easier, and are less likely to duplicate efforts.

Regulatory Predictability and Administrative Efficiency

The Hybrid option requires additional regulatory proceedings and determinations than is the case in the Status Quo option, including: the designation of a transmitter to provide the enabler facility, a more extensive review at the leave to construct stage, and a rates proceeding to determine the transmitter's cost recovery. Regulatory predictability may therefore be less than under the Status Quo option.

Relative to the Pooling option, the Hybrid option will need to specify the size of capital contributions to be made by generators. The methodology calculating the amount of this contribution could be included in the TSC, increasing regulatory predictability.

As with the Pooling option, the larger number and complexity of regulatory proceedings adds an administrative burden for the transmitter. By contrast, generators no longer have to be concerned about developing the enabler facilities or with coordinating with each other and thus would experience less administration than under status quo.

Table 7: The Hybrid Option Summary Table

Objective	Discussion
Economic Efficiency	This option mitigates the risks of undersized and / or delayed enabler lines that are present in the Status Quo option. Reduced tendency to oversize lines relative to the Pooling option, due to ultimate generator cost responsibility, and generator participation in proceedings. Hybrid option will provide little incentive for single proponent to dis-aggregate. If starting point is multiple proponents, some incentive to consolidate relative to Pooling option.
Regulatory Predictability and Administrative Efficiency	Greater number of regulatory determinations relative to the Status Quo option may decrease regulatory predictability. Transmitter faces more significant administrative burden with additional proceedings relative to the Status Quo option. The administrative burden on generators is reduced relative to the Status Quo option. . Methodology of calculating capital contributions from generators can be included in TSC, increasing regulatory predictability.

Shared Option

The Shared option is identical to the Hybrid option except that cost responsibility for the enabler facilities rests entirely, rather than just primarily, with the generators. This would avoid reliance on the transmission customers for cost recovery if the enabler facilities are constructed and put into service[19]. As is the case for the Hybrid option, the TSC would need to be amended to specify how and when generators would pay for the cost of the enabler facilities. Under the Shared option, however, the cost responsibility is somewhat different:

- Generators wishing to connect to the facility would make a capital contribution once the transmitter has obtained leave to construct for the enabler facilities.
- This capital contribution would be estimated on the basis that each generator is made responsible for a share of the cost of the facility pro-rated to its capacity and in proportion to the total capacity initially connecting to the enabler facilities. For example, a generator with 100 MW capacity out of 400 MW of total generation would be responsible for 25 percent of the total cost of the enabler facilities, even if the capacity of the facilities were 500 MW.
- If another generator subsequently connected to the enabler facilities, it would also be obliged to make a capital contribution which would be paid as a refund to the other generators that connected earlier[20].

Shared Option: Outline of Process

The steps in the Shared option (Table 8) closely mirror those in the Hybrid option, with the exception that a rates case to include the cost of the unallocated enabler capacity in the transmission rate base would not be needed.

[19] If however, the project were terminated at the development stage, the designated transmitter could be allowed to recover prudently incurred costs from transmission ratepayers.
[20] The TSC currently provides for refunds for unutilized capacity on **load** connection facilities should other customers subsequently connect (up to five years).

Table 8: Illustrative Sequence of Activities: Shared

Activity	Responsibility	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Review and Approval of the IPSP (16 months)											
IPSP Submitted with clusters and enablers identified	OPA	X									
Review/approval of IPSP	OEB										
Transmitter Designation (6 months)											
Board Order assigning transmitter to develop enabler	OEB			X							
Enabler Development and Resource Definition (36+ months)											
Request for Expressions of Interest for generation	OPA/Generators										
Enabler Development (design) consultation, routing	Transmitter										
alternatives, EA and municipal permitting etc.											
IPSP Update											
IPSP Update submitted with more detailed information	OPA				X						
Review/approve update of IPSP	OEB										
Completion of EA/municipal approvals;	Transmitter						X				
Contract for Generation (3-6 months)											
Request for Proposals for cluster resources	OPA/Generators										
Award supply contracts	OPA						X				
Finalize enabler design	Transmitter						X				
Leave to Construct for Enablers (6 - 9 months)											
Leave to Construct application	Transmitter							X			
Review/approve leave to Construct	OEB										
Construction and Operation (24-36 months)											
Completion of land acquisition (if necessary) and construction of enabler facilities	Transmitter										
Generation and connections to enabler facilities built	Generator										
Generation and enabler facilities in operation											X
Cost Recovery											
Generator Capital Contributions	Generator								X		

Shared Option: Discussion

Economic Efficiency

Issues with Proponent Coordination

As with the Pooling and Hybrid options, the Shared option solves the issues associated with potential generation proponents attempting to coordinate the development of an enabler facility. The risk of a delayed line is therefore mitigated by the Shared option.

Averch-Johnson Effect

The Shared option would mitigate the Averch-Johnson effect relative to the Pooling option, as the transmitter who develops and constructs the enabler facility will not expect that facility to be in its rate base. Thus, the advantage from the regulated entity's perspective of a larger facility is greatly diminished and conversely, it has little incentive to develop such facilities. Also, under the Shared option generators are more likely to take an interest in the lowest cost, but not necessarily lowest unit cost, and smallest capacity of the enabler facility because they will ultimately bear cost responsibility for it. As such, they can be expected to intervene in the relevant regulatory proceedings before the Board.

However, generators would not know what share of the cost of the enabler facilities they would need to bear when they bid for a supply contract with the OPA. This places an additional risk on the generators which would need to be mitigated, possibly through the contracting mechanism.

Ownership Consolidation Effects: Unintended Consequences

If there is only a single proponent within the renewable resource cluster, there is no incentive for that proponent to disaggregate into two or more proponents as it will still be entirely responsible for cost of the enabler facilities.

