



**UE21704**

**IN THE MATTER of an Inquiry into  
Current and Pending Electricity  
Transmission Access Rules in Other  
Jurisdictions.**

**Report to  
Executive Council**

November, 2003

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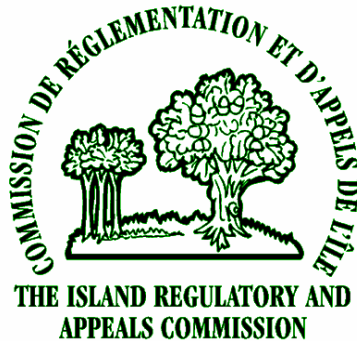
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## Letter of Transmittal



November 14, 2003

Hon. Jamie Ballem  
Minister of Environment & Energy  
Government of Prince Edward Island  
P.O. Box 2000  
Charlottetown, PE C1A 7N8

Sir:

### Re: Inquiry into Current and Pending Electricity Transmission Access Rules

Pursuant to Section 23 of the *Maritime Electric Company Limited Regulation Act*, R.S.P.E.I. 1988, Cap. M-1.2, and Order in Council EC2003-467, our Report to Executive Council in this matter is enclosed.

Yours very truly,

*(Sgd.) Ginger Breedon*

Ginger Breedon  
Chair & Chief Executive Officer

# 1. Introduction

By Order in Council EC2003-467, the Lieutenant Governor in Council directed the Commission, pursuant to Section 23 of the *Maritime Electric Company Limited Regulation Act*, R.S.P.E.I. 1988, Cap. M-1.2, to inquire into, and report on, the following matters relating to electricity generation and transmission access:

- Current electricity generation and transmission access opportunities (direct or indirect) open to cities, towns or municipalities as well as large industrial customers within Nova Scotia, New Brunswick and the New England States;
- Pending and probable changes to current electrical generation and transmission access within these jurisdictions;
- Current or contemplated transmission access opportunities in other jurisdictions which do not now exist on P.E.I.; and
- Any other matter the Commission may consider relevant to the issue.

The Lieutenant Governor in Council further directed that the Commission's report be filed by November 14, 2003.

# 2. Process

As part of the Inquiry, the Commission retained the services of John Murphy, M.B.A., P.Eng., ("Murphy" or "Research Consultant") a consultant with extensive experience in the area of electric utility regulation, to provide research assistance to the Commission and to prepare a detailed report on transmission access rules and processes provided in other jurisdictions. More specifically, Murphy was directed to:

- (1) Provide a detailed (chronological) history of electricity generation and transmission access within the framework of initiatives by the United States Federal Energy Regulatory Commission (FERC), including the impact these FERC initiatives have had on Canadian Jurisdictions.
- (2) Provide any available information relating to the possible future direction of FERC on these matters, based on any known work-in-progress and in the planning stages. Include discussion relating to what may have been learned by past mistakes, and corrective action that may be taken by FERC.
- (3) Provide a discussion relating to changes that were required in state and provincial legislation as a result of initiatives by FERC.
- (4) Provide a general discussion regarding the role of Municipal Electric Utilities throughout North America, including their access to generation and transmission assets owned by other utilities.
- (5) Summarize the regulatory framework relating to generation and transmission access by municipal utilities and large industrial customers, and pending and/or probable changes relating to such access:
  - i. In general terms for jurisdictions in the US and Canada.
  - ii. In detailed terms for Nova Scotia, New Brunswick and the New England States.
- (6) Provide information regarding the methodology used to assign costs to utilities for use of generation and transmission facilities owned by other utilities:
  - i. In general terms for jurisdictions in the US and Canada. (Some Specific Examples)
  - ii. In detailed terms for Nova Scotia, New Brunswick and the New England States.
- (7) Summarize transmission access opportunities existing or being contemplated in other jurisdictions which do not currently exist on P.E.I.

(8) Report on any other related matters relevant to the investigation.

The Research Consultant's report to the Commission is included herein as Appendix 2.

### 3. Background

- **What is Transmission Access?**

Electricity provided to most consumers by a public utility is transmitted from the source or point where it is generated or purchased via a system of transmission and distribution lines. The transmission system is generally comprised of high voltage lines and equipment of a public utility that run between the sources or points of supply and the points at which electricity is transformed to lower voltages for further distribution to customers.

Most customers of a public utility obtain their electricity from lower voltage distribution lines. Certain large customers may connect directly to the higher voltage transmission system. Public utilities themselves interconnect at the transmission level and buy and sell electricity for resale.

Recent federal initiatives in the United States and the desire on the part of Canadian public utilities to sell into the US market have resulted in the adoption, in many jurisdictions in Canada, of a US requirement for open transmission access. Under the US requirement, public utilities and, in certain instances, large customers can access another utility's transmission system for the purpose of buying and selling electricity from someone other than the utility that owns the system.

In simple terms, open transmission access means that a utility must provide transmission services over its transmission system to another utility or large customer where that other utility or large customer wants to purchase or sell electricity from or to someone else. This, in turn, means that, where adequate transmission facilities are already available, there is no need for other utilities or large customers to build additional transmission lines and equipment. Open transmission access also allows for access to generating facilities that might not otherwise be readily available.

Under open transmission access, transmission service is provided at a rate (i.e. a cost to the user) that fairly compensates the owner of the transmission system. Open transmission access is fundamental to the restructuring of the electricity supply industry which is currently underway in most areas of North America.

This report is limited to the issue of open transmission access. The broader and more complex issue of industry restructuring, with a move away from vertically integrated monopoly suppliers of generation, transmission and distribution services, is beyond the scope of this inquiry.

## ● Historical Development

Rules either now established or those currently under development or consideration in Canada for open transmission access generally follow the requirements of the US Federal Energy Regulatory Commission (“FERC”)<sup>1</sup>. FERC’s involvement in transmission access began in 1996 when it issued Orders 888 and 889 directing utilities under its jurisdiction to file Open Access Transmission Tariffs (OATTs) allowing for non-discriminatory open access to transmission systems by third parties.

In Canada, utilities operating in the majority of Canadian provinces have either implemented, or will soon implement, FERC compliant OATTs. In essence, FERC requirements must be met by Canadian utilities wishing to access the US transmission network and, in effect, the US power market. It is generally believed that the application of uniform rules and standards in the area of transmission access—whether FERC mandated or not—should result in long-term benefits to utilities and, ultimately, consumers through easier and fairer access to generation resources available in other jurisdictions.

The basic requirements of a FERC compliant OATT are described by the Research Consultant this way:<sup>2</sup>

*FERC follows generally accepted rate making principles similar to [that which] any jurisdiction would be expected to develop on its own initiative.*

*The objectives relating to Open Access Transmission are:*

- (1) All customers must be given access on the same terms and conditions;*
- (2) Transmission Rights must be allocated fairly; and*
- (3) Rates must be consistent with FERC’s Transmission Pricing Policy Statement.*

*FERC’s Transmission Pricing Policy Statement issued on October 26, 1994 specified five principles regarding the pricing of transmission services.*

*Transmission Pricing:*

- (1) Must meet the traditional revenue requirement.*
- (2) Must reflect comparability.*
- (3) Should promote economic efficiency.*
- (4) Should Promote Fairness, and*
- (5) Should be practical.*

*FERC defines 3 steps in the rate design process as:*

- *Establishment of the revenue requirement*
- *Allocation of the revenue requirement to various services, and*
- *Recovery of costs from each customer class*

The final requirements for a FERC-compliant OATT continue to evolve. In addition to the establishment of an OATT, utilities are required to establish and maintain an open access same-time information system (OASIS) where it must post, for the use of its transmission service customers, information on the status of the transmission system as well as available capacity and pricing. FERC’s recently announced Wholesale Power Market Platform requires, among other things, utility

<sup>1</sup> Detailed information on FERC’s influence in the Canadian marketplace can be found in Appendix 2.

<sup>2</sup> Appendix 2, p.3

membership in an independent regional transmission organization (RTO) or independent system operator (ISO) who will be responsible for the overall operation of the transmission system and the administration of the transmission tariff.

In summarizing the evolution of open transmission access, the Research Consultant notes as follows:<sup>3</sup>

*In a sequence of orders, FERC has attempted to progressively work towards a set of market rules for transmission access that will provide fair and non-discriminatory access to all.*

*The principles and pricing policies used by FERC in the approval process for the Open Access Transmission Tariff follow generally accepted rate making principles utilized by most regulatory agencies. Following FERC's approach for setting transmission tariffs in order to meet reciprocity requirements has not been found to be a burden for Canadian utilities. The entire North American Continent, including Canada and Mexico generally have or are in the process of implementing Open Access Transmission Tariff designs that are compliant with FERC principles.*

*Rules relating to the controversial subject of Transmission Rights are being reviewed with the objective of reaching common treatment and fairness to customers based on existing contract rights and historical usage.*

*There has not been a requirement, to date, to approve an Open Access Transmission Tariff for Prince Edward Island. However, it is important that the principles contained in the FERC process and being adopted throughout most of North America, including fairness to all customers, be taken into account during the determination of rates for bilateral contracts for transmission usage in Prince Edward Island.*

It is clear from the Research Consultant's work that the concept of open transmission access is being adopted throughout North America.

## 4. Open Transmission Access Availability

### • New England

With the exception of the State of Vermont, New England has open transmission access with FERC compliant OATTs and both wholesale and retail competition. Municipal utilities and all large industrial customers may contract with any generating or marketing company for their supply of electricity, with transmission services available over an existing transmission system under an OATT.

In Vermont, transmission access is available at the wholesale level and municipal utilities may purchase power and take delivery of power under an OATT.

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<sup>3</sup> Appendix 2, p.5

## ● New Brunswick

Effective September 30, 2003, New Brunswick's three municipal electric utilities and industrial customers served off of NB Power's transmission system at the 69 kV or higher voltage level have the option to purchase electricity from any supplier, through the existing transmission system, based on an OATT. Similarly, any power producer in New Brunswick located near the NB Power transmission system has access to the transmission system and can sell its electricity to any customer on the power grid. Electricity can be sold into the US market provided the exporter holds a power marketing authority license from FERC.

## ● Nova Scotia

In a report<sup>4</sup> released on October 23, 2003, the Nova Scotia Electricity Marketplace Governance Committee (EMGC) issued a number of recommendations to the Government of Nova Scotia on issues relating to open transmission access, among others. At the present time, Nova Scotia's principal supplier of electricity, Nova Scotia Power Inc. (NSPI) does not have an OATT.

The EMGC has initially recommended that a non-FERC compliant OATT be established by NSPI and that it be limited to the Province's municipal utilities, which comprise only 1.6% of the Province's peak demand for electricity. The EMGC has also recommended that the Government of Nova Scotia undertake a detailed analysis of the costs and benefits associated with broader electricity competition in Nova Scotia.

It is important to note that Nova Scotia, through the EMGC and the Province's Energy Strategy<sup>5</sup>, has adopted a gradual and cautious approach to both industry restructuring and open transmission access.

## ● Prince Edward Island

Since 1993, Maritime Electric's rates have been governed by the *Maritime Electric Company Limited Regulation Act*. Rates for Summerside Electric, which is owned by the City of Summerside, have been governed by the *City of Summerside Electric Utility Exemption Regulations* issued pursuant to the *Electric Power and Telephone Act*.

To date, there is has been no legislative or other requirement for either utility to develop an OATT.

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<sup>4</sup> Final Report, Province of Nova Scotia Electricity Marketplace Design Committee, Oct, 2003  
<http://www.gov.ns.ca/energystrategy/emgc>

<sup>5</sup> *Seizing the Opportunity*, Nova Scotia's Energy Strategy, 2001  
(<http://www.gov.ns.ca/energy/inside.asp?cmPageID=140>)

## 5. Conclusions

The work of the Commission's Research Consultant reveals that the issues surrounding the establishment of a FERC compliant OATT are both complex and evolving but also inevitable. Based on this work, it is apparent to the Commission that:

1. it will be necessary to move towards open transmission access in Prince Edward Island with the eventual goal of establishing a FERC compliant OATT. As Prince Edward Island is interconnected with the North American power grid, and as both Maritime Electric and Summerside Electric currently rely heavily on electricity imports to satisfy the needs of their customers, open transmission access will be necessary to access future electricity markets; and
2. the extent to which an OATT should apply to either Maritime Electric or Summerside electric, or to both, and whether open transmission access should be made available to large commercial or industrial customers of either or both utilities are matters that will require careful planning, analyses and public input.

The Commission also notes that the submarine cable interconnection for electricity transmitted between the mainland and Prince Edward Island is owned by the Province of Prince Edward Island and leased to Maritime Electric pursuant to an Interconnection Lease Agreement. In the Commission's view, the submarine cable interconnection should be considered an extension of the Maritime Electric transmission system in any possible future development of a Maritime Electric OATT.

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## Appendix 1

Copy of an Order of His Honour the  
Lieutenant Governor in Council dated 26 August 2003

**EC2003-467**

**MARITIME ELECTRIC COMPANY LIMITED REGULATION ACT  
PETITION TO INQUIRE INTO AND REPORT ON  
ELECTRICITY GENERATION AND TRANSMISSION ACCESS**

Pursuant to section 23 of the *Maritime Electric Company Limited Regulation Act* R.S.P.E.I. 1988, Cap M-1.2, Council directed the Island Regulatory and Appeals Commission to inquire into, and to report to Executive Council by 14 November 2003 on, the following matters relating to electricity generation and transmission access:

- current electricity generation and transmission access opportunities (direct or indirect) open to cities, towns or municipalities as well as large industrial customers within Nova Scotia, New Brunswick and the New England States;
- pending and probable changes to current electrical generation and transmission access within these jurisdictions;
- current or contemplated transmission access opportunities in other jurisdictions which do not now exist on P.E.I.; and
- any other matter the Commission may consider relevant to the issue.

*(Sgd) Lynn E. Ellsworth*

Lynn E. Ellsworth  
Clerk of the Executive Council

Appendix 2

**Review of  
Open Access Policies and Practices  
In North America**

**Prepared for the Island Regulatory and Appeals Commission**

**John Murphy MBA, P.Eng.**

**October 23, 2003**

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## **Executive Summary**

### **Overview**

During the past twenty-five years, the electric utility industry in North America has slowly yet continually moved from a vertically integrated monopoly structure to one of competition and open access. Competitive supply, at least at the wholesale level, is readily available in the majority of jurisdictions based on open access to transmission facilities. During the transition from a monopoly to a competitive market structure, it has become apparent that the profit interests of transmission owning utilities has sometimes outweighed the intent of open access. This has required the development and adoption of increasingly more stringent rules and regulations to ensure open and non-discriminatory access to transmission by all market participants.

Open access for electricity transmission in North America began in 1996 when the U.S. Federal Energy Regulatory Commission (FERC) issued Orders 888 and 889 directing utilities to file Open Access Transmission Tariffs (OATTs). This, for the first time, provided an opportunity for buyers and sellers of electricity to enter into contracts independently from the incumbent utility, and to attain access to the utility's transmission network to serve the load. Furthermore, access was to be provided by the transmission owner on a non-discriminatory basis and at a reasonable level based on the cost of providing the transmission service. Initially such access was directed towards wholesale customers that purchase electricity for resale (also known as Load Serving Entities (LSEs)), but was soon expanded in many jurisdictions to include other large customers.

Recent initiatives by FERC have included a proposed "Standard Market Design" which after an extensive consultation process was revised to become a proposed "Wholesale Power Market Platform" as set out in FERC's white paper of April of 2003. These initiatives support FERC's objective to continue making the rules relating to open transmission access more fair for all market participants. Legislation has been passed in both the U.S. House and U.S. Senate during 2003 supporting FERC's objectives.