If the starting point in the cluster is multiple proponents, there will be greater incentive to consolidate into a smaller number than would be the case in the Pooling option. As larger entities they may have easier access to the capital markets in order to raise funds for capital contributions. Also, as larger proponents they will find coordinating their regulatory interventions easier, and are less likely to duplicate efforts. However, this incentive will not likely drive them into a full consolidation as one large proponent.

Regulatory Predictability and Administrative Efficiency

The Shared option would be simpler than the Hybrid option. There would be no need for inclusion of the enabler facilities in the transmission rate base and hence no need for a transmission rates case[21], although there would be administration of refunds from later capital contributions. The leave to construct review would also be simpler as the costs of the facilities would not be included in transmission rate base. The methodology for calculating the amount of capital contributions, and for specifying how refunds are to be made, could be included in the TSC, increasing regulatory predictability.

As for administrative efficiency, the Shared option seems similar to the Hybrid Option, although by excluding the facilities from rate base, a rates proceeding may not be needed.

Table 9: The Shared Option Summary Table

Criterion	Discussion
Economic Efficiency	This option mitigates the risks of undersized and / or delayed enabler lines that are present in the Status Quo option. Generator cost responsibility reduces incentive to oversize lines. Generators have higher risks with respect to cost responsibility for the enabler lines, unless this risk is mitigated in some way through the contracting mechanism. Shared option will not provide incentive for single proponent to dis-aggregate. If starting point is multiple proponents, some incentive to consolidate relative to Pooling option.
Regulatory Predictability and Administrative Efficiency	Greater number of regulatory determinations relative to the Status Quo option may reduce regulatory predictability. Transmitter faces more significant administrative burden with additional proceedings relative to the Status Quo option. Unlike the Hybrid and Pooling options, no rate issues. Generators administrative burden is reduced relative to Status Quo. Methodology of calculating capital contributions from generators can be included in TSC, increasing regulatory predictability.

[21] Assuming the facilities and associated generation were constructed.

IV Questions to Guide Stakeholder Input

The following questions are intended to assist stakeholders in providing written comments on this Discussion Paper and the options presented therein.

1. Is it appropriate to change the current policies for the provision of generation connections as it applies to enabler lines?
2. If so, do you agree with the definition of enabler lines as proposed and, in particular, that: (a) enabler facilities are those that serve multiple generation facilities with different owners; and (b) the revised policies apply only to those enabler facilities that are part of an approved IPSP?
3. Do you agree with the proposed process in the Pooling, Hybrid and Shared options that once the IPSP is approved, the Board should undertake a process to designate a transmitter as responsible for the development phase of the enabler facilities? If not, what process should the Board use to ensure that development work on the enabler facilities proceeds?
4. Is the timing for the Request for Expressions of Interest and Request for Proposals relative to the stage of the development work on the enabler facilities appropriate?
5. Should the costs of the enabler line be recovered from transmission ratepayers or from generators?
6. Should the costs associated with the unsubscribed portion of the enabler facility's capacity be recovered from transmission ratepayers (as in the Pooling and Hybrid options) or should they be paid by generators (as in the Status Quo and Shared options)?

APPENDIX I: TRANSMISSON POOLS

The transmission facilities owned by licensed transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the **Network Pool**. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the **Transformation Connection Pool**. Other electric facilities (i.e., that are neither Network nor Transformation) are categorized as the **Line Connection Pool**.

Section 2 of the Transmission System Code defines Network, Line Connection and Transformation Connection as follows:

> **Network** facilities mean those facilities, other than connection facilities, that form part of a transmission system that are shared by all users, comprised of network stations and the transmission lines connecting them.
>
> **Line Connection** means radial lines that do not, under normal operating conditions, connect network stations and whose sole purpose is to serve one or more persons.
>
> **Transformation Connection** means transformation facilities, tapped off a transmission system. That step down voltages from transmission levels to distribution levels (i.e. from more than 50 kV to 50 kV or less) in order to supply the facilities of a person.

The functional classification of transmission assets affects the determination of the revenue requirement of the three transmission rate pools of the Provincial Transmission Rate Schedule as well as a number of other aspects of how transmission assets are to be treated.

The following table outlines the rate treatment of the pools as well as the other aspects of the pools.

It is interesting to note that the contestability and ownership features are, under the Status Quo, essentially non applicable to generation connections. This reflects the fact that the Status Quo does not contemplate significant transmitter involvement in generator connections. These features may need to change in the enabler line context.

Table A1: Transmission Pool Aspects

	Connection Assets [Line and Transformation]	***Network Assets***
Rate Treatment	All customers that utilize a transmitter's transmission lines to connect to Network stations pay rates for the Line Connection pool of assets. All customers that utilize a transmitter's transformation facilities that step down from above 50 kV to below 50kV pay rates for the Transformation Connection pool of assets.	All customers of licensed transmitters pay rates for the Network pool of assets.
Rate Determinant ***[Ref: Provincial Transmission Rate Schedule]***	The customer's monthly non-coincident peak demand plus the demand supplied by embedded generation > 1MW p.u. (> 2MW p.u. for renewable)	The higher of: a) the customer's monthly coincident peak demand or b) 85% of the customer's monthly non-coincident peak demand.
Cost Responsibility ***[Ref. sec. 6.3 of the TSC]***	Costs for new or modified Connection assets are allocated to specific customer(s) that benefit. Cost responsibility is also enforced through by-pass [ref. 11.2] and true-up [ref. 6.5.6] clauses.	Costs for new or modified Network assets are not allocated to specific customers except if "exceptional circumstances exist" [ref. 6.3.5]
Contestability ***[Ref. sec. 6.6 of the TSC]***	Load customers: new connection facilities may be constructed by the customer. Generators: N/A	N/A N/A
Ownership	Load customers: new dedicated facilities may be owned by the transmitter or the customer. Generator: new dedicated facilities must be owned by the generator [ref. 6.3.3]	N/A N/A

APPENDIX II: A Survey of Other Jurisdictions

Transmission Connection Cost Recovery Policies for Renewable Generation: A Survey of Other Jurisdictions

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July 7, 2008

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Table of Contents

1. Introduction

Power Advisory LLC (Power Advisory) was engaged by the Ontario Energy Board (OEB) staff to assist with its review of the connection cost responsibilities policies employed in other jurisdictions to promote the development of cost-effective renewable generation. In particular, Power Advisory was requested to review the policies employed in Texas, California and the United Kingdom (UK). Stakeholder submissions and comments identified Texas and California as jurisdictions that were pursuing innovative policies for the development of enabler transmission lines that offered considerable promise for promoting the development of cost-effective renewable resources.

This report reviews the market structure and institutions for each jurisdiction to provide context given their importance in influencing the form of the framework adopted. This institutional context also is critical to assessing the degree to which these frameworks, or elements of them, could be applied to Ontario.

2. Texas: Competitive Renewable Energy Zones

2.1 Introduction

Texas is developing Competitive Renewable Energy Zones (CREZs) which are areas with significant renewable resource potential, but require considerable transmission investment. The Public Utility Commission of Texas (PUCT) is responsible for establishing the zones. Generators are required to demonstrate interest, but do not have cost responsibility for the proposed transmission facilities. Transmission companies compete for the right to develop and construct the required transmission facilities.

The objectives of establishing CREZs are to:

- ensure that sufficient transmission infrastructure is built to meet the State's goal for renewable energy;
- improve the coordination between the construction of transmission facilities and renewable generation facilities; and
- avoid duplication in determining the need for new transmission facilities (e.g., between the CREZ case and any subsequent Certificate of Convenience and Necessity (CCN) proceeding).

The CREZ rule expedites the process by which new transmission projects serving renewable energy resources may be approved by the PUCT and reduces the risk that a utility's construction of transmission to serve a potential wind zone might be challenged as not providing benefit to the utility's customers. The identification of CREZs will also reduce the development risks for renewable generation.

The PUCT outlined the rationale for CREZs as follows:

> "The rapid development of wind power in West Texas since 2001 has shown that wind farms can be built more quickly than transmission... This timing difference

poses a dilemma for planning: it is difficult to know whether a new transmission line will be needed if the generation facilities do not yet exist, but a wind farm is difficult to finance if there is no certainty that sufficient transmission will be available. Senate Bill 20 is an effort to solve this dilemma by authorizing the Commission to identify areas with sufficient renewable energy potential, identify the transmission facilities that could serve the area, and establish the need for new transmission facilities serving the area, even if no specific renewable generation projects exist or are under construction."[22]

2.2 Institutional Context

The majority of Texas (about 85%) participates in a market that is overseen by the Electricity Reliability Council of Texas (ERCOT). Unlike most other competitive markets, ERCOT has no publicly administered power exchange for day-ahead power transactions or longer-term market for capacity. ERCOT does oversee various ancillary markets that support its largely bilateral market structure.[23] The markets that are administered by ERCOT represent a relatively small proportion of the total costs of the electricity commodity.

The ERCOT market is one of the most competitive wholesale power markets in North America. New generation development has provided about 37,000 MW of capacity, representing about half of the existing capacity.

The PUCT plays an important role with respect to the oversight of the ERCOT market including serving as the market monitor. The PUCT also reviews proposals for the construction of new transmission facilities. ERCOT is located entirely within Texas so it is exempt from FERC oversight or regulation.

Texas has a renewable portfolio standard (RPS) of 5,880 MW of renewable capacity by 2015 and a target of 10,000 MW by 2025. Given a favourable wind resource and a market where natural gas-fired generation is the marginal resource for the vast majority of time, there has been considerable wind project development. As of December 31, 2007, Texas had 4,356 MW of wind capacity, with over 1,600 MW entering commercial operation in 2007.[24] This wind generation represents about 97% of the renewable generation that qualifies for the state RPS.

Transmission costs are paid by load, except for interconnection costs which are directly assigned to generation. CREZs costs will be rolled into transmission rates and paid by load. Transmission is priced using a postage stamp rate, with rates uniform regardless of location.

Any solution for promoting the development of major new transmission facilities to enable the development of the state's wind generation potential needed to recognize this strong market

[22] PUCT, Need for Transmission and Generation Capacity in Texas: Renewable Energy Implementation and Costs, December 2006, p. 14.
[23] ERCOT also administers transmission access and coordinates transmission planning.
[24] American Wind Energy Association, 2007 Market Report, January 2008, p. 7.

orientation and relatively high level of confidence in market solutions. Given this strong market orientation there is no central planning.

2.3 The CREZ Framework

CREZs were proposed by the Texas State Legislature (Senate Bill 20) to better realize the state's considerable wind generation potential. Under this legislation, the PUCT was required to designate CREZs throughout the state and develop a plan to construct the transmission necessary to deliver the output from renewable energy technologies in the zones. The PUCT directed ERCOT, in its role as coordinator of transmission planning and analysis for the ERCOT region, to complete a study of possible transmission improvements and to provide estimates of the transmission capital costs and forecasted system benefits associated with the designation of different areas in the State as CREZs. ERCOT (through a consultant with expertise in this area) first identified the areas of the State that contained the best wind resources. The areas, their wind generation potential, and the associated transmission costs were identified in a report filed with the PUCT.[25] ERCOT then identified specific transmission upgrades that would allow varying levels of new wind generation to be installed in these areas of significant wind potential.