Canada is intrinsically linked to U.S. power markets through various connections to the North American grid. While there are undercurrents of political concern regarding Canada's sovereignty over its energy future, electricity exports depend on meeting reciprocity requirements set out by FERC. Furthermore, reliability considerations are becoming increasingly important as the frequency of major outages provide acute reminders of the fragility that exists when grid operations approach their limits, something that is happening more frequently in both North America and other parts of the world.

Most Canadian electric utilities understand that in the future, rules for electricity access for the entire North American grid will be largely defined by FERC. In addition to meeting the reciprocity requirements, security of supply dictates that some entity must provide the overall leadership in order for the grid to operate, both economically and technically, in the best interest of all. There will be ongoing opportunities for interested parties to present Canadian interests and views for defining market rules to FERC at various proceedings.

On June 19, 2003, the New Brunswick Board of Commissioners of Public Utilities (PUB) approved an Open Access Transmission Tariff for NB Power with an effective date of September 30, 2003. This tariff is available for municipal wholesale and industrial customers served from NB Power's transmission system (69 kV and above). In New England both wholesale and retail customers have open access to the transmission grid, with the exception of Vermont which has not been active with electricity restructuring and therefore only wholesale customers have access as provided under FERC's jurisdiction.

Nova Scotia had initially indicated a willingness to participate in the New England Transmission Organization (RTO). However, the October 2003 Final Report by the Nova Scotia Electricity Marketplace Governance Committee recommends that only the six municipal utilities should be granted open transmission access initially, and that Nova Scotia should progress slowly with regard to opening the market to transmission access.

In Prince Edward Island there has not been a requirement for Maritime Electric Company Limited (MECL) to file an Open Access Transmission Tariff. Nevertheless, it is important for the assurance of proper rate levels for transmission services that FERC's principles be considered when establishing tariffs for any transmission contracts in Prince Edward Island.

### **FERC Principles and Pricing Policy**

Following the FERC framework to the extent necessary to satisfy reciprocity requirements has not presented a problem for those Canadian jurisdictions that have established open access transmission tariffs. FERC follows generally accepted rate making principles similar to what any jurisdiction would be expected to develop on its own initiative.

The objectives relating to Open Access Transmission are:

- (4) All customers must be given access on the same terms and conditions;
- (5) Transmission Rights must be allocated fairly; and
- (6) Rates must be consistent with FERC's Transmission Pricing Policy Statement.

FERC's Transmission Pricing Policy Statement issued on October 26, 1994 specified five principles regarding the pricing of transmission services. Transmission Pricing: (1) Must meet the traditional revenue requirement. (2) Must reflect comparability. (3) Should promote economic efficiency. (4) Should Promote Fairness, and (5) Should be practical.

FERC defines 3 steps in the rate design process as:

- Establishment of the revenue requirement
- Allocation of the revenue requirement to various services, and
- Recovery of costs from each customer class.

This approach by FERC follows the framework for establishing "just and reasonable" and "fair and equitable" rates as discussed in detail in a previous Inquiry on Economic Regulation undertaken by the Island Regulatory and Appeals Commission in May, 2003.<sup>1</sup>

### **Transmission Rights**

The allocation of Transmission Rights is very important in establishing fairness of rates for customers in open access transmission tariffs. A firm transmission right assigns priority to customers at times when demand exceeds the transfer capacity of the transmission grid, and when higher cost alternative energy must be acquired in order to serve all loads (periods referred to as transmission congestion). Transmission Rights enable Load Serving Entities (wholesale customers who purchase electricity for resale, i.e. the City of Summerside) to guarantee continuous supply to their customers regardless of the level of transmission congestion. The holder of such rights normally does not pay additional costs when there is congestion, and if it relinquishes usage during times of congestion, it will normally receive compensation from whatever party uses its rights.<sup>2</sup>

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<sup>1</sup> "See Economic Regulation for Electric Utilities History, Rationale and Practices", May 15, 2003. Appendix A, LR3 Principles for Regulation and Methodology for Setting Rates – Summary from "Principles of Public Utility Rates" by Bonbright, Danielsen and Kamerschen. Second Edition March 1998. Public Utility Reports, Inc., Vienna, Virginia.

<sup>2</sup> Some markets (such as ISO New England) use a financial transmission right, which differs from a "firm" or "physical" right in that it offers a hedge against price volatility rather than a guarantee of a physical path.

FERC proposes that eligible customers be served by a single Network Access Service tariff that would have two components. An Access Right (the right to move power between any two points on the system, the costs for which would be recovered by an access charge), and a Transmission Right (the right to a predetermined price for service between two specific points on the system).

There is ongoing discussion regarding what is the fair way to make initial allocations of transmission rights to Load Serving Entities (LSEs). Following extensive consultation with the industry, FERC has determined that fairness in the allocation of transmission rights is best achieved on the basis of historical usage. In its April 28, 2003 White Paper, FERC concluded that it wanted to ensure that “existing customers retain their existing transmission rights and retain rights for future load growth.” FERC proposes that in its Final Rule, transmission rights “would be allocated according to existing contracts and existing service arrangements in order to hold customers harmless”.<sup>3</sup> In all instances observed, it is proposed that transmission rights be allocated at the wholesale level, not to individual retail customers.

FERC’s views on allocation of transmission rights based on historical usage becomes increasingly important for Prince Edward Island as the cable link with New Brunswick experiences increased periods of congestion. There are two Load Serving Entities on Prince Edward Island, Maritime Electric and the City of Summerside. Historical transmission usage by these LSEs could be argued to apply to both the cable link from New Brunswick and other transmission facilities on the Island. Although the City of Summerside may have been executing the majority of such usage indirectly through bundled tariffs for electricity purchased from Maritime Electric for resale to its customers, it all represents the “historical usage” of Summerside as an LSE. Customers in Summerside have been paying (within their rates) a portion of both fixed and variable costs associated with all transmission facilities used by Maritime Electric to serve Summerside.

There has been extensive public debate in other jurisdictions in order to develop transmission tariffs and assign transmission rights in a way that satisfy objectiveness of fair and equitable rates and access for all users. Allocation of and charges for transmission usage in PEI should satisfy these same tests of fairness, and be based on rationale as thorough and as robust as would be the case if PEI had fully open transmission access.

## **New England, New Brunswick and Nova Scotia**

### **New England**

The New England States, with the exception of Vermont, have both wholesale and retail competition, and all customers may access the transmission system in order to acquire power from elsewhere. In Vermont, where there has not been electricity restructuring, FERC’s jurisdiction still applies for transmission access at the wholesale level, and municipal utilities are eligible to purchase power elsewhere and take delivery under the Open Access Transmission Tariff structure, (though retail customers are not eligible for open transmission access).

### **New Brunswick**

As of Sept 30, 2003, New Brunswick’s three municipal electric utilities and its large industrial customers have the option to purchase their electricity from any supplier of their

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<sup>3</sup> FERC Wholesale Power Market Design Platform – White Paper – April 28, 2003. (pages 5 & 10)  
[http://www.ferc.gov/industries/electric/indus-act/smd/white\\_paper.pdf](http://www.ferc.gov/industries/electric/indus-act/smd/white_paper.pdf)

choosing based on open access to the transmission system of NB Power. At the same time, any power producer in New Brunswick located near the NB Power transmission system, has nondiscriminatory access to the network and can sell its electricity to any customer on the grid. The New Brunswick Market Design Committee has recommended that generators located in an area served at distribution voltage (below 69kV) receive a price equal to the utility's avoided cost, along with savings in line losses to the point of sale. It is expected that this recommendation will be included in the Market Rules that are being developed.

### **Nova Scotia**

Nova Scotia initially indicated a willingness to participate in the New England (Northeast) RTO. However, the final report of the Nova Scotia Electricity Marketplace Governance Committee released in October 2003, indicates a preference to allow open access only to the six municipal utilities which represent approximately 2% of the province's load. It is not proposed to include large industrial customers at this time, nor to adopt a fully FERC compliant Open Access Transmission Tariff.

### **Summary**

In a sequence of orders, FERC has attempted to progressively work towards a set of market rules for transmission access that will provide fair and non-discriminatory access to all.

The principles and pricing policies used by FERC in the approval process for the Open Access Transmission Tariff follow generally accepted rate making principles utilized by most regulatory agencies. Following FERC's approach for setting transmission tariffs in order to meet reciprocity requirements has not been found to be a burden for Canadian utilities. The entire North American Continent, including Canada and Mexico generally have or are in the process of implementing Open Access Transmission Tariff designs that are compliant with FERC principles.

Rules relating to the controversial subject of Transmission Rights are being reviewed with the objective of reaching common treatment and fairness to customers based on existing contract rights and historical usage.

There has not been a requirement, to date, to approve an Open Access Transmission Tariff for Prince Edward Island. However, it is important that the principles contained in the FERC process and being adopted throughout most of North America, including fairness to all customers, be taken into account during the determination of rates for bilateral contracts for transmission usage in Prince Edward Island.

## Introduction

The Federal Energy Regulatory Commission (FERC) Notice of Proposed Rulemaking (NOPR) on *Standard Market Design* (SMD), issued on July 31, 2002, signified the beginning of more clearly defined rules relating to electricity transmission access and tariff design. Controversy regarding FERC's initial proposal for SMD led to the initiative being reworked and presented by FERC in a "White Paper" dated April 28, 2003 as the *Wholesale Power Market Platform*. The changes incorporated seem to have succeeded in reducing opposition sufficiently so that FERC stands a good chance of penning a final order that will be acceptable by all market players. Through these efforts FERC is making it clear that it plans to play the lead role in electricity regulation in North America.

There is concern expressed at the State level in the US regarding loss of sovereignty, and similar concern at both the federal and provincial levels in Canada. Nevertheless, FERC will be taking the lead in making decisions on all of the major rules by which wholesale electricity market participants will be operating in the future. All participants will be provided an opportunity for input, but it is now recognized that if regions are allowed to implement inconsistent market rules, it will be impossible to attain the objectives of long-term price stability and reliability.

The evolution from a vertically integrated monopoly based electricity market to an industry where the majority of markets offer fully open access to both generation and transmission services began about twenty five years ago for generation and twelve years ago for transmission. To understand how FERC will define the rules for the future, we must pay close attention to the arguments presented to FERC by key players during the past two years and the legislation passed by the U.S. Congress and Senate during the summer of 2003.

The final order on the Wholesale Power Market Platform should be released by FERC within the next few months, and should set the stage for the next decade. Its objective is to define a way that benefits can be enjoyed by consumers while at the same time encouraging investors to build the additions to generation and transmission facilities needed to maintain the necessary levels of reliability.

This paper provides background relating to the move to open access, and describes the future as it is now unfolding, including insight into the rules that should soon be adopted.<sup>4</sup>

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<sup>4</sup> As always, the literature review is an essential part of the report. Most of the information presented in this report is based on the information gathered during the literature review process and captured in that section of the report. Readers who have an electronic version of this report are encouraged to click on the hyperlinks in that section and read any of the references found to be of particular interest.

## **PART 1**

### **Legislative and Regulatory Framework**

Major milestones on the road to open access in electricity generation and transmission may be identified as follows:

- (1) The Public Utilities Regulatory Policies Act (PURPA) in 1978 which permitted competition in generation.
- (2) The Energy Policy Act (EPAAct) of 1992 which explicitly stated the goal of a fully competitive electric industry.
- (3) FERC orders 888 and 889 in 1996, requiring utilities to offer open access to their transmission system.
- (4) FERC order 2000 in 1999 which directed the establishment of Regional Transmission Organizations, and
- (5) FERC's Notice of Proposed Rulemaking (NOPR) on Standard Market Design, July 31, 2001 and White Paper on the Wholesale Power Market Platform on April 28, 2003.

#### **The Public Utilities Regulatory Policies Act, 1978**

The deregulation of the electric power industry was initiated by the passage of the Public Utility Regulatory Policies Act (PURPA) which facilitated the emergence of certain electricity-producing companies called qualifying facilities (QFs), defined as small power producers and co-generators. QFs were to obtain at least 75 percent of energy inputs for electricity generation from renewable resources (geothermal, biomass, wind, solar, or hydro-power) and to have installed capacity of less than 80 megawatts.

FERC required the electric utility serving the location where a QF's generator was sited (the host utility) to purchase all output from the QF and to pay the utility's "avoided cost". This negated the need for QFs to access the transmission system for sales to third parties. In retrospect, many of the avoided cost contracts entered into under PURPA were priced above the long-term market value, resulting in excessive costs to electricity customers.

#### **The Energy Policy Act of 1992**

The Energy Policy Act (EPAAct) of 1992 gave FERC the authority to order utilities to provide transmission access in order to facilitate competition in wholesale power markets, further moving electricity generation away from its traditional highly regulated monopoly position. The EPAAct allowed holding companies to own exempt wholesale generators, which permitted them to market electricity to any wholesale customer outside their normal regulated utility territory anywhere in the U.S. In addition, PURPA was amended to allow the PURPA qualifying facilities to be owned by holding companies and by electric utilities in any geographic territory. However, the utilities still owned and controlled access to the transmission grid.

#### **FERC Orders 888 and 889, April 1996**

To allow the new generators to get their power to market and thereby compete with power generated by the utilities (based on its authority under the EPAAct) in April 1996 FERC approved Orders 888 and 889.

In Order 888 FERC directed electric utilities to file transmission tariffs allowing non-discriminatory, open access to third parties wanting to conduct wholesale transactions. Open Access Transmission Tariffs (OATTs) were required from all investor-owned utilities (and under reciprocity requirements most all utilities) that own, operate, or control electric

transmission used for interstate commerce. This provided for all other users to have similar access to transmission services (including ancillary services<sup>5</sup>) as did incumbent utilities, and under comparable terms and conditions.

Order 888 allowed customers to resell firm transmission capacity that they had contracted but were unable to use. Prior to this, the utility had the right to resell that capacity rather than the customers who initially had it under contract. Order 888 also allowed utilities, under certain conditions, to directly collect the stranded costs (i.e., costs for power priced above market prices) from wholesale customers. Order 888 made open access transmission an official FERC policy and ended decades of debate over whether electric utilities should be required to offer open access to transmission.

In Order 889 FERC required transmission-owning utilities to set up open access, same-time information systems (OASIS), using commercial software and Internet protocols. It also required transmitting utilities to enact 'codes of conduct' separating their marketing and merchant employees from transmission and reliability employees, thus creating two companies operating independently and separately from one another. Utilities were required to post market information and discounts simultaneously to all parties, providing all purchasers of transmission space accurate real time information on current loads and capacity available on the transmission system. It was intended to allow third parties the ability to manage transmission loads and obtain information on profit opportunities to the same extent as the utility owning the transmission lines.

### **FERC order 2000**

At the time FERC approved open access to transmission by Order 888, the concept of an Independent System Operator (ISO) at each utility was perceived to be the organizational structure that would coordinate transmission related activities. However, by 1999 trading volume had risen by more than 200 times and it became evident that regional solutions would be required. FERC recognized that the Order 888 regime permitted too much discriminatory conduct by transmission owners in favor of their own sales functions. It also recognized the difficulty in policing the manipulation of capacity and reliability postings on the OASIS, violations of the Standards of Conduct (superior affiliate treatments), and discriminatory application of congestion management procedures.

FERC considered the best solution would be the establishment of Regional Transmission Organizations (RTOs) acting as "big picture" independent grid operators, and able to manage both the reliability and competition needs of regional markets. The Department of Energy re-delegated to FERC the authority (under Section 202(a) of the Federal Power Act) to divide the country into "regional districts for the voluntary interconnection and coordination of industry facilities", allowing FERC to address the interplay of reliability and economic issues on a more global basis.

On December 20, 1999, the FERC issued Order No. 2000 on Regional Transmission Organizations. In the Order, FERC determined that RTOs could address the operational and reliability issues confronting the industry, and eliminate any residual discrimination in transmission services that would occur when the operation of the transmission system

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<sup>5</sup> FERC determined that six ancillary services must be included in open-access tariffs and that two of these services (scheduling, system control, and dispatch; reactive supply and voltage control from generation sources) must be purchased by transmission customers, because the transmitting utility is best suited to provide these services.

remains in the control of a vertically integrated utility. FERC also found that RTOs should be able to benefit consumers through lower electricity rates resulting from a wider choice of services and service providers. Order 2000 also discussed the use of Performance-Based Regulation (PBR) for setting rates and efficiency incentives for transmission companies.