The criteria used by the PUCT to establish the CREZs as outlined by the enabling legislation are: (1) sufficiency of renewable energy resources and land areas to develop generating capacity from renewable energy technologies; (2) the level of financial commitment by generators for each potential CREZ; and (3) to assess the level of financial commitment the PUCT indicated that it would consider "existing development, signed and pending interconnection agreements (IAs) for units not yet in service, fees paid by generators for interconnection studies, executed leasing agreements with landowners, voluntary letters of credit assuring the developer's intent to build in the CREZ."[26,27]

Using these criteria, in an interim order (Docket No. 33672) the PUCT designated five zones that were identified in the ERCOT Report as CREZs. The transmission to enable the wind generation potential in these five zones would have a transfer capability of from 5,150 MW to 17,516 MW, depending on the scenario. In the final order the PUCT will identify the "transmission improvements necessary to deliver to customers energy generated by renewable resources in the CREZ."[28] To make this determination, the PUCT requested ERCOT to perform a "CREZ Transmission Optimization Study". This study was filed with the PUCT in early April.

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[25] ERCOT, "Analysis of Transmission Alternatives for Competitive Renewable Energy Zones in Texas", December 1, 2006.
[26] PUCT, "Rulemaking Relating to Renewable Energy Amendments" (CREZ Rulemaking), December 1, 2006, p. 4.
[27] Developers are required to take service under the CREZ transmission facilities within one year of notification by the TSP that the facilities can accommodate the output of the facilities. Developers risk forfeiting any collateral if they fail take service within 12-months of such a notification, unless they receive an extension from the PUCT.
[28] Interim Order, Docket No. 33672.

An indication of the magnitude of the required capital investment is provided by the CREZ Transmission Optimization Study. This study identified five alternatives which ranged from $2.95 billion to $6.38 billion and would interconnect from 12,053 to 24,859 MW.[29]

The PUCT has also instituted a rulemaking to set the criteria for establishing the transmission service providers (TSPs) that can build the transmission projects identified in the CREZ Final Order. As such, a fundamental element of this process is to promote competition in the construction of these projects. The framework outlined by the PUCT requires a TSP to first demonstrate that it has the ability to construct, operate and maintain the facilities. Qualified TSPs then file proposals to construct and operate the CREZ transmission facility.

The PUCT has established the following schedule for selecting the TSP:

(1) Receive transmission study from ERCOT and select transmission projects: *First – Third Quarter 2008*;
(2) Qualification of TSPs: *Second – Fourth Quarter of 2008*;
(3) Designate TSPs for various CREZ transmission projects: *Third Quarter 2008 – Second Quarter 2009*;
(4) Designated TSPs file a Certificate of Convenience and Necessity (CCN) for the transmission project: *Second Quarter 2009;*
(5) Construction commences with approval of CCN applications by the PUCT.

Based on this schedule the selection of TSPs takes 12 to 15 months.

After the Transmission utility files the CCN, generation developers in the CREZ must post a letter of credit or other collateral equal to 10% of their share of CREZ costs.[30] If this requirement isn't satisfied then the PUCT can reconsider the CREZ designation.

The CREZ Final Order will indicate the "construction of transmission capacity necessary to deliver to electric customers, in a manner that is most beneficial and cost-effective to the customers, the electric output from renewable energy technologies."[31] The CREZ Final Order also will identify a set of transmission improvements. "Each new or upgraded line will be identified by voltage level, and by where the line will connect to the existing grid. Some of the transmission improvements may not be in close proximity to the intended development, and may serve purposes in addition to facilitating renewable energy development in the zone. The order will also include an estimate of the maximum generation capacity that the CREZ can accommodate once the improvements identified in the order are in service."[32]

[29] ERCOT, CREZ Transmission Optimization Study, April 2, 2008.
[30] This financial security is ultimately returned to the generation developers if they build their project and connect to the network.
[31] CREZ Rulemaking, p. 5.
[32] CREZ Rulemaking, p. 5.

The TSP may propose modifications to the parameters included in the CREZ order if its study reveals alternatives that would reduce costs or increase the amount of generating capacity that transmission improvements for the CREZ can accommodate.

3. California: Renewable Energy Transmission Initiative

3.1 Introduction

California has adopted an aggressive renewable portfolio standard which requires that 20% of its electricity be provided by renewable electricity resources by 2010. Achieving this goal will require extensive enhancements to its electric transmission infrastructure. The Renewable Energy Transmission Initiative (RETI) is a "statewide planning process that will identify the transmission projects needed to accommodate these renewable energy goals."[33] RETI will assess all competitive renewable energy zones (CREZs) in California and neighboring states that can provide significant amounts of renewable electricity and then evaluate the economics and environmental impacts of these CREZs to determine which can be developed most cost-effectively and in the most environmentally benign manner. Finally, detailed transmission plans will be prepared for the CREZs identified for development.

RETI is overseen by a Coordinating Committee comprised of the California entities responsible for ensuring the implementation of the state's renewable energy policies and the development of its transmission infrastructure: California Public Utilities Commission (CPUC); California Energy Commission (CEC); California Independent System Operator (CAISO); Southern California Public Power Authority (SCPPA); Northern California Power Agency (NCPA); and Sacramento Municipal Utility District (SMUD).[34]

3.2 Institutional Context

California's electricity industry is complex, with traditional utilities, private generating companies and state agencies each playing a variety of roles and having different responsibilities.

Three investor-owned utilities (IOUs) - Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E) - serve over two thirds of the California electricity demand. Municipal utilities, power authorities and cooperatives serve the remaining one-third of demand.

The major transmission lines are owned by these IOUs who develop their own expansion plans. The CAISO evaluates the need and the CPUC then assesses the degree to which the proposals best serve the public convenience and necessity. The CAISO also operates the state's wholesale power grid and administers the real-time power markets.

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[33] Renewable Energy Transmission Initiative Mission Statement, December 21, 2007, p. 1.

[34] As restructured power market, the California investor-owned utilities transmission facilities are under the control and operation of the CAISO.

California has a competitive wholesale power market that provides a real-time price signal. However, investor confidence in the market was undermined by the imposition of price caps. As such, much of the generation is developed on the basis of long-term power purchase agreements with the state's investor and municipally-owned public utilities.

With respect to regulation, policy and planning, the main entities are the CPUC, the CEC, and the Federal Energy Regulatory Commission (FERC). The CPUC regulates investor-owned electric utilities within the state, ensuring that utilities plan for and make investments in energy resources necessary to ensure that California consumers receive reliable service at "low and stable" prices. In 2004 the CPUC adopted a procurement policy framework under which the IOUs plan and invest in energy resources.[35]

As part of this framework, the CPUC has adopted a resource adequacy requirement to ensure that there is adequate, cost-effective investment in electric generation capacity; and that such capacity is made available to the CAISO when and where it is needed for reliable transmission grid operations.

The CEC is the state's primary energy policy and planning agency, with responsibilities to forecast future energy needs, license large thermal power plants, promote energy efficiency, develop energy technologies and support renewable energy.

The FERC regulates interstate transmission of electricity and regulates transmission pricing under its *pro forma* open-access transmission tariff to remedy undue discrimination and increase transparency in the rules applicable to planning and use of the transmission system. FERC also regulates generator interconnections and has issued standard procedures and interconnection agreements for generators.

Established in 2002 under Senate Bill 1078 and accelerated in 2006 under Senate Bill 107, California's Renewables Portfolio Standard (RPS) is one of the most ambitious renewable energy standards in the country. The RPS requires 20% of the state's electricity to be generated by renewable resources by 2010, with a longer-term goal of 33% by 2020.

A major issue arising from the adoption of an aggressive RPS program is the lack of transmission to access location-constrained resources. The CAISO asserted in its petition to FERC[36] that its current policy - requiring generation developers to pay the cost of generation tie lines - has impeded the financing and construction of lines to access location-constrained resources. FERC established its interconnection policy prior to recent initiatives to develop renewable resources on a much larger scale.[37]

The proliferation of interconnection requests for renewable generation has imposed significant challenges to the efficiency of the CAISO's "first-in, first-out" interconnection study approach. For example, the CAISO currently has 188 active interconnection requests totaling 62,608 MW for a system with a historic peak of 50,270 MW; 42,526 MW are associated with renewable

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[35] The IOUs are allowed to own new generation.
[36] FERC, Docket No.EL07-33-000, Order Granting Petition for Declaratory Order.
37 FERC, Order Granting Petition for Declaratory Order, 119 FERC ¶ 61,061

resources. The large number of requests has overwhelmed available resources, led to delays and frustration with the study process, and exposed fundamental deficiencies in the current study approach.

The CAISO is working to address these issues in the Generator Process Interconnection Reform (GPIR) Initiative. RETI would help rationalizing this process. GPIR is a holistic approach: "First, the GIPR abandons a project-by-project study approach in favor of studies that group together electrically related proposed generation projects. Second, development and planning of the actual network transmission upgrades necessary to accommodate the interconnection requests are transferred to the CAISO's Transmission Planning Process."[38]

The Tehachapi area in Southern California has been cited as an example of a situation where insufficient interconnection capacity may be preventing the development of location-constrained resources. The Tehachapi range boasts California's largest concentration of wind turbines, currently producing 600 megawatts, with up to 1,100 megawatts of new wind projects planned.

As noted in FERC's Order, the amount of wind generation in the CAISO's interconnection queue for the Tehachapi area has increased more than fourfold since the CPUC ordered SCE to expand transmission in the area and the first report on transmission options was issued. Prior to the CPUC's action, market participants were able to privately finance the construction of one interconnection facility from Tehachapi to the CAISO-controlled grid. The FERC issued a series of orders relating to this line to address competing requests for capacity. These competing requests indicate that the interconnection facility is undersized and insufficient capacity exists to meet all requests for service. The inefficient way in which the Tehachapi area has been developed highlights the need to address the incremental nature of renewable resource development.

3.3 California RETI Mechanism

RETI began as a collaborative between the CPUC and the CEC, then evolved to include the CAISO, municipal utilities, and a broad range of stakeholders, to design a statewide planning process. RETI will identify RPS resources in the state and along its borders, and the transmission projects needed to bring those resources to load centers.

RETI, as currently envisioned, will have three phases. In the first phase CREZs will be identified and ranked based on renewable resource potential, generation and transmission costs, and the value of energy and capacity produced. In the second phase the analysis will consider generation and transmission project siting constraints to produce a conceptual renewable resource transmission plan with recommended CREZ development scenarios. Environmental, and technological constraints to transmission and generation project siting will be considered. Conceptual transmission plans will be developed in coordination with the CAISO and publicly owned utilities for each CREZ. In the third phase detailed transmission plans will be developed which include a consensus determination of need that is reflected in the transmission plans.

[38] Armando Perez, Memorandum to ISO Governing Board, "Briefing on Generation Interconnection Process Reform Initiative", March 18, 2008, p. 3.

At the conclusion of Phase 3 the permitting process for each CREZ-driven transmission project will be initiated.

The proposed financing mechanism would initially roll-in the costs of these interconnection facilities through the transmission revenue requirement (TRR) of a Participating Transmission Owner (PTO) that constructs the facility. The cost of the facility would be reflected in the CAISO Transmission Access Charge (TAC), which is assessed on a gross load basis. Each generator that interconnects would be responsible for paying its pro rata share of the transmission revenue requirement associated with the line which is calculated based on the maximum capacity of the generator relative to the capacity of the line.[39] Until the line is fully subscribed, all users of the grid (i.e., load) would pay the cost of the unsubscribed portion of the line, through its inclusion in the TAC. Once the facilities are constructed, generators of any fuel type would be eligible to interconnect and contract for unsubscribed capacity, reducing the potential for stranded costs.