The thrust of Order No. 2000 has further and ongoing importance as its characteristics and functions remained the bases for FERC's later initiatives on Standard Market Design and the Wholesale Power Market Platform. Order 2000, established that, as a minimum, RTOs must have the following four characteristics:

- (1) independence from market participants (no financial interest);
- (2) appropriate scope and regional configuration;
- (3) operational authority for all transmission facilities under its control; and
- (4) exclusive authority to maintain short-term reliability.

Order No. 2000 also defined the eight minimum functions that RTOs must perform:

- (1) administer its own tariff (without multiple access charges) and employ a transmission pricing system that will promote efficient use and expansion of transmission and generation facilities;
- (2) create market mechanisms to manage transmission congestion;
- (3) develop and implement procedures to address parallel path flow issues;
- (4) serve as a provider (though not supplier) of last resort for all ancillary services required in Commission Order No. 888 and subsequent orders;
- (5) operate a single OASIS [open access same-time information system] site for all transmission facilities under its control with responsibility for independently calculating total transmission capability and available transmission capability;
- (6) monitor markets to identify level of service, design flaws and market power;
- (7) plan and coordinate necessary transmission additions and upgrades; and
- (8) ensure the integration of reliability practices within an interconnection and ensure the integration of market interface practices among regions.

Order No. 2000 adopted a voluntary approach to RTO formation and proposed that all public utilities participate in an RTO be operational by December 15, 2001, with congestion management functioning by December 15, 2002 and all aspects in place by December 15, 2004. FERC encouraged RTOs to waive access charges on a reciprocal basis for transactions that cross RTO borders in order to increase the size of the trading areas, and it expected public power entities to participate in the formation of RTOs.

FERC concluded that, when a public utility is engaging in unjust, unreasonable, unduly discriminatory or anti-competitive practices, and when participation in an RTO is a reasonable remedy for such behavior, it had sufficient authority under the Federal Power Act to order the public utility to participate in an RTO.

### **Standard Market Design**

On July 31, 2002, FERC issued its Notice of Proposed Rulemaking (NOPR) on Standard Market Design (SMD). A principal objective of the SMD initiative was to prevent the continuation of unfair business practices. FERC recognized the need for change due to inefficiencies of grid operations, reliability concerns and raised customer costs resulting from under investment in transmission, generation siting far from customers, unduly discriminatory behavior by transmission providers against independent generators and fundamental design flaws in certain existing electricity markets.

The key elements as proposed by FERC's Standard Market Design NOPR of July 2002 were:

- To establish a single flexible transmission service (Network Access Service) with a single open access transmission tariff that applies to all transmission customers (wholesale, unbundled retail and bundled retail) as well as standard market design for wholesale electric markets.
- To require transmission to be operated by an independent entity.
- To adopt locational marginal pricing (LMP)<sup>6</sup>, a market-based method for congestion management and provide tradable financial rights (Congestion Revenue Rights) as a means to lock in a fixed price for transmission.
- Establish procedures to monitor and mitigate market power.
- Establish procedures to assure, on a long-term regional basis, that there are adequate transmission, generation and demand-side resources.
- Establish an access charge to recover embedded transmission costs that would be a demand charge billed on a customer's load ratio share of the transmission provider's cost, and would be paid by any entity taking power off the grid.
- Establish a preference for the auction of Congestion Revenue Rights, but initially allow regional flexibility for a four-year transition period in determining whether to allocate Congestion Revenue Rights to existing customers or auction such rights with all auction revenues going back to customers paying an access charge.
- Require public utilities that operate imbalance energy markets and transmission systems to be independent of market participants.
- Permit customers under existing contracts, including bundled retail customers, to receive the same level and quality of service under standard market design that they receive under their current contracts, to the greatest extent feasible.
- Facilitate real-time and day-ahead markets.
- Adopt a new transmission pricing policy.
- Provide for fair treatment of transmission capacity reserved for reliability.
- Create a formal role for state representatives to participate in the decision-making process of regional transmission organizations or other regional security and reliability entities.<sup>7</sup>
- To more explicitly state, in the pro forma tariff, the obligations of transmission providers to comply with all appropriate standards for ensuring system security and reliability.<sup>8</sup>

Many of the requirements proposed by FERC were later "softened" or eliminated following an extensive consultation process with stakeholders following release of the SMD NOPR.. Elements in the original proposal that did not change were:

- The requirement for public utilities that operate imbalance energy markets and transmission systems to be independent of market participants;
- Facilitation of real-time and day-ahead markets; and
- Creation a formal role for state representatives to participate in the decision-making process of regional transmission organizations or other regional security and reliability entities.

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<sup>6</sup> For summary of Locational Marginal Pricing for congestion management see: "Congestion Management Under Standard Market Design", ISO New England Inc., January 17, 2003, (Pages 5-7) [http://www.iso-ne.com/special\\_studies/Congestion\\_Management\\_Under\\_SMD/2003\\_ISO\\_New\\_England\\_Paper\\_-\\_Congestion\\_Management\\_Under\\_SMD.PDF](http://www.iso-ne.com/special_studies/Congestion_Management_Under_SMD/2003_ISO_New_England_Paper_-_Congestion_Management_Under_SMD.PDF)

<sup>7</sup> FERC proposed that Regional State Advisory Committees would be established to provide guidance and advice to each RTO (or independent transmission operator) relating to planning and expansion issues.

<sup>8</sup> FERC proposed to require compliance with developing North American Electric Reliability Council (NERC) standards on system security.

## Wholesale Power Market Platform

Following nine months of discussion and feedback, FERC modified its Standard Market Design concept and on April 28, 2003, issued a White Paper presenting its updated vision called the Wholesale Power Market Platform.

FERC eliminated several aspects of the SMD where market participants had expressed major concern, including the requirement that public utilities join an Independent Transmission Provider, requirement for a single tariff for all load (wholesale and retail), and assertion of jurisdiction over the transmission component of bundled<sup>9</sup> retail rates. FERC also indicated that it would permit phased-in implementation to better take regional differences into account. While it appears that regional state committees and RTOs/ISOs<sup>10</sup> will have more say, FERC has included significant backstop provisions to settle disputes and/or set rules in cases where issues cannot or are not properly settled at the regional level.

It is anticipated that the Wholesale Power Market Platform will soon move from a work in progress to a set of rules that will appear in FERC's final order, and is expected to become the umbrella under which transmission access will be defined for many years to come.

Major elements of the Wholesale Power Market Platform are as follows: (Numbers do not denote priority.)

1. Public utilities will be required to join an RTO or an ISO, which would be the sole provider of transmission services.
2. Phased-in implementation will be allowed to satisfy the requirements of each region.
3. The non-price terms and conditions of the RTO/ISO tariff will apply equally to all users on a *not unduly discriminatory* basis with appropriate protection of native load customers. FERC will not assert jurisdiction over the rate component of bundled retail services, nor will its jurisdiction over non-price terms of bundled load affect state authority over retail choice decisions, transmission siting or local issues.
4. FERC will look to regional state committees to determine how Transmission Rights should be allocated to current customers based on current use of the grid.
5. In setting the wholesale rate for transmission, FERC will rely upon the transmission rate set by the states for bundled retail service.
6. Each tariff must outline a clear cost recovery policy for transmission investments.
7. Each RTO/ISO must use a real-time market for energy to resolve imbalances; must introduce a day-ahead market designed to work with the congestion management system and a market for ancillary services when the market so requires, and when it is cost efficient to do so.
8. Regions are required to develop a congestion management approach that protects against manipulation, uses the grid efficiently, and promotes the use of lowest cost generation.
9. The approach to and level of resource adequacy (i.e. reserves) will be decided by the states and agreed within the regional committees. Resource adequacy measures must work together with the region's market power mitigation measures to ensure appropriate incentives to invest in sufficient infrastructure.

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<sup>9</sup> The term "bundled" refers to rates that are billed to a customer as a single charge, but which include charges for generation, transmission (and perhaps distribution).

<sup>10</sup> The term RTO/ISO and RTOs/ISOs is used because FERC's proposed rules will not require existing Independent System Operators (ISOs) that are working well to become part of an RTO. Thus, both RTOs and ISOs will exist under FERC's vision of a Wholesale Power Market Platform.

10. RTOs/ISOs will be expected to have a regional planning process in place as soon as practicable. They are to develop periodic regional transmission plans for submission to relevant state and local siting authorities, produce technical assessments of the regional grid and give support to state and regional bodies when requested.
11. Each RTO/ISO will have an independent market monitor that will provide notification to FERC, the regional state committee, and other appropriate regulatory authorities as to the nature of any identified problem and the recommend solution.
12. The tariff must include rules limiting bidding flexibility where there is localized market power and include clear market rules designed to prevent market manipulation strategies.
13. Market mitigation measures must work together with the resource adequacy measures so prices are not suppressed below the level necessary to attract needed infrastructure.
14. FERC has included significant backstop provisions to settle disputes and/or set rules in cases where issues cannot be, or are not being, properly settled at the regional level.<sup>11</sup>

### **Recent US Federal Energy Legislation**

A Bill called the “Energy Policy Act of 2003” was passed by the US House of Representatives on April 11, 2003, and a similar but not identical bill (of the same name) was passed by the Senate on July 31, 2003. Items common to both are:

- (1) Repeal of the Public Utility Holding Company Act of 1935.
- (2) Changes to PURPA eliminating mandatory purchase and sale agreements, and requiring utilities to offer customers real-time pricing, time-of-use metering, and net metering to customers with eligible on-site generators that use renewable energy.<sup>12</sup>
- (3) A statutory mechanism for electric reliability standards incorporating Electric Reliability Organizations to establish and enforce reliability standards for the bulk-power system, subject to FERC review.
- (4) FERC is given authority to require unregulated transmission utilities to provide access at comparable rates, terms and conditions as it charges itself.
- (5) Extension of FERC jurisdiction to certain interstate sales of electric energy that violate FERC rules (and in the case of the Senate bill to determine whether a market based rate for the sale of electric energy is just and reasonable and not unduly discriminatory or preferential.)

The House Bill goes beyond the Senate Bill by (1) Setting guidelines for FERC to establish incentive-based transmission rate treatments to promote capital investment in interstate electric transmission facilities. (2) Providing FERC with authority and responsibility to issue rules establishing appropriate level of price transparency. (3) Making it illegal, for any

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<sup>11</sup> This section on the Wholesale Power Market Platform was prepared with reference to a short paper entitled “Summary of FERC Standard Market Design White Paper” from the web site of the Florida Partnership for Affordable Competitive Energy March 13, 2003. Although reworked here to achieve brevity, some of the wording has been retained.

<http://www.keepupthepace.org/news/legislative/FERC%20White%20Paper%20Summary.pdf>

<sup>12</sup> Under Net Metering, a customer is billed the normal tariff amount when receiving energy and credited the normal tariff amount when transferring energy into the grid, without additional standby, capacity, interconnection or other charges. Eligible residential customers must have generation of 10 kW or less fueled by solar, wind or fuel cells. Eligible commercial customers must have generation of less than 500 kW fueled by a renewable energy resource, landfill gas, or a high efficiency system.

person or entities, to knowingly enter into an arrangement to execute a round-trip trade<sup>13</sup> for the purchase or sale of electric energy at wholesale. (4) Extending FERC's jurisdiction to certain interstate sales of electric energy when FERC's rules are violated.

There are advocates on both sides of the legislative changes. The bills differ in some areas and lobbying will continue until a final version of the bill is passed into law.

The National Association of State Utility Consumer Advocates<sup>14</sup>, before the Senate Committee on Energy and Natural Resources (on March 27, 2003 prior to the bill being passed by either chamber) gave testimony opposing any changes that "would significantly alter the existing statutory paradigm for federal and state regulation of electricity". The Association also voiced its opposition to "financial incentives to encourage investment in transmission facilities, beyond the level of return on investors' equity normally sufficient to achieve reliable service and just and reasonable rates", (Which appears in Section 215 of the House bill). It also lobbied that removal of the "FERC merger review authority, and ...repeal the Public Utility Holding Company Act of 1935 (PUHCA) ...would not be in the overall interests of utility consumers."

The Public Citizen, a Washington-based lobby-group, also voices strong opposition to the repeal of the PUHCA. It is surprising that both the House and Senate versions of the bill would have been passed with this included.

### **FERC's Roadmap for State and Regional Participation in SMD**

The Chairman of FERC, before the Senate Committee on Energy and Natural Resources, March 27, 2003, outlined a formal process whereby states representatives will participate in the decision-making of regional transmission organizations and other regional entities. The process was described as follows:

- States would be authorized to enter into agreements to establish 'Regional Energy Service Commissions (RESC), composed of one member from each State appointed by the governor as provided by state law. (Section 216(k) of the House bill.)
- A RESC could be vested with jurisdiction over:
  - (a) transmission planning and siting
  - (b) interconnection of generation facilities to the interstate transmission grid
  - (c) rate design and revenue requirements for transmission and wholesale sales
  - (d) incentive rates for transmission
  - (e) market power review and market monitoring
  - (f) formation and approval of 'Transmission Organizations,' reliability standards and rules, and adequate enforcement mechanisms.

Mr. Wood noted complexities in establishing RESCs, and concern with certain aspects including delays that could result in establishing the committees. Although this "roadmap" is not specifically included legislation, it represents a generic vision for state involvement.

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<sup>13</sup> A round trip trade involves an offsetting purchase and sale without financial gain or loss undertaken with the specific intent to distort reported revenues, trading volumes or prices.

<sup>14</sup> An Association that represents 42 states and the District of Columbia.

## Part 2

### Transmission Rights

#### Overview

A transmission right assigns priority when there is congestion<sup>15</sup> on the transmission network, and the holder of such rights normally does not pay additional fees when there is congestion costs. A transmission right enables Load Serving Entities (LSEs) to guarantee continuous supply to their customers regardless of the level of transmission congestion, and is a necessary tool in order for markets to operate in a dependable way.

FERC presented views on Transmission Rights in a “Working Paper” dated March 15, 2002, and in an “Options Paper” Dated April 10, 2002. Recently, it presented additional views in its White Paper on the Wholesale Power Market Platform dated April 28, 2003 (as well as in the Appendix to that paper and in a staff discussion document). FERC’s views along with the views of several parties that have subsequently made comments are summarized below.

#### FERC’s Proposals

In its Working Paper FERC acknowledges that the lack of a single set of rules governing the transmission of electric energy, resulted in market design flaws that lead to operational problems and unclear price signals to attract appropriate generation and transmission investment. It proposed that existing the three part tariff be replaced by a single Network Access Service tariff, and identified the transition issues that needed to be resolved in moving to one tariff for all services to be:

- 1) the manner in which embedded costs of the transmission system will be recovered;
- 2) the manner in which Transmission Rights will be allocated among customers; and
- 3) transition of customers under existing contracts (real or implicit) to the new service.

It proposed that Network Access Service could be purchased by load serving entities as well as non-load serving entities to move power between two points, a source and a sink<sup>16</sup>, and that a Network Access Service customer would have access to all sources and sinks on the system. Under the Network Access Service there would be two types of transmission related rights. An Access Right (the right to move power between any two points on the system), and the Transmission Right (the right to a predetermined price for service between two specific points on the system). An access charge would be used to recover the embedded costs of the system.

To prompt discussion, FERC asked several questions regarding the design of the proposed transmission Network Access Tariffs. The issues posed by FERC along with the views of interested parties making comment are set out below:<sup>17</sup>

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<sup>15</sup> When there is more electricity load required at a location than there is transmission capacity across a section of a transmission grid, normally requiring that a portion of the load be acquired elsewhere at a higher cost.