The CAISO proposes the following eligibility criteria for the proposed rate treatment for the interconnection facilities:

(1) The costs of the interconnection facility – which is a non-network facility – would not otherwise be eligible for inclusion in the CAISO's TAC;

(2) The project must provide access to an "energy resource area"[40] in which the potential exists for the development of a significant amount of location-constrained energy resources;

(3) The project must be turned over to the CAISO's operational control;

(4) The project must be a high-voltage facility designed primarily to serve multiple location-constrained resources that will be developed over a period of time;

(5) To be eligible for this financing treatment, a project would have to be evaluated and approved by the CAISO in the context of a CAISO transmission planning process, thereby ensuring that the project will result in a cost effective and efficient interconnection of resources to the grid;

(6) To limit the cost impact of the proposal on ratepayers, there would be an aggregate cap on the total dollars associated with the multi-user interconnection facilities that could be included in TAC rates at any one time. Specifically, the total investment in the interconnection facilities that can be included in Transmission Revenue Requirements (TRRs) and the TAC cannot exceed 15 percent of the sum total of the net high-voltage transmission plant of all PTOs, as reflected in their TRRs and

[39] California ISO, Revised Draft LCRI Tariff Language, p. 6. http://www.caiso.com/1816/1816d22953ec0.html

[40] The CAISO defines an energy resource area as a region in California, to be identified by the CEC or other state agency that holds the potential for development of a significant quantity of location-constrained resources and that is not readily accessible to the CAISO transmission grid.

in the TAC; and

(7) To limit the risk of stranded costs due to abandoned investment, the project must demonstrate adequate commercial interest by satisfying the following two-prong test before actual construction can commence: (a) a minimum percentage of the capacity of the new interconnection facilities – an order of magnitude of 25 to 30 percent – must be subscribed through executed Large Generator Interconnection Agreements (LGIAs); and (b) there must be a tangible demonstration of additional interest in/support for the project – an order of magnitude of 25 to 35 percent – above and beyond the capacity covered by LGIAs[41].

In January, 2007, the CAISO filed a Petition for Declaratory Order with the FERC[42] seeking conceptual approval of the RETI financing mechanism for the construction of interconnection facilities to connect location-constrained resources to the CAISO grid. Intervenors were mostly supportive of the CAISO proposal, however, issues such as undue discrimination, open-access concerns, and cost allocation were raised by some.

In April 2007, FERC issued an Order[43] finding that CAISO's proposed rate treatment is not unduly preferential or discriminatory and would be just and reasonable, noting that the difficulties faced by generation developers seeking to interconnect location-constrained resources are real, are distinguishable from the circumstances faced by other generation developers, and such impediments can thwart the efficient development of needed infrastructure. FERC also found that the CAISO's proposal is consistent with its policies that recognize and accommodate the unique circumstances of renewable resources.

The CAISO is currently engaged in a stakeholder process with interested parties to develop appropriate transmission tariffs for this new category of transmission facility. As a result, there is uncertainty regarding how RETI will be implemented. For example, it is not clear how responsibility for transmission cost over runs will be allocated. The CAISO plans to file its proposed reforms with FERC in late spring 2008.

In March 2008 the RETI Phase 1A Draft Report was issued, evaluating the renewable resource potential, value of energy and capacity offered by these renewable resources and their generation and transmission costs.

4. United Kingdom: Transmission Access Review

4.1 Introduction

In May 2007, the UK Department of Trade and Industry (DTI) issued "Meeting the Energy Challenge: A White Paper" (Energy White Paper) which focused on "tackling climate change by

[41] See Standard Large Generator Interconnection Agreement, Appendix V, CAISO FERC Electric Tariff, Third Replacement Vol. 1 (CAISO LGIA).
[42] Docket No.EL07-33-000
[43] Docket No. EL07-33-000

reducing carbon dioxide emissions both within the UK and abroad; and ensuring secure, clean and affordable energy as we become increasingly dependent on imported fuel."[44] The Energy White Paper announced a review, to be led jointly by Office of Gas and Electricity Markets (Ofgem), the regulator, and DTI, of the technical, commercial and regulatory framework for the development of new transmission and the management of the grid as the proportion of renewable generation on the system grows.

The chief aim of conducting a transmission access review (TAR) is to support the government's goal of 20 percent of electricity supplied by renewable generation by 2020 and any European Union targets. The review is exploring a range of issues associated with the technical, commercial and regulatory arrangements of the current transmission access framework.

Because of the geographical concentration of wind resource in Great Britain, there are challenging connection issues given the need to accommodate large amounts of wind generation. DTI recognized the need for greater transmission investment for renewables in the Energy White Paper:

> "The plans for additional investment in the transmission system recognize that there is a large volume of primarily wind electricity generation that will connect to the transmission system over the coming years. However, the exact volume and timing are uncertain and, as a result, connection of these renewable generation stations presents new challenges."[45]

4.2 Institutional Context

The UK currently has around 76,000 MW of electricity generation capacity with annual consumption of about 350 TWh and winter peak demand of about 63,000 MW. It has a diverse electricity generation mix. In 2006, 36% was generated by gas, 37% from coal, 18% from nuclear, and 4% from renewables. The remainder comes from other sources such as oil-fired power stations and electricity imports from the continent.[46]

The grid is operated by the System Operator (SO), National Grid Electricity Transmission (NGET) plc and is responsible for overseeing and managing the flow of electricity across the whole Great Britain transmission network, including the elements owned and maintained by Scottish Power Transmission Limited (Scottish Power) and Scottish Hydro-Electric Transmission Limited (Scottish Hydro). NGET is also required to co-ordinate the connection process.

Electricity transmission assets are owned and maintained by regional Transmission Owners (TOs): NGET for England and Wales, Scottish Power for southern Scotland, and Scottish Hydro for northern Scotland. These companies are responsible for building and maintaining "safe and efficient" networks and are regulated by Ofgem.

[44] U.K. Department of Trade and Industry, Meeting the Energy Challenge: A White Paper on Energy (Energy White Paper), May 2007, p.6.
[45] DTI, Energy White Paper, p.139
[46] DTI, Energy White Paper , p.127

The effective functioning of Great Britain's electricity market is overseen by Ofgem which is responsible for ensuring competition in the wholesale and retail markets and regulating the network industries. Ofgem along with the Department for Business, Enterprise and Regulatory Reform (BERR formerly DTI) ensures that the three TOs provide access to the GB transmission system to parties on a transparent, non-discriminatory basis.

Access to the transmission network is governed by the Connection and Use of System Code, a framework for connection to, and use of, the high voltage transmission system. Ofgem is responsible for making decisions on any proposed modifications. NGET currently offers standard access products (commercial arrangements which offer varying degrees of certainty as to the level of access to the network). These products have been developed for traditional forms of electricity generation.

All generation connected to the transmission system is required to pay charges according to investment cost reflective pricing principles – the greater the cost impact to the network the higher the transmission charge. These Transmission Network Use of System (TNUoS) charges are therefore based on the cost of network investment, largely defined by transmission companies' planning investment criteria.[47] The Great Britain Supply Quality and Security Standard drives the design of the transmission network and was developed for systems with conventional generation. With generation responsible for a share of transmission costs and a market-based system, its underlying philosophy is centered on ensuring that transmission capacity is sufficient so that generators in remote areas are not unduly restricted from contributing to security of supply of local loads. As such, TO investment decisions are driven largely by generator connection requests.

The SO and each TO are subject to regular price control reviews. Every five years Ofgem approves a specific revenue target for each company. An important element of this review is the capital budget and its ability to accommodate required system reinforcements without additional regulatory pricing approvals.

The UK has a renewable obligation (RO) target that renewables represent 10% of electricity supplies by 2010, with an aspiration for this level to double by 2020.[48] The RO places this obligation on licensed electricity suppliers (i.e., retailers or load serving entities). The RO is administered and enforced by Ofgem.

More than 2,000 MW of wind are now connected to the grid – with the first 1,000 MW taking about 14 years to become operational and the second only 20 months. A further 1,260 MW of renewables capacity is under construction; 4,600 MW has been approved; and 11,400 MW is in planning processes across the UK. Ofgem has approved capital spending of over £500 million

[47] These TNUoS charges are based on a single peak demand condition and the location specific network charges are evaluated on the basis of the impact that individual users have on the need for transmission under this condition. Assuming that all generators operate during peak conditions, generators connected in the same area would have the same impact on the transmission network investment and hence will have the same TNUoS charges.

[48] DTI, Energy White Paper, p.14

for transmission system upgrades to enable the development of wind projects in Northern England and Scotland. Not surprisingly, this level of renewable project development is creating problems for the connection of renewable generation.

The major issues include the uncertainty faced by generators regarding cost responsibility for network reinforcements that their project may trigger and the effective reservation of valuable transmission capacity by speculative projects in the queue. In addition, the volume of connection requests is bogging down the connection process. The Energy White Paper indicated that there are a number of challenges to speeding up the rate of connection of renewable generation including:

- "managing more efficiently the queue of developers waiting for connection;
- the need for reform to the arrangements for access of renewable generation to the transmission grid;
- ensuring the technical standards for the grid do not disproportionately burden renewable generators; and
- ensuring that in the longer-term we have a framework that continues to meet the grid-related challenges associated with an increasing proportion of renewable generation."[49]

The government's strategy "continues to be based on the principle that independently regulated, competitive energy markets, are the most cost-effective and efficient way of delivering our objectives."[50] Therefore, its TAR proposals (discussed below) for developing new transmission for renewable generation have a strong market orientation. For example, one of the principles refers to the need for transmission companies have appropriate incentives to respond to the long term demand for access signaled by generators, to invest ahead of full user commitment, and to deliver new connections on time. Additionally, the proposed access models anticipate using market-based mechanisms to deliver access, and/or locational marginal pricing.

Following publication of the Energy White Paper in 2007, Ofgem and the BERR convened a joint review of the current framework for access to the transmission system, noting that "[t]he volume of generation wishing to connect to the transmission system is substantial and the time taken to build the required infrastructure means that renewable generation in certain parts of the country is facing severe delays in gaining access. There are areas of the system which are physically constrained as a result of the delay to reinforcement works, which has consequences for network users and consumers who ultimately pay the costs of constraining generation off the system."[51]

In addition to reevaluating the access arrangements, Ofgem has increased the allowed investments in transmission system reinforcements and connection facilities for the period of 2007-12. These arrangements incorporate considerable allowances for capital investment for TOs, totalling over £4.3billion for the electricity grid, representing an increase of 160% over the previous five-year price control period. The price control framework allows "the transmission companies flexibility under certain conditions to make further investments automatically without

[49] DTI, Energy White Paper, p. 160.
[50] DTI, Energy White Paper, p. 8
[51] Ofgem website, http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Pages/Traccrw.aspx

the need to reopen the entire price control review. This mechanism will be of particular benefit to renewable generation."[52]

The Energy White Paper also made two proposals that could have long-term implications related to the cost responsibility for network transmission charges, as well as for transmission investment requirements for renewable generation. With respect to cost responsibility, as discussed, generation connected to the transmission system is required to pay charges according to investment cost reflective pricing principles. Work sponsored by DTI suggests that renewable generation may drive the need for transmission reinforcement to a lesser degree than conventional generation – which implies transmission charges should be lowered. This is explained by DTI:

> "First, the contribution of renewable generation to security of supply is potentially very different from conventional generation (expanded below). Although wind generation may displace energy produced by conventional plant, its ability to displace conventional network capacity is limited even at substantial penetrations, due to its variability. (At the low penetrations we currently have, supply displacement is similar to that of capacity displacement.) Therefore, the need for transmission network capacity to enable wind generation to contribute to security of supply would be less than conventional plant.
>
> Second, when calculating the proportion of the utilisation of transmission capacity by wind and conventional plant, during peak-flow condition on a probabilistic basis, wind occupies less transmission due to its low load factors (around 35%). Wind occupies the same capacity when generating but is less likely to be operating at peak."[53]