<sup>16</sup> A source is defined here as the location where a transaction originates, and a sink is defined as the location where a transaction terminates.

<sup>17</sup> The views of interested parties should be considered a “representative” sample and not an exhaustive sample. This section attempts to convey the essence of the views of the following entities: Ontario IMO, PJM Interconnection, the Transmission Access Policy Study Group (TAPS), and the CREPC Transmission Pricing Work Group. For more detail on their views see Part 2 of the Literature Review. As time went on, and FERC moved from its Standard Market Design NOPR to the “Working Paper”, the “Options Paper” and later to the “White Paper”, common themes emerged in the parties’ views and there became an apparent convergence of views on many issues.

***Who pays the access charge for deliveries within the transmission provider's system?***

Parties agreed that only customers that take power off the grid should pay access charges.

***Should the access charge apply to exports and wheel-throughs?***

Opinions varied. There was some consensus to begin with a lower (at least incremental cost) recovery of access charges. Ontario thought elimination of the charges would lead to reciprocal treatment by neighboring jurisdictions, while some TAPS<sup>18</sup> members supported full recovery.

***Should the access charge be billed based on peak load or total usage?***

There was consensus for continuation of the monthly peak load billing methodology

***Transition of Customers under Existing Wholesale Contracts and Bundled Retail Customers Load to Transmission Service under the Revised Pro Forma Tariff***

There was a consensus that all services (bundled retail and wholesale load as well as unbundled retail service and wholesale service) should be placed under the same tariff.

***Allocation of Transmission Rights:***

***Should Historical Customers get the Initial Transmission Rights?***

TAPS views “the initial allocation of Transmission Rights among customers is primarily a question of equity, not efficiency. Basic fairness requires that historical customers receive the initial Transmission Rights, and that those rights be allocated by assignment not auction”. TAPS contends that this “approach is essential to preventing an unfair burden on customers who have long supported the transmission grid and who have properly supported their resource planning and generation investments with long-term firm transmission reservations...”. Consensus is for auction after initial allocation.

***If existing customers are given the initial conversion rights, how should Transmission Rights be allocated? ...***

TAPS Supports assignment of initial Transmission Rights based on existing contract rights and historical usage. Ontario favors auction of Transmission Rights and assigning the auction revenues that are in excess of congestion payouts to the transmission customers as credits to reduce the embedded charges.

**Allocation of Transmission Rights**

FERC’s Options Paper, under the heading “If existing customers are given the initial conversion rights, how should Transmission Rights be allocated”, listed as Option 1:

“Assign rights based on existing contract rights and historical usage. The Commission could assign the Transmission Rights based on existing sources and sinks in Point-to-Point contracts and the designated resources for Network Integration Service and bundled retail load. *In essence, those customers that currently are using those points for firm service would get the right to continue to use those points without paying for congestion. ...*

This approach comes closest to replicating the rights customers currently have under existing contracts or for bundled retail load. However, under this methodology it may be difficult for new entrants to acquire Transmission Rights.”<sup>19</sup> (Emphasis added.)

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<sup>18</sup> Transmission Access Policy Study Group. Association of transmission dependent utilities from thirty states.

<sup>19</sup> FERC Options Paper – April 10, 2002 - Options for Resolving Rate and Transition Issues in Standardized Transmission Service and Wholesale Electric Market Design  
[http://www.westgov.org/wieb/meetings/crepcsprg2002/briefing%20materials/options\\_paper.htm#transrights](http://www.westgov.org/wieb/meetings/crepcsprg2002/briefing%20materials/options_paper.htm#transrights)

FERC's White Paper stated the following:

*“As with our earlier restructuring efforts in the natural gas and electric power industries, we want to ensure that existing customers retain their existing transmission rights and retain rights for future load growth. ...*

*In the Final Rule, for RTOs or ISOs that have not already addressed this issue, these rights would be allocated according to existing contracts and existing service arrangements in order to hold customers harmless. To the extent transmission rights have already been approved by the Commission in RTO or ISO orders we would not override these decisions in the Final Rule.”<sup>20</sup> (Emphasis added.)*

TAPS has repeatedly urged provision for long term Fixed Transmission Rights (FTRs’):

*“Nor should there be any confusion as to the length of the commitment to preserve existing transmission rights. FTRs must be assigned to each LSE, up to the LSE’s peak load, for the full amount and term of the existing transmission rights and associated resource. A 20-year FTR — much less a one- or five-year FTR that the NOPR seems to contemplate (P 249) — is no substitute for the 35-year firm transmission right on which an LSE financed a base load coal plant.”<sup>21</sup>*

In response to FERC's Options Paper, TAPS stated “TAPS Supports assignment of initial Transmission Rights based on existing contract rights and historical usage”. The theme of placing historical usage at the same level of importance as contracts is recurring. In the literature reviewed, it appears that assignment of transmission rights was discussed at the level of LSEs (i.e. wholesale customers) and not to the level of individual retail customers, regardless of their size.

Views on historical usage are relevant in any jurisdiction including Prince Edward Island. It becomes increasingly important as the cable link with New Brunswick experiences longer periods of congestion. There are two Load Serving Entities on Prince Edward Island, Maritime Electric and the City of Summerside. Historical transmission usage by these LSEs applies to both the cable link from New Brunswick and other transmission facilities on the Island. Although the City of Summerside may have been executing the majority of such usage indirectly through bundled tariffs for electricity purchased from Maritime Electric for resale to its customers, it all represents the “historical usage” of Summerside as an LSE. Customers in Summerside have been paying (within their rates) a portion of both fixed and variable costs associated with all transmission facilities used by Maritime Electric to serve Summerside.

To ensure fairness in the allocation of and charges for transmission usage on PEI, tariff design must be based on rationale as thorough and as robust as would be the case if PEI offered fully open transmission access. This includes assumptions relating to implications of transmission rights to the extent necessary to establish fair rates.

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<sup>20</sup> FERC Wholesale Power Market Design Platform – White Paper – April 28, 2003. (pages 5 & 10)  
[http://www.ferc.gov/industries/electric/indus-act/smd/white\\_paper.pdf](http://www.ferc.gov/industries/electric/indus-act/smd/white_paper.pdf)

<sup>21</sup> TAPS COMMENTS ON FERC WHITE PAPER: FTR ISSUES – August 6, 2003  
<http://www.tapsgroup.org/030806%20FTR%20Issues.pdf>

## PART 3

### Cost Allocation Principles - Open Access Transmission Tariff

On June 19, 2003, the New Brunswick Board of Commissioners of Public Utilities (PUB) approved an Open Access Transmission Tariff (OATT) for NB Power. It had an effective date of September 30, 2003, at which time electricity supplier choice was made available for municipal wholesale and industrial customers served from NB Power's transmission system (69 kV and above). The rate making principles underlying the NB Power OATT provide a very recent example of how FERC guidelines are followed by most jurisdictions in North America in setting transmission tariffs.

“Although the FERC has no direct jurisdiction outside the United States, it has had significant influence on the implementation and design of external tariffs. First, the FERC has instituted a reciprocity requirement on all non-jurisdictional utilities that use the tariffs of jurisdictional utilities. Second, non-jurisdictional companies wishing to sell electric power at market based prices in the U.S. must acquire a power marketing authority license from the FERC. Thirdly, the license requires that the reciprocal transmission access to be provided is done under a tariff that is equal to or superior to the Pro Forma. The effect of this latter point has led to the development and implementation of Pro Forma tariffs by utilities in Canada and Mexico. Today the Order 888 Pro Forma Tariff is the most commonly applied tariff in Canada as well as the United States.”<sup>22</sup>

“While the FERC has no jurisdiction in New Brunswick, its principles have influenced policy makers here. The New Brunswick Market Design Committee [MDC] has reviewed transmission tariff issues as part of its work regarding the implementation of supplier choice in New Brunswick. ...

*The MDC recommends that the transmission system will provide open, equal non-discriminatory access to all eligible market participants under terms and conditions compatible with FERC Orders 888 and 889. The System Operator will have an Open Access Transmission (OATT) for network and point-to-point service covering transmission service: within the province, into the province, out of the province, and through the province. The PUB shall approve the OATT.”<sup>23</sup>*

These references are intended to underscore how the information contained in the first section of this report has affected, and has been taken into account by, the Province of New Brunswick during 2003 in the development of its Open Access Transmission Tariff. Therefore, the rate-making principles underlying New Brunswick's OATT comply with FERC policies and may be considered as a good generic model.

FERC's Transmission Pricing Policy Statement issued on October 26, 1994 specified five principles regarding the pricing of transmission services. Transmission Pricing: (1) Must meet the traditional revenue requirement. (2) Must reflect comparability. (3) Should promote economic efficiency. (4) Should Promote Fairness, and (5) Should be practical.

In 1996 the FERC issued Order 888 which, included the *Pro Forma Tariff*. The order required all utilities under FERC jurisdiction to file a tariff specifying the terms, conditions and a pricing methodology that conformed to the pricing principles. At the same time, Order 889 required utilities to utilize an Open Access Same-Time Information System (OASIS) and Standards of Conduct with respect to non-discriminatory control of third party information.

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<sup>22</sup> “NB Power Transmission Tariff Design. June 2002” Section 2.3.5 Appendix “B” to Direct Evidence of George Porter of NB Power Application for Open Access Transmission Tariff dated June 21, 2002  
[http://www.nbpower.com/en/about/trans\\_dist/tar/appendixb-tar.pdf](http://www.nbpower.com/en/about/trans_dist/tar/appendixb-tar.pdf)

<sup>23</sup> “NB Power Transmission Tariff Design. June 2002” Sections 2.1 and 2.4.1

(This reference provides the basis for all nearly all the information contained in Part 3.)

## Steps in the Rate Design Process

The steps in the rate design process are: (1) Establishment of the Revenue Requirement. (2) Allocation of Revenue Requirement. (3) Recovery of costs from each customer class.

### Revenue Requirement

The revenue requirement relates to all lines at voltages of 69 kV or higher and terminal stations between transmission lines and includes amortization costs, operation, maintenance and administration (OM&A) costs, finance charges, payments in lieu of taxes, plus a regulated return on investment. In addition, it includes a portion of the costs associated with the generation step up transformers. OM&A is allocated to each asset based on gross asset value while interest, taxes and return are allocated based on net asset value.

### Cost Allocation Analysis

The purpose of the cost allocation analysis, is to allocate the appropriate revenue requirement to the appropriate services. It requires the following steps:

- (a) Definition of the transmission services to be provided
- (b) Definition of the basic functions of the transmission system
- (c) Allocation of revenue requirements to the different functional uses of the system
- (d) Determination of system usage by service
- (e) Allocation of the functional costs to the transmission services
  - (a) Services to be defined in the NB OATT are Point to Point and Network Service which are consistent with the FERC *Pro Forma Tariff*; in addition, the Ancillary Services of Scheduling, System Control, and must be provided by NB Power.

Point-to-Point Service refers to the reservation of capacity for the transmission of energy from a Point of Receipt to a Point of Delivery. This service is most often used for wholesale transactions between systems.

Network Service is firm transmission service for the delivery of both capacity and energy to the high side of the substation transformer of the transmission customer. It is usually used for supply of load within the system.

Scheduling, System Control, and Dispatch Service is required to schedule the movement of power into, out of, through, or within a control area. Only the system operator of the control area in which the transmission facilities are located can provide this service.
  - (b) For the NB Power Tariff, assets are grouped into four main functional groups:
    - Generation Related Transmission Assets (GRTAs)
    - Bulk Network Assets (Interconnections and In-Province network)
    - Local Service Assets
    - Energy Control Center Assets
  - (c) Functional Costs for the NB Power Tariff allocated as follows:
    - All GRTAs allocated as direct assignment charges to generators.
    - Interconnections, In-province Bulk Network and Local Service costs are the common use portion of the transmission system and are allocated as revenue requirement costs to be collected from transmission services under the tariff.<sup>24</sup>
    - Energy Control Center costs are allocated to Scheduling, System Control and Dispatch and are to be collected through tariff rates for that service.

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<sup>24</sup> Interconnections and local service lines to be included with the bulk network because they have relatively low costs and they provide market opportunities to both loads and suppliers.

- (d) Use of 12 monthly coincident peaks is considered a fair measure upon which to allocate the revenue requirement of the transmission system that balances the “cost causation” and “used and useful” principles of transmission tariff rate making.
- (e) The revenue requirement is allocated to the different transmission services based on their load ratio share of the system.

### **Rate Design**

The design of rates involves the following:

- (a) Selection of a rate structure
- (b) Selection of billing determinants for each service
- (c) Determination of rates using the billing determinants to collect the revenue requirements
  - (a) NB Power’s current approach is a postage stamp rate (the structure applied in the FERC Order 888 Pro Forma Tariff). This has been adopted by many U.S. jurisdictions, and by Saskatchewan, Manitoba, and Quebec. British Columbia, Alberta and Ontario have opted for zonal rate approaches.
  - (b) Commonly used billing determinants are customer charge, kW of demand, and kWh of energy. In the case of long-term point-to-point customers, the reserved MWs define the committed capacity so reserved quantity can readily be used. For network customers it is a function of the 12 monthly coincident peak loads. FERC Order 888 and subsequent jurisprudence clearly state that self-generating customers must be provided with the option to choose between point-to-point service and network service. In the *FERC Pro Forma*, if the customer chooses network service the billing determinant is the load ratio share based on the gross demand at the time of system peak, not the net demand. However, based on work done in New Brunswick by the MDC pursuant to the *Energy Policy White Paper*, net non-coincident demand by delivery point has been chosen as the billing determinant for network service reserved capacity for point-to-point service.
  - (c) Given that the revenue requirement and billing determinants have been defined for each service the nominal rate is merely the revenue requirement for the service divided by the respective billing determinant. Appalachian pricing will also be applied whereby shorter term services priced higher for an equivalent time period during on-peak with daily rate being 1/5<sup>th</sup> of the weekly rate, and the hourly rate 1/16<sup>th</sup> of the daily rate. A power factor penalty is also applied.

### **Summary**

By applying the principles established by FERC for compliance with its Open Access Transmission Tariff, NB Power has followed guidelines similar to the test for “just and reasonable” and “fair and equitable” rates as described in the text “Principles of Public Utility Rates” by Bonbright, Danielsen and Kamerschen. This demonstrates that rate design for FERC compliance introduces little additional work beyond what has been traditionally been required for good rate design.

## **PART 4**

### **Jurisdiction Specific Information**

#### **New England, Canada and the Maritimes**

##### **The New England States**

The New England States appear to lead the continent in terms of having an advanced market design, that most similarly follows what FERC might consider (left to its own discretion) to be solidly based on appropriate theories for encouraging the most efficient long-term market behavior. This statement is not intended to take away from the well operating models of PJM (Pennsylvania, New Jersey, Maryland) or New York, but rather to underscore the theoretical alignment of New England with FERC.

The New England Conference of Public Utilities Commissioners, Inc., in a letter to the Chairman of FERC, dated March 26, 2003, applauded FERC's efforts in working towards a standard market design, and suggested that New England's successes in applying regional sensitivities to national initiatives should be replicated elsewhere.

It noted that on March 1, 2003, New England implemented a new market design that includes the most important features of the Commission's proposed SMD, including a congestion management system based on locational marginal pricing, and a multi-settlement system. This new market design builds on the long commitment of the New England region to a coordinated power pool, non-discriminatory access to the transmission grid, and the reduction of seams between regions.

It also requested that the Commission adopt the following general recommendations and discuss them in the upcoming "White Paper."

- Acknowledge that regional differences warrant regional approaches for some aspects of market design... and realize that on many issues federal involvement may only be necessary when agreement cannot be reached at the regional level.
- Acknowledge that many aspects of resource adequacy, transmission planning, and siting are regional and state jurisdictional issues, and should be dealt with in these forums...