Concerning transmission investment requirements for renewable generation, the Energy White Paper suggested that current transmission reinforcement and connection standards have the potential to overstate investment requirements for renewable generation. NGET's transmission investment standards are designed to ensure a "safe and secure" transmission network under a wide range of contingencies. A report sponsored by the DTI shows that application of these standards could be inappropriate in the case of renewables. The system may be "over-engineered" in some instances. Specifically, DTI is suggesting that because conventional fossil resources will be operating more in a reserve mode (i.e., when renewable resources are not available), the system doesn't need to be built to accommodate both resources. DTI notes that this approach may offer the added benefit of allowing renewable generation to connect to the system prior to the reinforcements being complete, with the recognition that constrained-off payments will increase in this period.

[52] DTI, Energy White Paper, p. 159.
[53]DTI, Annex E, p. 3.

4.3 UK TAR Framework

A final report on TAR was released on June 26th. [54] The report includes actions that will allow faster connection of some renewable generation to the Grid in the short-term, steps to introduce new, enduring grid access arrangements that allow faster connection and expansion of Grid capacity, and measures to identify the new transmission infrastructure necessary to meet the UK share of the 2020 EU renewable energy targets and new financial incentives on the transmission companies to deliver that capacity. Alongside the TAR report, the Government published its Renewables Energy Strategy Consultation document. This consultation exercise provides an opportunity to respond to the issues covered in the report as well as on wider renewable energy policy issues.

The focus of the following discussion of the final TAR report is on the enduring grid access arrangements and the new transmission infrastructure intended to enable the development of renewable generation. In general, the report sets out high-level principles, three possible access models and associated issues, access model assessment criteria, and the steps to implement access reforms.

The final TAR report offered the following five high level principles for the access arrangements:[55]

- "New generation projects should be offered firm connection dates, reasonably consistent with the development time of their project.
- Generators wanting long term, financially firm access to the system need to make long term financial commitments.
- Transmission companies need to have appropriate incentives to respond to the long term demand for access signaled by generators. They need the freedom and incentives to invest ahead of full user commitment. They also require appropriate incentives to deliver new connections on time and to innovate so that they can deliver as much capacity as possible from existing assets.
- Access rights need to be more clearly defined and all generators need to be offered choice about how they access the system. This choice will need to include long term fixed price access rights that guarantee long term access in return for a commitment to pay for capacity, and shorter term, more flexible access rights.
- Transmission capacity should be 'shared', particularly as the amount of connected generating capacity increases in relation to transmission network capacity. This will lead to more efficient use of both existing and future capacity."[56]

The TAR Analytical Discussion Document[57] sets out three possible transmission access models for consideration by industry:

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[54] Ofgem and BERR, Transmission Access Review - Final Report, June 26, 2008.
[55] Ofgem and BERR, Transmission Access Review – Final Report, June 26, 2008, p. 2
[56] Transmission Access Review – Final Report, p. 12-13.
[57] TAR Analytical Discussion Document, April 2008, p.12

"•**Model A** - adopts a 'connect and manage' approach to transmission access in which the right to access the system is driven by the requirements of a connecting party. This reflects the model's primary focus of facilitating increased generation deployment.

• **Model B** - uses market-based mechanisms to deliver access to the party that values it most at any given time. This is done through the initial allocation and secondary trading of a range of access products. This includes firm access rights of different duration and the provision of a facility for generators to access the system through overrun arrangements.

• **Model C** - is based on a locational marginal pricing approach, which exposes all participants to the short run costs of transmission access in each half hour. The model maintains the separation of energy and capacity markets."[58]

The models can be differentiated based on: "whether the volume of access rights is system-driven or user-driven, and whether costs are socialised or met by the party that gives rise to them." Each modeled is viewed as potentially an improvement to the status quo given the objective of enhancing access to the transmission system for low carbon generation.

The TAR report provided only a high level review of each of the three models and identified a number of key issues associated with each of the models. The models were evaluated in terms of the impacts on the following areas: the environment, competition, security of supply, network investment, costs to consumers, implementation issues, and risks and unintended consequences.[59] The report noted:

- It is likely that operating costs would be higher under Model A because of the lack of efficient signaling through charges. The model provides only weak signals of the cost (or benefit) of locating where there are (or are no) existing constraints. However, some of these additional costs may be offset by a combination of greater renewable generation and lower total generation costs (due to a bias towards less capital intensive onshore wind as opposed to offshore wind);

- For Model A to be able to deliver this cost effective outcome, it must be combined with a timely network investment regime, otherwise constraint costs will escalate without delivering the benefit of additional generation;

- Model C may have the lowest cost and, arguably, the most efficient short-run signals for network utilisation and connection decisions. However, this is likely to be offset by lower overall renewable generation volumes if the additional volatility and uncertainty in charges faced by generators increases the risk of connection, thereby reducing the delivery of renewable generation. The materiality of this risk is hard to quantify accurately. If it is present then it may manifest itself in one of several ways:
    - Lower actual generation connection and therefore, by implication, lower renewable output;
    - Slower generation connection; or

[58] Transmission Access Review – Final Report, p. 14.
[59] Transmission Access Review – Final Report, p. 14-20.

- Higher cost of generation or of renewable support (reflecting higher cost of capital) and, by implication, an increase in the cost to consumers relative to the same volume and mix of capacity being delivered under Model A; and

Finally, the TAR report establishes the steps to be taken to achieve the transmission access reforms, noting that it is conceivable - given the need for proper process - that a new regime may not be delivered until April 2010. This could be further delayed if any decision taken by Ofgem is subject to legal challenge.