The New England States, with the exception of Vermont, have both wholesale and retail competition, and all customers may access the transmission system in order to acquire power from elsewhere. In Vermont, where there has not been electricity restructuring, FERC's jurisdiction still applies for transmission access at the wholesale level, and municipal utilities are eligible to purchase power elsewhere and take delivery under the Open Access Transmission Tariff structure, (though retail customers are not eligible for open transmission access).

##### **Canadian Compliance with FERC and Transmission Access Rules**

Canadian electric utilities understand both the complexity and the fragility of the North American power grid, as well as their interdependence with electric utilities in the United States. The Canadian utilities are fully aware that any improvements in the market rules that can be instituted now are vital to the stability and reliability of the grid and will help buy the time needed to construct new transmission facilities.

While at the national level concerns of sovereignty are voiced, at the provincial level there is an anxiousness to be able to participate in export markets. British Columbia has found it advantages to participate in the formation of market rules, and willingly follows criteria set out by FERC. While Ontario, during its restructuring process has established an Independent

Market Operator, it has set up its rules in a way that are compatible with FERC. All of the other provinces that export electricity to the U.S. meet at least the minimum FERC requirements for reciprocity.

### **New Brunswick**

As of Sept 30, 2003, its 3 municipal electric utilities (Saint John, Edmundston and Perth-Andover) and its large industrial customers have access to the transmission system of NB Power, and have the ability to purchase their electricity from any supplier of their choosing. Likewise, any power producer in New Brunswick located near the NB Power transmission system, have nondiscriminatory access to the network and can sell their electricity to any customer on the grid. They can export into the United States provided that they hold a power marketing authority license issued by FERC. With regard to generators that might locate in an area served at distribution voltage, the New Brunswick Market Design Committee recommended that the producer receive a price equal to the utility's avoided cost, along with savings in line losses to the point of sale. It is expected that this recommendation will be included in the Market Rules being developed.

Details of the approach taken by New Brunswick is contained in Part 3 of this report, which outlines the Open Access Transmission Tariff approved by the New Brunswick PUB.

### **Nova Scotia**

Nova Scotia initially indicated a willingness to participate in the New England (Northeast) RTO. However, the final report of the Nova Scotia Electricity Marketplace Governance Committee (EMGC), released in October 2003, indicates a preference to allow open access only to the six municipal utilities (Antigonish, Berwick, Canso, Lunenburg, Mahone Bay and Riverport). These six utilities represent approximately 2% of the province's load. The EMGC proposes not to include large industrial customers at this time. It also proposes to initially use a transmission tariff that would fall short of FERC's Order 889 requirement for an internet based open access real-time information system, although it recognizes the potential need to later migrate to full FERC compliance.

Recommendations of the EGMC final report include the following:

#### Price Unbundling

It recommended that Nova Scotia Power Inc. (NSPI) develop and file a transmission tariff that would ensure open and non-discriminatory transmission access for all market participants. The tariff should be developed in an evolutionary manner and initially include a scheduling and information system that need not be an open access same-time information system (OASIS) as defined by FERC in Order 889. The tariff could eventually evolve toward FERC compatibility, and at such time it is determined an OASIS is required, ways to minimize cost should be considered including the purchase of OASIS service from another jurisdiction.

#### Services Offered

It recommended that the tariff should provide for Network Integration Service for the delivery of both capacity and energy for the supply of load located within the Nova Scotia Control area, and Point-to-Point service for the reservation of transmission capacity for imports into and exports from Nova Scotia. Ancillary services offered by the system operator and included in the transmission tariff should include: (1) scheduling, control and dispatch, (2) reactive supply and voltage control (3) energy imbalance service based on costs, (4) regulation and frequency response service, (5) operating reserve – spinning reserve, and (6) operating reserve – supplemental.

### Tariff Design

It recommended that customers should pay for transmission services on the basis of cost causation, with demand charges allocated based on the average twelve monthly coincident peaks<sup>25</sup>. It is recommended that the billing determinants be *monthly non-coincident peak*, for network customers, *reserved capacity* for point-to-point customers and *hourly net non-coincident peak* for self-generation customers. The EMGC recommended a consistent charge regardless of location (i.e. a postage stamp rate).

### Congestion Costs and Transmission Rights

It recommended that existing customers share the congestion costs on the existing system while new generation and new loads would pay for incremental congestion caused by such additions. Consistent with the FERC pro forma tariff, existing firm load customers within Nova Scotia should be entitled to firm network service and have renewal rights to such service, and Nova Scotia should maintain a system of import and export transmission rights for electricity and capacity.

### System Operator Functions and Metering

It recommended that NSPI be given the role and responsibilities of a transmission provider. And it recommended that as meters are replaced or resealed at transmission interfaces with generation, distribution or large customers, that they should be upgraded to revenue quality interval meters.

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<sup>25</sup> *Coincident Peak* is the amount of metered demand of the customer (load) at the time of system peak.

*Non-Coincident Peak* is the maximum metered demand of the customer (load), without reference to the system peak. Tariffs may be based on hourly, monthly or yearly non-coincident peak.

*Net Non-Coincident Peak* is the non-coincident peak less any amount that is provided by self-generation.

# Literature Review

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**New England, Canada and the Maritimes**

## Literature Review – Part 1

### Legislative and Regulatory Framework

#### The Need for Standard Market Design

Pat Wood, III, Chairman of FERC, summarized the need for change as follows:

“The wholesale power market today has many of the worst features of both regulated and competitive markets, and few of the benefits of either. There is continuing discrimination against certain buyers and sellers that harms new market entrants and raises costs to end-use customers; there are extensive loopholes between state and regional rules that allow market manipulation to raise prices and compromise reliability; there is under-investment in transmission that raises energy costs by billions of dollars across the grid and exacerbates reliability problems; and the practically-inelastic demand curve means there is little customer discipline on price and supply.”<sup>26</sup>

“For more than a decade, the wholesale power industry has been stuck in the transition from its heavily-regulated past to a competitively-driven future. The uncertainty of this transition has discouraged investment in transmission and generation infrastructure.”<sup>27</sup>

The existing structure had not succeeded in preventing Unfair Business Practices:

“The commission’s Standard Market Design identifies examples of transmission market power that serve as impediments to competition. The SMD is designed to reform and prevent such practices.

Much of the problem is directly attributable to the continued ability of vertically integrated transmission providers to exercise some degree of market power to advantage its own or affiliated generation. The SMD expands upon Order 200’s encouragement that all transmission facilities be operated independently, whether by a Regional Transmission Organization or an independent transmission operator under contract.”<sup>28</sup>

Examples of anti-competitive practices by vertically integrated transmission providers include: (1) Recall of capacity to serve native load. (2) Delays in granting requested service. (3) Scheduling advantages. (4) Benefiting by proprietary access to calculations of available transfer capacity and prohibited [off OASIS] communications between transmission and generation affiliates. (5) Reserving more transmission system capacity than required for native load thus causing shortages and increased costs to competing suppliers, and (6) Manipulate transmission loading relief procedures to favor their own deals. Furthermore, power traders such as Enron) were able to exploit the existing congestion management rules to their own benefit, at the expense of others.

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<sup>26</sup> Summary of the Testimony of Pat Wood, III, Chairman of FERC Before the Committee on Energy and Natural Resources, United States Senate, September 17, 2002

<http://www.ferc.gov/press-room/ct-archives/2002/09-17-02-wood.pdf>

<sup>27</sup> Testimony of Pat Wood, III, Chairman of FERC Before the Committee on Energy and Natural Resources, United States Senate, March 27, 2003

<http://www.ferc.gov/press-room/ct-current/03-27-03-wood.pdf>

<sup>28</sup> FERC News Release on Standard Market Design, July 31, 2002

<http://www.ferc.gov/press-room/pr-archives/2002/2002-3/smdx.pdf>

## Process for Developing the Standard Market Design

To address these concerns, FERC undertook an extensive consultation process with stakeholders and academics prior to its release of the July 31, 2002, SMD NOPER.

“Following the most intensive public outreach in Commission history, on July 31, the Commission issued a proposed rule addressing many of the crucial details needed to be resolved in order to capture the benefits of competitive wholesale power markets for customers. Every aspect of the rule is open to comment and we particularly invite comment on over 70 specific issues. The proposal followed from ten months of specific workshops, technical conferences, hearings and targeted outreach both in Washington and across the country. What we have heard and learned was publicly disseminated well in advance of the rule through Commission documents and our web site, and we have received virtually continuous feedback from all quarters on the various issues. Our July 31 proposal represents the broad consensus reached through the process in addition to our “cuts” on a handful of non-consensus issues. Although the proposed rule represents our best judgment given the information available, our minds remain open to new views, information and ideas.

Since we issued the proposed rule, we have been actively meeting with groups and individuals across the country to help them understand the proposal and understand their concerns. To date, FERC staff and commissioners have given over two dozen presentations to groups of state regulators, public officials and conference attendees and discussed the proposal in every press call and speech. At this time, we have another 30 outreach presentations scheduled to interest groups, trade associations, conferences, and others. Appendix B<sup>29</sup> lists many of the activities and meetings we conducted in developing the proposal, and many of the formal outreach meetings scheduled since the July 31 issuance of the proposed rule.

...These efforts will assure that everyone with a stake in this rulemaking has a further chance to be heard with the goal being a fully fleshed out set of practical market rules.”<sup>30</sup>

### **Pre SMD NOPR Submissions**

On April 10, 2002, FERC issued an paper entitled “Options for Resolving Rate and Transmission Issues in Standardized Transmission Service and Wholesale Electric Market Design (“Options Paper”). On May 2, 2002 the Transmission Access Policy Study Group (“TAPS”) provided comments to FERC on the Options Paper. TAPS is an informal association of transmission-dependent utilities in more than 30 states, promoting open and non-discriminatory transmission in many forums since formed in 1989.

Some of the major points of the TAPS comments are contained in the following excerpts:

“The Commission is attempting to grapple, on a very fast track, with questions for which there are no easy answers, but which are critical to the success of the Commission’s standard market design (“SMD”) initiative. As transmission dependent utilities that have long pressed for competitive markets, we see the benefits of the vibrant LMP-based short-term markets the Commission is seeking to put in place. However, it is also essential that the market design provide, on a forward-looking basis, firm transmission with the price certainty needed to

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<sup>29</sup> Appendix B to Sept. 17, 2002 Testimony of Pat Wood, III, Chairman of FERC Before the Committee on Energy and Natural Resources, U.S. Senate. List of Approximately 100 Meetings, Workshops and Conferences.

<http://www.ferc.gov/press-room/ct-archives/2002/09-17-02-wood-b.pdf>

<sup>30</sup> Testimony of Pat Wood, III, Chairman of FERC Before the Committee on Energy and Natural Resources, United States Senate, September 17, 2002

<http://www.ferc.gov/press-room/ct-archives/2002/09-17-02-wood.pdf>

- (i) preserve existing and accommodate new long-term resource commitments that hedge short-term price volatility,
- (ii) provide the generation adequacy required for short-term markets to work efficiently, and
- (iii) most fundamentally, enable load serving entities (“LSE”) to meet state and local service obligations.

... the Commission’s initiative can succeed only if designed to:

- honor the existing transmission rights that support the ability of LSEs to serve their loads at stable transmission prices from their existing resources, and
- require the transmission planning and expansion necessary to ensure the transmission adequacy and price stability required to support investment in new generation needed to serve growing loads and to provide reliable service.

The interwoven objectives of transmission and generation adequacy dictate that:

- (1) RTOs must have a clear transmission planning and expansion obligation; and
- (2) network access service must provide a mechanism that assures LSEs the ability to secure long-term transmission at stable prices necessary to support long-term generation investments.

Today, [Open Access Transmission Tariff] OATT network integration service allows an LSE to develop a portfolio of resources that it can economically dispatch to serve its aggregated load with reasonable price certainty and delivery assurance. The key to the process is planning: the transmission provider is required to plan for a network customer’s load; once a network resource designation is accepted for firm service, it is incorporated into the base case for planning the transmission system. LSEs will be discouraged from making the long-term commitments necessary to support new generation (by construction, or purchase from a competitive supplier) if they are at risk of not being able to secure firm transmission delivery of new resources to load with reasonable price certainty on a long-term basis, i.e., if they must repeatedly outbid others for FTRs over the life of the resource.

To achieve the important goals of transmission and generation adequacy, network access service must retain key planning features of network integration service: an obligation to plan for service to aggregated network load from planned designated network resources, and a right to firm service from those resources to aggregated loads without significant exposure to the financial uncertainties associated with congestion costs. In SMD terms, the planning process should be tied to the network resource designation process, which in turn should be tied to the allocation of long-term FTRs.

... Given the objectives of ensuring a robust grid and maintaining the benefits of network integration service, we answer the Commission’s questions as follows:

1. Load (for whom the grid is planned) should bear most of the cost of the grid (based on monthly peak load), but consideration should be given to a rate design that assigns a portion of the embedded cost of the grid to generation (to help deal with the “export generation” issue both intra and inter-RTO). Through charges pose difficult issues requiring the balancing of consideration of cost causation and equity with concerns about the market-constricting impacts of pancaked rates.
2. Bundled retail load should be subject to the same tariff as unbundled retail and wholesale load, while those with grandfathered contracts should be strongly encouraged (but not forced) to convert to the new network access service, by (among other things) modeling that service closely after OATT network integration service.
3. FTRs should be assigned to those with existing firm rights (by virtue of grandfathered agreements or OATT network service agreements and associated network resource

designations, point-to-point reservations, or transmission provider network resource designations), and historical usage.

4. Generation adequacy will be supported by a strong RTO commitment to transmission planning and expansion and the price stability needed to support new generation investment. These requirements can best be achieved by tying assignment of long-term FTRs to network resource designation and the planning process. TAPS supports capacity reserve obligations. However, the appropriate approach to implement such obligations is not clear, and may be subject initially to regional variation, with state input.

... The four issues discussed in the Options Paper – recovery of embedded cost, allocation of transmission rights, transition to the new service, and generation adequacy – are inherently linked... The Commission needs a policy perspective from which to judge the many issues that arise in the SMD process. ...

**- LSEs' existing ability to flexibly and economically serve load from existing resources must be preserved**

TAPS strongly agrees that “Customers under existing contracts (real or implicit) should continue to receive the same level and quality of service under standard market design” (SMD Working Paper at 7) and supports the Commission’s stated “intent ... to preserve the existing rights of current users of the system” (id. at 8). Such preservation is critical to those, like TAPS members, who have fought hard for their transmission rights (e.g., through antitrust cases), and who have invested billions of dollars in generation on the basis of these firm service commitments...

**RTOs must have a clear planning and expansion obligation.**

For SMD to succeed, it must be accompanied by a strong transmission planning obligation, so that the infrastructure needed to support competitive markets and new generation is likely to be built. ... Letting the profit motives of individual market participants control the design, location, and timing of transmission additions will not work. What is needed to get transmission sited and built is a demonstration that proposed expansions are part of a least-cost regional plan that takes into account all regional needs, while making appropriate tradeoffs. ... An open, independent RTO regional planning and expansion process, that includes public and state participation and addresses regional needs as a whole is far more likely to achieve the robust grid that reliability and competitive markets require...

**- Network access service must include a mechanism that ensures stable transmission prices.**

Stability of transmission prices and confidence in the availability of long-term firm service is necessary to support investment in new generation resources needed to provide generation adequacy. The Commission should take care in developing a new service that these elements are preserved. The sheer promise of “access” subject to congestion at an unspecified price will not support the many billions of dollars of generation investment that the nation requires and, more specifically, that LSEs need to meet their continuing service obligations...

### **- Allocation of Transmission Rights**

TAPS agrees with the Options Paper (at 11) that the initial allocation of Transmission Rights among customers is primarily a question of equity, not efficiency. Basic fairness requires that historical customers receive the initial Transmission Rights, and that those rights be allocated by assignment, not auction... TAPS strongly prefers Option 1, which would convert existing customers' usage to initial Transmission Rights. As explained in TAPS' SMD Working Paper Comments (at 20-24), this approach is essential to preventing an unfair burden on customers who have long supported the transmission grid and who have properly supported their resource planning and generation investments with long-term firm transmission reservations pursuant to pre-OATT contracts or network resource designations under the OATT. ... The initial Transmission Rights must be designed to reflect the network nature of the pre-existing service, and to preserve customers' rights...

### **- Long Term Generation Adequacy**

TAPS favors RTO-wide reserve obligations in order to enhance reliability and dampen price spikes. Option 1—depending on energy prices to ensure generation adequacy—will not ensure sufficient reserves. As California shows, the market cannot be depended on “to provide.” Nor is it a question of providing information to individual load serving entities, as the Options Paper suggests (at 13). To have their desired effect, reserve sufficiency requirements must be imposed on all LSEs, because of the temptation of individual market participants to gain a competitive advantage by free riding. No individual LSE, by carrying reasonable reserves itself, can fully insulate itself from the effects of price spikes or rolling blackouts induced by regional shortages. Option 1 is neither politically acceptable nor good policy.

...While there may be room for some regional diversity, certain fundamentals are clear and can be applied to test the appropriateness of proposed reserves regimens:

- The reserve obligation should be placed on all LSEs within an RTO, as a basic requirement of participation in the market.
- The ability of LSEs to meet the assigned reserve obligation must be supported by a planning model that ensures the transmission planning and expansion, and assignment of long-term FTRs for new network resources, needed to support financing and construction of new resources.
- The reserves adequacy mechanism must be demonstrated to provide real benefits. We do not support paper ICAP that serves no purpose other than add costs to LSEs. A designated capacity resource must be available in a meaningful way to those depending on it.<sup>31</sup>

On November 15, 2002, TAPS made another submission to FERC entitled *Overview of TAPS Position and Principles to Guide Consideration and Implementation of SMD*. It contained the following comment, suggesting a vision of the future that is dramatically different than the vision which launched electricity restructuring in the first place.

“An underlying assumption of SMD is a strong merchant power sector that will take the risk of building and selling into day ahead and hourly markets. In many areas, the merchant sector is practically defunct. It is no accident that Exelon, one of the largest incumbent utilities, spoke for the Electric Power Supply Association at a recent Senate oversight hearing on SMD. We believe much less merchant risk will be taken in the future than anticipated even several months ago, and that long-term capacity contracts with load serving entities will be essential for financing new plants. The merchant shake

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<sup>31</sup> Transmission Access Policy Study Group comments to FERC on the SMD Options Paper. May 2, 2002. <http://www.tapsgroup.org/Industry%20Issues.htm>

out is also increasing generation concentration, with the very largest utilities likely to purchase merchant plants and increase their already ample market shares. Any repeal of PUHCA will make more mergers inevitable. These factors will seriously threaten the success of SMD.”<sup>32</sup>

## Summary of the Standard Market Design

“FERC’s implementation schedule for Standard Market Design (SMD) defined in its Notice of Proposed Rulemaking (NOPR) dated July 31, 2002, was mid-2002 to mid-2003 and provides latitude for local differences and seeks input from affected parties.

The SMD proposal calls for a single set of market rules that would eliminate differences between regional electricity markets which FERC views as barriers that limit the ability of energy users to access lower-cost power resources.

FERC intends to put all U.S. transmission owners under the control of Independent Transmission Providers (ITPs) which will have broader powers than did the Regional Transmission Organizations (RTOs) they replace. The ITPs will control the transmission functions of investor-owned utilities, federal/state power authorities, power co-ops and municipal utilities. Previously, voluntary compliance in RTOs had been limited and did not necessarily include government-owned transmission. ITPs will be required to operate wholesale day-ahead and real-time power markets and push for transmission upgrades where needed

Load serving entities (LSE), which are utilities and retail power marketers, must maintain a reserve between peak demand and contracted/owned capacity (initially 12-18% but to be determined by region). In the past some LSEs paid an installed capacity (ICAP) deficiency charge to the local Independent System Operator (ISO) or other LSEs who had generation to spare, a process that was expected to, but did not succeed in attracting new generation. The ICAP approach will not be allowed under SMD.

However the ability for LSEs to cut back on power use (i.e., demand response) when called by an ITP will be considered equivalent to supply. LSEs will be charged heavy penalties (\$1 per kilowatt-hour [kWh] or more) when demand exceeds the contracted power supply, which would likely be passed on to retail customers or built into tariffs. FERC is pushing several requirements for "resource adequacy" (i.e., sufficient generation and transmission) to avoid a repeat of the California Crisis. FERC believes its proposed penalties will result in more long-term capacity contracting by LSEs to avoid such charges and in turn provide the secure revenue stream needed by merchant power suppliers to obtain construction capital for new plants.

... To properly reflect the value of transmission systems, especially where constrained, FERC seeks to employ locational marginal pricing (LMP) and Financial Transmission Rights (FTRs). “Where presently applied, LMP raises the price of power during periods and in zones where peak loads significantly exceed transmission capacity (common in many older American cities). During most of the year, LMP has little or no impact, but during hot spells (and/or when a transmission line goes down) the system can cause power prices to spike. Some see such pricing as an economic expression of the need for more local generation and transmission to reduce that impact. To avoid getting hit by such volatility, LSEs can instead purchase [FTRs] that levelize their cost to transmit

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<sup>32</sup> Overview of PS Position and Principles to Guide Consideration and Implementation of SMD November 15, 2002 [http://www.wppisys.org/media/021115\\_SMD\\_Overview.pdf](http://www.wppisys.org/media/021115_SMD_Overview.pdf)

power into a constrained area (sometimes called a "load pocket"). Doing so may create both a market and a stable revenue stream for new transmission.

FERC has also seen the need to standardize interconnection rules for distributed generation systems. While it has already put forth an order on this matter, the SMD seeks to press that issue forward as a means to improve generation adequacy, especially where transmission constraints exist and/or where supply/demand margins are tight.”<sup>33</sup>

### State Concerns Regarding Changing Roles under the SMD

Approximately 15 states indicated immediate concern calling the proposal a power grab by FERC. Less than two months after the SMD NOPR was issued, a letter to FERC, dated September 27, 2002, co-signed by one U.S. Senator and several Members of Congress representing the Northwest stated the following:

“In short, we believe this is an unnecessary, poorly conceived and dangerous academic experiment that would inject volatility and uncertainty into the comparatively stable and affordable energy system in the Northwest. We would urge the Commission to abandon the proposal.”<sup>34</sup>

The letter went on to say:

“The SMD NOPR represents an unprecedented preemption of the authority of state utility regulators.

The SMD NOPR inappropriately extends FERC jurisdiction to bundled retail customers, which has traditionally been within the sole jurisdiction of state regulators. This will complicate efforts by state regulators to protect retail customers, particularly in states that have had the wisdom not to deregulate.”

In the Northwest, 75% of the transmission is owned and operated by the Bonneville Power Administration (BPA) which voluntarily complies with Open Access Order 888 and has sales and transmission as functionally separate entities. The letter argued that there are both physical characteristics and legal obligations that prohibit the hydro system from being run to optimize power production or to respond to market signals, including flood control, navigation, irrigation, municipal and industrial water supply, recreation, and fish and wildlife protection.

Another letter to FERC dated November 15, 2002 contained the following:

“On behalf of more than 200 officials and entities that include public utility commissioners, attorneys general, local elected officials, consumer advocates, public utilities, municipalities unions and businesses, we are submitting the attached comments to the Federal Energy Regulatory Commission (FERC) on its proposed rules for standard market design.

For purposes of the required Executive Summary: these comments recommend that FERC withdraw its proposed rules on the following grounds:

- The rules constitute an over-reaching of FERC authority into retail responsibilities now executed by the states.

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<sup>33</sup> “FERC’s Standard Market Design”, Energy Users News. Lindsay Audin, January 31, 2003  
[http://www.energyusernews.com/CDA/ArticleInformation/features/BNP\\_Features\\_Item/0,2584,91491,0,0.html](http://www.energyusernews.com/CDA/ArticleInformation/features/BNP_Features_Item/0,2584,91491,0,0.html)

<sup>34</sup> Concerns in Sept. 27, 2002 letter to FERC regarding the impact of the SMD on the Pacific Northwest by Congressmen Brian Baird, Peter DeFazio, Doc Hastings, George Nethercutt and Senator Patty Murray. p.1  
[http://www.protectpowerconsumers.org/index\\_files/DeFazio%20SMD-FERC%20Letter.pdf](http://www.protectpowerconsumers.org/index_files/DeFazio%20SMD-FERC%20Letter.pdf)

- FERC bases its rules on the unjustifiable finding that a vertically-integrated utility that gives priority to its own customers engages in undue discrimination. We hope you take these comments into account when making decisions on standard market design in the coming weeks.”<sup>35</sup>

The attachment to the letter went on say:

“In meeting its obligation under the Federal Power Act, the Federal Energy Regulatory Commission fulfills a role that is critically important for electricity consumers. But the Commission’s role -- to ensure just and reasonable wholesale power and transmission rates -- is neither isolated from, nor superior to, the role that states must play to ensure fair and reliable retail service. Consumers will not be well served if the roles of the Commission and the states are confrontational. Our respective roles must be complementary. Unfortunately, in its proposed rules for a standard market design, the Commission has chosen to over-reach the authority that Congress has delegated to it, based on the Commission’s unsupported “finding” that a vertically integrated utility that gives priority to its own customers engages in “undue” discrimination.

The most profound aspect of the Commission’s proposal is its assertion of Commission jurisdiction over major elements of retail electricity service. It amounts to a transfer of authority to the Commission and a loss of control by the states over, among other things, demand forecasting, resource planning, demand-side management and marketing, and the ability to ensure that transmission is available to meet retail service obligations. The result is not only a confrontation with state law and usurpation of state ability to protect consumers at the retail level, but also immense investment uncertainty--at a time when the merchant plant industry is in crisis, and when utilities must be able to plan for and recover the costs of meeting retail needs.

... The Commission proposes to supplant state policies that protect retail consumers with new and untried institutions and rules, implementing a new and untested market theory. In the name of transforming the wholesale industry, the Commission would disintegrate our retail system, turning our joint state-federal regulatory structure on its head. By subordinating the retail system to the perceived needs of the wholesale system, the Commission has lost sight of those who should be the ultimate beneficiaries: end-use consumers--not generators who have no public service obligation and whose interests are solely commercial. A wholesale market “solution” that cripples the well-founded retail policies chosen by the elected representatives of a majority of states is not a solution at all.

... the Commission’s unprecedented and aggressive jurisdictional reach, which shifts the ground rules and undermines trust at many levels, disrupts useful aspects of the RTO process and the ability to make informed decisions.”

Some of the initial views from the states could not be termed unexpected, as the immediate concern was loss of jurisdiction. However, at least some organizations gave immediate support to the FERC initiative as can be seen from the following July 31, 2002 news release:

“The New York Independent System Operator (NYISO) praised the Federal Energy Regulatory Commission (FERC) for the decisive leadership demonstrated at today’s Commission meeting at which the Standard Market Design Notice of Public Rulemaking (NOPR) was unveiled.

Standard Market Design (SMD) is the uniform set of policies and regulations to which all U.S. electricity markets will have to adhere as the nation’s electric restructuring efforts

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<sup>35</sup> Joint Comments Urging FERC Withdrawal of Proposed Rules for FERC Standard Market Design. November 15, 2002, letter from 200 State Officials.

continue to mature. The NYISO said that the increased certainty and liquidity created by the standardization of markets is what the industry needs now.

‘While there will obviously be areas of controversy about the details of the NOPR, the bold leadership demonstrated by FERC today is the prescription needed to restore market confidence in electric industry restructuring for market participants, investors and consumers, and paint a clear and compelling roadmap for our future,’ said William J. Museler, NYISO President and CEO in preliminary comments. ‘We were also very pleased and appreciative that the FERC has apparently embraced so many of the NYISO’s existing practices and market rules in fashioning its vision.’<sup>36</sup>

However, as time went on and FERC continued to develop the SMD concept, eventually migrating to a Wholesale Power Market Platform, and as federal legislators showed support during the summer of 2003, some states have come out in full support, as can be seen from the following press release dated July 29, 2003.

‘The Mid-Atlantic Conference of Regulatory Utilities Commissioners released a resolution that:

- Commends the Federal Energy Regulatory Commission for its efforts to implement effective competitive wholesale electricity markets;
- Encourages Congress to promote a national policy of wholesale electric competition by allowing equal and open access to the interstate transmission grid and permitting the timely implementation of Standard Market Design;
- Asks Congress to resist paralyzing existing competitive wholesale electricity markets by adopting any legislative provision that delays the implementation of standard wholesale market rules or orders by the Federal Energy Regulatory Commission;
- Urges the Federal Energy Regulatory Commission to continue the implementation of rules providing for operational control and planning of the electric grid by independently governed regional transmission organizations; and
- Encourages regulators and all other participants to work together for effective and vibrant wholesale power markets.

The Mid-Atlantic Conference of Regulatory Utilities Commissioners is made up of Delaware, the District of Columbia, Maryland, New Jersey, New York, Pennsylvania, the Virgin Islands, Virginia and West Virginia. Virginia did not support the resolution.<sup>37</sup>

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<sup>36</sup>“NYISO APPLAUDS FERC’S LEADERSHIP IN DEFINING VISION FOR COMPETITIVE U.S. ELECTRICITY MARKETS”. News Release, July 31, 2002.

[http://www.nyiso.com/topics/articles/news\\_releases/2002/nr\\_073102\\_nopr.pdf](http://www.nyiso.com/topics/articles/news_releases/2002/nr_073102_nopr.pdf)

<sup>37</sup> Mid-Atlantic Utility Commissioners Issue Resolution Supporting National Standard Market Design. Tuesday July 29, 2003. [http://biz.yahoo.com/prnews/030729/dctu046\\_1.html](http://biz.yahoo.com/prnews/030729/dctu046_1.html)

## Enhanced U.S. Federal Energy Legislation

On April 11, 2003, the House of Representatives passed the Energy Policy Act of 2003 (H.R. 6) containing comprehensive national energy legislation. On July 31, 2003 the Senate passed a Bill of the same name with, some but not all, of the transmission related provisions as contained in the House Bill.

### Key elements of the House Bill:

“Amends the Federal Power Act to set forth implementation guidelines for:

- (1) Federal Energy Regulatory Commission (FERC) establishment of incentive-based transmission rate treatments to promote capital investment in electric energy transmission facilities in interstate commerce;
- (2) the siting of interstate electrical transmission facilities; and
- (3) open access transmission by unregulated transmitting utilities.

Creates a statutory mechanism for electric reliability standards incorporating Electric Reliability Organizations to establish and enforce reliability standards for the bulk-power system, subject to FERC review.

Public Utility Holding Company Act of 2003 - Repeals the Public Utility Holding Company Act.

Amends the Federal Power Act to:

- (1) direct FERC to promulgate market transparency rules governing sales of electric energy at wholesale in interstate commerce, or transmission services in interstate commerce;
- (2) prohibit round trip trading<sup>38</sup>; and
- (3) extend FERC jurisdiction to certain interstate sales of electric energy that violate FERC rules.<sup>39</sup>

The legislation also amends the Public Utility Regulatory Policies Act of 1978 (PURPA) by requiring, at the request of a consumer, real-time pricing and time-of-use metering. It also eliminated mandatory purchase and sale agreements under PURPA.

### Major aspects of the Senate Bill:

#### Amendments to the Federal Power Act to authorize FERC:

- (1) To make rules or orders to require large and/or interconnected unregulated transmitting utilities to provide transmission services: (a) at rates comparable to those that it charges itself; and (b) on terms and conditions comparable to FERC rules requiring public utilities to offer open access transmission services that are not unduly discriminatory or preferential.
- (2) To certify Electric Reliability Organizations which encourage coordination with Canada and Mexico.
- (3) To require compliance with reliability standards or charge a penalty.
- (4) Repeals the Public Utility Holding Company Act of 1935.
- (5) Amends PURPA requiring real-time pricing, time-of-use metering and net metering<sup>40</sup> if requested by a consumer. Requires interconnections to distribution grid for distributed generation projects, and eliminates mandatory purchase/sale agreements.

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<sup>38</sup> A round trip trade involves an offsetting purchase and sale without financial gain or loss undertaken with the specific intent to distort reported revenues, trading volumes or prices.

<sup>39</sup> Federal Restructuring Legislation, 108th Session of the U.S. Congress April 7, 2003

[http://www.eia.doe.gov/cneaf/electricity/page/restruct\\_bills/fedrestr108h.html](http://www.eia.doe.gov/cneaf/electricity/page/restruct_bills/fedrestr108h.html)

<sup>40</sup> Net metering provides customers with qualifying generation of (up to 10 kilowatts for residential and 500 kilowatts commercial) to offset net generation against purchases.

## Differing Viewpoints Regarding the Legislation

The Federal Trade Commission is at one end of the spectrum, and offers a mild caution against inefficiencies that may result from more regional involvement in the design and operation of markets.

“The Federal Energy Regulatory Commission's (FERC) Wholesale Power Market Platform White Paper states that FERC must harmonize its mission of achieving "wholesale electricity markets that produce just and reasonable prices and work for customers" with the new realities of regional electricity markets. ...FERC has revised its earlier standard wholesale market design proposals to give greater weight to differing regional preferences regarding market design...

...Our comment concerns four aspects of the white paper and previous elements of FERC's RTO and standard market design proposals.

- First, deference to regional economic differences and to regional timing constraints is likely to be accompanied by an increased risk of impeding efficient wholesale electric power trades, although there may also be benefits from deferring to some regional market design preferences. Variations in the design of markets within an electric interconnect may impose costs or create risks that will reduce incentives to execute efficient interregional wholesale transactions...
- Second, the revised FERC proposals present another opportunity for FERC to encourage states to focus on policies that are likely to facilitate wholesale competition and system reliability, both regionally and nationally. Accordingly, we encourage FERC to study and publicize how state programs that increase the price sensitivity of retail electricity demand can help protect customers from market power, reduce system costs, and improve system reliability.
- Third, FERC's market monitoring proposals offer several potentially useful behavioral and reporting requirements in addition to those contained in Order 2000. FERC may wish to add a requirement that market monitoring units (MMUs) use comparable data, analytical techniques, and formats in reporting to FERC and a requirement that MMUs refer likely violations of the antitrust laws to the antitrust agencies.
- Finally, we continue to believe that efficient, customer-service-oriented operation of the transmission network is an important and appropriate goal for regulatory reforms. Accordingly, we reiterate our call for FERC to include operating efficiency in its set of minimum characteristics for RTOs and Independent System Operators (ISOs).<sup>41</sup>

At the other end of the spectrum are State interests that believe State control provides greater protection for consumers, as set out in Testimony of the National Association of State Utility Consumer Advocates before a Senate Committee.

“The National Association of State Utility Consumer Advocates (NASUCA) represents state utility consumer advocates from 42 states and the District of Columbia. A Senate Bill (S.475), a recent House committee draft bill, and related staff proposals all would significantly alter the existing statutory paradigm for federal and state regulation of electricity, the primary purpose of which is to protect consumers. NASUCA opposes these proposals because they eliminate existing protections and add new risks without a clear demonstration of overriding benefit to electricity customers. While we support the reliability provisions of S.475, NASUCA generally opposes the broader proposals.

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<sup>41</sup> Federal Trade Commission Staff Comments to FERC relating to the Standard Electricity Market Design: Wholesale Power Market Platform White Paper, June 27, 2003.  
<http://www.ftc.gov/opa/2002/07/ferc.htm>

Some proposals under consideration would authorize unnecessary and costly new federal financial incentives to encourage investment in transmission facilities, beyond the level of return on investors' equity normally sufficient to achieve reliable service and just and reasonable rates. A transmission incentives proposal now under consideration by the FERX could unnecessarily add \$13 billion to consumers' bills, and should not be ratified by new legislation.

The need for consumer protection against market power and prevention of utility holding company abuses remains. Yet some recent legislative proposals would have eliminated FERC merger review authority, and some current proposals would repeal the Public Utility Holding Company Act of 1935 (PUHCA). Despite unenthusiastic enforcement, PUHCA and FERC merger review authority are prophylactic measures discouraging the exercise of market power and re-creation of interstate utility holding company empires. Accordingly, NASUCA has concluded that the passage of electricity legislation along these lines would not be in the overall interests of utility consumers.<sup>42</sup>

### FERC's Roadmap for State and Regional Participation in SMD

While many states lacked enthusiasm for SMD which they saw as FERC usurping them of jurisdiction, legislators at the federal level were anxious for some agency to have the ability to solve issues across regions (and the country). The challenge becomes finding a way to assure the states have meaningful say within the FERC's defined SMD framework.

A formal process whereby states representatives will participate in the decision-making of regional transmission organizations and other regional entities was set out in section 1211 of an early Senate Staff Discussion Draft of legislative changes, and summarized by the Chairman of FERC as follows:

"States [would be authorized] to enter into agreements to establish 'Regional Energy Service Commissions (RESC).' A RESC would be composed of one member from each State in the RESC, appointed by the governor as provided by state law. A RESC could be vested with jurisdiction over, *inter alia*, transmission planning and siting, interconnection of generation facilities to the interstate transmission grid, rate design and revenue requirements for transmission and wholesale sales, incentive rates for transmission, market power review and market monitoring, formation and approval of 'Transmission Organizations,' reliability standards and rules, and adequate enforcement mechanisms.

A RESC or State regulatory authority may petition the Commission to resolve a conflict on transmission of electric energy or wholesale power sales between adjacent regions. Public utilities in States in a RESC would not be subject to commission authority under Federal Power Act (FPA) Part II, except for...

The Commission has long supported regional efforts, including Regional Transmission Groups in the early 1990's, Independent System Operators (ISOs) in Order No. 888, and Regional Transmission Organizations (RTOs) in Order No. 2000. More recently, we have supported greater state involvement in RTO policies through Regional State Committees (RSCs) and Multi-State Entities (MSEs). All of these efforts recognize that power systems are regional, and most significant policy issues must be addressed on a regional basis by entities with accountability to make the system work. The RESC proposal appears to recognize the regional nature of today's power systems and is

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<sup>42</sup> Testimony of Gerald Norlander for the National Association of State Utility Consumer Advocates Regarding Senate Bill S.475, Electric Transmission and Reliability Enhancement Act of 2003 Before the Committee on Energy and Natural Resources, United States Senate, Washington DC, March 27, 2003 <http://www.nasuca.org/filings/testimony-32703.pdf>

consistent with the goal of establishing better regional governance to solve regional problems. Certainly FERC would have less of a void to fill if regional problems are resolved in the regions. Therefore, I support the objectives of the RESC proposal and would like to help advance regional governance to address regional issuers.”<sup>43</sup>

Mr. Wood went on to explain various complexities associated with establishing RESCs expressed concern with certain specifics, and although the proposal was not included in the Senate’s final bill, the above discussion represents a generic vision for State involvement.

### FERC’s Wholesale Power Market Platform – April 28, 2003

On April 28, 2003 FERC issued a White Paper on the Wholesale Power Market Platform. Following eight months of discussion and feedback, FERC had modified its Standard Market Design concept as outlined in its NOPR of July 31, 2003 to a new vision. The following comparison between the SMA and FERC’s Wholesale Power Market Platform is taken from a summary prepared by the Steel Manufacturer’s Association (SMA), with additional information from an article prepared by the Northwest Power and Conservation Council noted in footnotes.<sup>44</sup>

“Earlier this year, in response to heavy political pressure, FERC Chairman Pat Wood agreed to slow down the Standard Market Design (“SMD”) rulemaking process and issue a paper previewing the final SMD rule...

The White Paper marks a significant retreat on many features of SMD, indicating that FERC had no choice but to concede to Capitol Hill and Western and Southern state opposition to FERC’s effort to set uniform wholesale market rules. The White Paper explains that the final rule will be designed to establish a customer-based “Wholesale Market Platform.” Following are the major provisions of the White Paper:

- The SMD proposed to require a structural separation of transmission and power market functions by giving transmission owners a date certain to join or form Independent Transmission Companies. FERC had proposed this as the only way to finally end gaming opportunities by transmission owners (i.e., use control of the grid to favor their generation and other interests). The White Paper abandons this requirement. Instead, jurisdictional utilities will be required to join Regional Transmission Organizations (“RTOs”) or Independent System Operators (“ISOs”). RTOs and ISOs must comply with the less stringent requirements of FERC Order No. 2000’s required characteristics and functions, except that ISOs will not be required to meet the scope and configuration requirement.
- The SMD proposed that FERC would exercise jurisdiction over bundled retail transmission. In the White Paper, the Commission states that it will exercise jurisdiction over the non-rate terms and conditions of service for bundled retail sales, but the transmission rate component of bundled retail sales will remain under the jurisdiction of the states.
- Regional state committees<sup>45</sup> may determine whether an RTO or ISO will use a “license plate” or “postage stamp” rate design. If the regional state committee is

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<sup>43</sup> Testimony of Pat Wood, III, Chairman of FERC Before the Committee on Energy and Natural Resources, United States Senate, March 27, 2003

<http://www.ferc.gov/press-room/ct-current/03-27-03-wood.pdf>

<sup>44</sup> FERC Market Design White Paper Summary - Northwest Power & Conservation Council

[http://www.nwcouncil.org/energy/transmission/fercmarketdesign/2003\\_04WhitePaper.htm](http://www.nwcouncil.org/energy/transmission/fercmarketdesign/2003_04WhitePaper.htm)

<sup>45</sup> State Committees would participate in RTO decision-making on issues including: (1) the regional proposals for cost responsibility, including whether participant funding would be used for new transmission and whether license plate or postage stamp rates would be used for access fees; (2) whether firm transmission rights would be allocated to customers or assigned; (3) the resource adequacy approach that

unable to reach a decision on which methodology to use, the RTO or ISO would file its own proposal pursuant to section 205 of the Federal Power Act.

- Regional transmission planning and resource adequacy will be left to the state and local governments, with FERC playing only a supporting role.
- The SMD NOPR's elaborate market power mitigation procedures have been eliminated. Instead, individual RTOs and ISOs will be charged with developing their own procedures. Each RTO and ISO will also have to have an independent market monitor.

Each RTO and ISO will be required to have a real-time spot market for energy to resolve imbalances, and each RTO and ISO will develop its own detailed market rules to be included in its tariff. Spot markets operated by the RTO or ISO must facilitate the ability of demand to respond to prices...

- The SMD NOPR required the use of locational marginal pricing ("LMP") to deal with congestion. The White Paper eliminates the LMP requirement, and states that regions should develop their own congestion management systems. RTOs and ISOs that elect to use LMP to manage congestion would be required to make firm transmission rights ("FTRs") available to customers, but auction of FTRs would not be required. In short, systems for addressing congestion, and how to relieve it, may vary by region.<sup>46</sup>
- If an RTO or ISO can demonstrate that the costs of implementing any feature of the Wholesale Market Platform outweighs its benefits, the Commission would not require implementation of that feature for that particular RTO or ISO. This invites regional variation on a host of unspecified issues.
- In the White Paper, the Commission went to great lengths to accommodate regional variation and accentuate the role of the states, hoping to assuage concerns that the final SMD rule would be a major federal power grab. In the process, however, the Commission appears to have given up (at least for the time being) on its vision for standardized wholesale energy markets nationwide.

... The White Paper repeats FERC's support for the participation of demand response in the wholesale markets, but the Commission notes that state action is required for retail customers to have demand response options. This position suggests that FERC may be relinquishing the initiative in this matter.

SMA has also advocated a real-time energy market to settle imbalances to replace the current punitive, asymmetrical "Schedule 4" imbalance provisions contained in the pro forma tariff. The SMD NOPR required a real-time energy market, and the White Paper indicates that this requirement will remain in the final rule.<sup>47</sup>

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will be used across the region; and (4) overseeing the transition process to ensure that existing rights holders get equivalent firm RTO transmission rights, including rights for load growth.

<sup>46</sup> Will require congestion management approaches meet certain principles in order to have transparent market mechanisms with efficient price signals and to be compatible within an interconnection. The White Paper will require RTOs to operate real-time imbalance energy markets from the beginning and day-ahead and ancillary service markets conditionally.

The White Paper dropped the minimum level of resource adequacy requirement of the SMD, leaving the approach to and level of resource adequacy to be set by the regional state committees.

<sup>47</sup> Steel Manufacturers Association May 2003 Energy Update - FERC Unveils White Paper on Wholesale Power Market Design. <http://www.steelnet.org/new/20030508.htm>

## Canadian Viewpoint of FERC role in Domestic Transmission Matters

Canadian electric utilities are aware of the complexity of the North American Continental grid as emphasized below.

“Electricity infrastructure underlies every aspect of our economy and society. Possibly the largest machine in the world, its transmission lines connect all generation and distribution on the continent; a hierarchical network”<sup>48</sup>

The complexity of the grid can easily be forgotten because it performs remarkably such a high percentage of the time. However, grid failure that was such a shock and an extreme rarity in 1965 in the US Northeast and was still rare at the time of the 1977 New York Blackout, is no longer a rarity. The California energy crisis, the US Northeast/Ontario blackout of August 2003, and reminders from other places like the power outage in Italy in September 2003 are increasingly frequent reminders of the fragility of transmission systems everywhere. Beyond the need for Canadian utilities to be FERC compliant for U.S. market access, the utilities are aware that improvements will result from changes to the market rules that can be instituted now... while new transmission facilities will take years to construct.

The position of various Canadian jurisdictions may be gleaned from the following references:

### National

The Minister of Natural Resources Canada made the following remarks to in a speech to the Toronto Board of Trade on September 6, 2001:

“... [The] long-term American Energy Policy ... clearly calls for more U.S. imports of energy... and the major initial preoccupation is electricity.

...We must also insist upon U.S. respect — respect for Canadian energy needs and priorities, our sovereignty, our federal/provincial/territorial jurisdictional prerogatives, our regulatory authorities, our commitment to sustainable development.

Respect also for a rules-based trading system, with market access secure against U.S. protectionist flare-ups, and reliable contracts upon which to base long-term investments.

We should fully expect the United States to promote their national interests and, on our side, we must be equally aggressive and proactive in putting Canada's vital interests front and centre.

From the very beginning of our dialogue with the Bush Administration, we have been very clear about one fundamental point — we are not talking about a so-called "North American energy policy" which implies some form of policy subordination. What we want is the expansion and successful functioning of North American energy markets. And the two are quite different.

... From that experience and from U.S. policy pronouncements, it is clear that Canada should expect important new electricity marketing opportunities in the United States. This could be especially valuable in terms of the hydro-power potential in Newfoundland, Quebec, Manitoba and British Columbia. It also underscores the importance of Ontario Power Generation's nuclear revitalization.

Indeed, almost every province has expressed an interest in pursuing new supplies to meet greater export demand.

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<sup>48</sup> Electric Power Research Institute (EPRI) 1999 Presentation on Complex Interactive Networks and Systems Initiatives: Self Healing Infrastructures  
[http://www.usna.edu/EPNES/epri\\_CINSI\\_NSF\\_4\\_99.pdf](http://www.usna.edu/EPNES/epri_CINSI_NSF_4_99.pdf)

Today, there is tremendous momentum ... toward a restructured competitive electricity supply industry, with market forces at play for greater efficiency, and with greater integration across jurisdictions and internationally.

How will inter-connected jurisdiction co-operate with each other?

How can market rules be made compatible, while fully respecting each jurisdiction's regulatory authority?

To start with — we need to resolve the matter of "wheeling" within Canada — that is, the effective transmission of power from one system, through another jurisdiction, to a third market — without trade impediments domestically. ...

International markets will not stand still. The stakes are high. If Canadian suppliers are to be significant players, and if Canada is to influence the cross-border rules of the game — the wheeling issue and the Internal Trade Agreement must be settled quickly!

There's also the issue of greater access to the existing power grid, within each jurisdiction, for potential new power suppliers. Some progress has been made for new access for certain green-power producers and co-generation facilities — but more is certainly possible, to take full advantage of export market opportunities.

Also outstanding is the issue of reliability standards for the full elective power system. That has been a voluntary system, but the Americans are now planning to enact mandatory standards. The U.S. Federal Energy Regulatory Commission (the FERC) is also moving ahead on a new structure for transmission systems — to be known as Regional Transmission Organizations.

All of this will impact on us.

A collaborative fed/prov working group is now consulting with our Canadian industry to assess the inter-jurisdictional issues in moving to mandatory reliability standards. We have developed some common Canadian principles. There is support at all levels on the Canadian side for an International Self-Regulating Reliability Organization to develop and enforce mandatory standards.

In the U.S., they are still debating this issue, but they appear to be tending toward a stronger role for their FERC in carrying out this function. That could, indeed, be problematic for us. And it's a key issue I will be discussing next week with all my provincial and territorial energy counterparts. We need to position ourselves, collectively, to defend and advance our common interests in dealing with our U.S. inter-connections.

One final point about electricity markets and deregulation — the California experience surely demonstrates how not to do it. It was a case of extraordinary bad management.

... Canadians need to study the California experience to ensure it doesn't happen here.<sup>49</sup>

A National Energy Board news release dated Jan.23, 03 backgrounder on Transmission and Regional Transmission Organizations (RTOs) stated:

“The structure of the North American transmission grid is being reshaped by the FERC RTO and Standard Market Design (SMD) initiatives. Many market participants believe that RTO development will promote trade by increasing access and lowering transmission costs.

Practically all provinces have expressed interest in some form of participation in RTOs. Manitoba has already concluded a coordination agreement with the Midwest Independent System Operator and B.C., New Brunswick and Nova Scotia have supported RTO membership. Québec, Ontario and Alberta are assessing their strategic options. Apart from the technical challenges posed by the implementation of SMD, or achieving

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<sup>49</sup> Comments by The Honourable Ralph Goodale, the Canadian Minister of Natural Resources. Address to Toronto Board of Trade, September 6, 2001  
[http://www.nrcan.gc.ca/media/speeches/2001/200162\\_e.htm](http://www.nrcan.gc.ca/media/speeches/2001/200162_e.htm)

operational compatibility with SMD, concerns in Canada have been raised with respect to regulatory sovereignty, RTO governance, and ensuring that the interests of Canadian consumers are not compromised.

Canadian entities have also identified the need for more transmission to the U.S. as a means to foster future trade. To improve access to U.S. markets, a number of new transmission projects have been proposed over the past two to three years. An innovative aspect of some of these proposals is that they would be merchant power lines, targeting specific export markets.”<sup>50</sup>

### **British Columbia**

An article in the Vancouver Sun dated June 29, 2003, which included an interview with the BC Minister of Energy, contained the following:

“A recent National Energy Board report noted that the power industry across North America is undergoing substantial change as many jurisdictions --including Alberta, Ontario and Quebec -- introduce competition in generation and access to some wholesale and retail markets.

The report says events in Canada are driven in part by developments in the United States, where the Federal Energy Regulatory Commission (FERC) is changing the rules that allow competition in the world's biggest electricity market.

For better or for worse, British Columbia is part of a newly created electrical grid organization, the Western Electricity Coordinating Council, which encompasses 71 million people living in the western half of North America, from B.C. to Mexico.

...Reforms continue south of the border as FERC looks to create a stable price and supply environment for the public and for industry.

...One of the conditions of western grid membership is that B.C. Hydro voluntarily put its transmission system under control of a non-profit organization.

What the Americans don't like to see is a company that uses its monopoly position on transmission lines to extract higher prices from power generation companies that want to feed into it --they compare it to a company that owns a highway and won't let other company's trucks drive on it, with consumers being the losers.

‘Real, transparent and open access to B.C. Hydro's transmission lines is a key driver for developing B.C. electricity policy,’ said Austin. ‘without it, B.C. Hydro risks losing its access to the U.S. market.’

‘In theory this access is supposed to exist today, but in practice B.C. Hydro uses every trick in the book to maintain monopoly control -- including requiring expensive studies to determine whether there is any space available, and requesting third parties to pay for improvements that B.C. Hydro would have to make as part of its routine maintenance program.’

Under the government's new scheme the independents would sell directly to buyers as far away as California because B.C. Hydro will no longer have control over who can or cannot feed into the high voltage transmission lines that carry electricity in and out of the province.”<sup>51</sup>

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<sup>50</sup> National Energy Board News Release, January 23, 2003.  
Transmission and Regional Transmission Organizations, Backgrounder  
[http://www.one-neb.gc.ca/newsroom/releases/2003/nr0305\\_e.htm](http://www.one-neb.gc.ca/newsroom/releases/2003/nr0305_e.htm)

<sup>51</sup> “Hydro Must Break Up” Vancouver Sun interview with Richard Neufeld, BC Energy Minister  
Saturday, June 29, 2002. [http://www.sqwalk.com/Simpson\\_Sun\\_20020629\\_HydroMustBreakUp.htm](http://www.sqwalk.com/Simpson_Sun_20020629_HydroMustBreakUp.htm)

In a May 2, 2002 presentation by the BC Ministry of Energy and Minerals to the Western Governors' Association Workshop on North American Free Energy Trade, the role BC plays in and with the energy policy of the US, with focus on electricity, was outlined as follows:

**“How does BC involve itself?**

- We voluntarily agree to play the U.S. rules
  - o Powerex, BC's export crown corporation, voluntarily agreed to be licensed by the federal government of the US.
  - o Powerex holds a FERC marketers certificate and BC Hydro agrees to operate as a functionally separate - as any other US utility.
  - o BCUC has adopted FERC standards for wholesale transactions as their own and takes on the FERC role in BC.
- This raises a major issues from BC's perspective
  - o Being a foreign country/province we generally don't have a voice in the decisions made by US federal government - that affect us.
- However, that does not keep us from being active participants in the US federal processes.
  - o We intervene and participate in FERC dockets
  - o We participate in the FERC rule makings, and
  - o We have worked on federal legislation back in Washington DC – a two pronged approach that involved a federal-provincial process through Ottawa and the Canadian Ambassador in Washington DC; and through our membership and association with WIEB and CREPC (14 years!)
- We participate in government to government dialogues and discussions...
- We participate in industry to industry standard setting
  - o This relationship was established over 30 years ago ...
  - o WECC now has 3 BC board seats that will set reliability standards
- We are willing to go so far as putting our transmission system under the control of an independent operator as part of RTO West and are working in BC to figure out how to make this work while maintaining our political sovereignty.

**What have we learned?**

- If you participate you can influence
  - o We can and have created innovative organizations that allow for fair participation on an international basis
- This takes along time and a lot of resources, and if often frustrating, but can be very productive and rewarding”<sup>52</sup>

**Ontario**

The President and CEO of the Ontario Independent Electricity Market Operator (IMO) made the following comments at a Massachusetts Electricity Restructuring Roundtable.

**CONSISTENT RULES – IS THERE AN OPTION?**

“When it comes to the LONG TERM future of the North American electricity market, be it from the perspective of trade or reliability and mutual support, you are either in or you are out and the rules and standards that will determine this are being developed now.

On May 1<sup>st</sup> this year we are opening our market to both wholesale and retail competition. On day 1 – we will have 262 participants in the wholesale market. Also, close to 1 million customers have already signed contracts with retailers.

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<sup>52</sup> British Columbia's Participation in U.S. Electricity Policy – May 2, 2002 Presented By, BC Ministry of Energy and Minerals to Western Governors' Association Workshop on North American Free Energy Trade.  
<http://www.westgov.org/wieb/meetings/boardsprg2002/briefing%20materials/energy%20trade/bc&us.htm>

First of all let me note that the IMO is very much equivalent to an RTO in the U.S....

Amongst the duties of the IMO are the following:

- Continue the development and evolution of the market and its rules and processes
- The IMO board approves the rules on market opening
- Build the necessary systems to support a reliable market
- Educate and train staff and participants
- Direct the operation of the wholesale electricity system
- Operate wholesale electricity markets
- Invoice customers and pay suppliers
- Ensure compliance with the rules
- Carry out market surveillance to identify flaws in the market and gaming
- Coordinate operations with neighbouring jurisdictions
- Carry out technical impact assessments of proposed facility additions
- Assess adequacy of supplies over a period up to 10 years
- Assess adequacy of delivery and request preparation of plans by transmitters
- Provide expert technical support to the REGULATOR
- Encourage investment.

These duties very closely match the role of RTOs and in some instances ARE PERHAPS BROADER.

Let's get something straight, the development of rules that impact over a broad regional area is not new. Neither is Ontario's influence in this domain new and neither is the impact of such broader planning and operation on Ontario new.

Consider; the vast majority of interconnections in place today were built with regional cooperation, and by the way, for the sake of mutual support from a reliability perspective.

These interconnections then paid for themselves several times over due to the amount of trade carried out, inter-jurisdictionally, from Ontario's perspective this was both imports and exports....

The world is changing – and new rules are being developed. We cannot sit back and take as a given that IN Ontario WE will continue to have the influence that we have had in the past to ensure that international rules will be developed in our interests. This will only occur if we are active in showing leadership and participating in this domain. What is most important is not the existence, size or number of RTOs. What's important is consistency of rules that allow the ability to take advantage of available resources, reduce pancaking of transmission charges and drive down costs.

It is important that we maintain an involvement in the evolution of the electricity marketplace structure to ensure that we can take care of Ontario's interests, not only in the near term but also over the longer term. Remember that in our business, problems can move at the speed of light across the continent.

This is why I think it important FOR US IN ONTARIO to participate in FERC's hearings into the RTO future in the U.S. and in examining what are the necessary features for an effective and efficient marketplace. It is why we see it as critical that we sit at the table with New York and New England to WORK ON the rule development in the northeast. We do have some features in our market which I believe are at the leading edge of market design in North America. One example is the way the IMO can poll meters and set necessary standards.

As the rules change, we are not just looking at the compatible needs of future markets for the sake of reliability, quality and cost optimization. We are ALL looking to ensure that we don't lose the benefits that have been available and used time after time.

Let me be clear. I believe that we can be an effective party to the development of regional and international rules and standards in the new competitive regime. We do not

have to adopt identical rules. In Ontario, as elsewhere, I expect that there will be good rationale to support LOCAL variations in rules. We are not, and will not, become FERC jurisdictional. I do however believe that rules that eliminate artificial barriers and facilitate mutual support will be in the best interests of ALL....

If we are to encourage this investment to be made in Ontario, we have to create the conditions that make it attractive. Clearly, several considerations including taxes and environmental rules play a part in this but I BELIEVE the ability to use the Ontario network as a hub, CONNECTING THE NORTHEAST WITH THE MID-WEST, with rules that facilitate trade is also a key factor. Without this the investment may be made elsewhere and Ontario could ultimately find itself as a long term, dependent, importer of power.<sup>53</sup>

A slide in the presentation by the Ontario IMO to the Ontario Power Summit, June 11, 2002 outlined Ontario's involvement in RTO developments to include:

- "Submissions to FERC on: design/allocation of functions/standards development
- Participation in Northeast evolution: MOU agreement, mediation at FERC, NERTO design, seams mending at FERC (June 12)
- Discussion with MISO
- Review of emerging standards'<sup>54</sup>

These activities demonstrate the extensive involvement of the Ontario IMO with FERC in the shaping of the regional electricity market.

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<sup>53</sup> CONSISTENT RULES – IS THERE AN OPTION?

Massachusetts Electricity Restructuring Roundtable Presented by: Dave Goulding, President and CEO, Ontario Independent Electricity Market Operator [March 15, 2002]  
[http://www.raabassociates.org/Articles/Roundtable\\_Goulding\\_3-15-02.doc](http://www.raabassociates.org/Articles/Roundtable_Goulding_3-15-02.doc)

<sup>54</sup> Ontario: Straddling the Northeast and Midwest RTOs

Presentation to the Ontario Power Summit. June 11, 2002  
[http://www.theimo.com/imo\\_web/pubs/media/speech\\_PowerSummit\\_Shalaby\\_2002jun11.ppt](http://www.theimo.com/imo_web/pubs/media/speech_PowerSummit_Shalaby_2002jun11.ppt)

## Literature Review – Part 2

### Transmission Rights

Review of the Legislative and Regulatory Framework shows that open, non-discriminatory transmission access is the norm in most of North America. It is expected that most of the outstanding barriers will be resolved when FERC sets down the final rules for the Wholesale Power Market Platform. With open access as a given, attention must move to the issue of transmission rights. A transmission right relates to who has priority when there is congestion on the transmission network, and at what price. If at certain times (of the day, week, month, year) there is more load required at a location than there is transmission capability to supply, one would say that the line is totally congested. If the Load Serving Entity (LSE) has a firm commitment to supply a customer at all times... some mechanism must exist to guarantee the supply. A Firm Transmission Right (FTA) owned by the LSE will guarantee that load will not be cut when the line becomes congested. It is a necessary tool in order for markets to operate in a dependable way.

The issue of transmission rights has been discussed for many years, and an initial concern with the formation of ISOs, was that transmission rights have the potential to present market power difficulties as holders of the rights could manipulate the markets.

“In the short-run, poorly implemented transmission rights can impact the efficiency of the marketplace in three ways.

1. The withholding of transmission rights into a given zone in order to increase the value of local generation resources.
2. The withholding of transmission rights into a given zone in order to increase the value of the transmission rights themselves.
3. The withholding of generation output in order to capture the congestion revenue that would otherwise accrue to the owner of a transmission right.”<sup>55</sup>

FERC presented views on FTRs in a “Working Paper” dated March 15, 2002, and in an “Options Paper” Dated April 10, 2002. Recently, it presented additional views in its White Paper on the Wholesale Power Market Platform dated April 28, 2003 (as well as in the Appendix to that paper), and in a staff discussion document. Subsequently, several parties have made comments to FERC on the issue. These views will be summarized in this section of the Literature Review.

The Working Paper set the stage as follows:

“At present there is no single set of rules governing transmission of electric energy. The electrons moving across the grid do not distinguish between bundled retail and other services, and behave according to the laws of physics rather than the laws of a particular jurisdiction. With more non-integrated electricity suppliers and a deeper reliance on wholesale electric markets, there are substantial competitive consequences and higher costs to all retail customers if we do not apply consistent, non-discriminatory rules to all transmission customers. To protect all customers and assure the benefits of competition for all, consistent transmission rules must be applied. ...

Market design flaws are visible in every regional electric market today under the existing tariff. These flaws are allowing operational problems such as the “socialization” or “uplift” of congestion management prices across all customers in a region, which

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<sup>55</sup> See Transmission Rights and Market Power James Bushnell University of California Energy Institute, Berkeley. *Discussion Draft, October 1998*  
[http://faculty-gsb.stanford.edu/wilson/archive/E542/classfiles/trans\\_rights2.pdf](http://faculty-gsb.stanford.edu/wilson/archive/E542/classfiles/trans_rights2.pdf)

obscures the potential for price signals to indicate where new generation, demand response or transmission is needed. ...

Network Access Service would give the customer the right to transmit power between two points, a source and a sink. A source is defined here as the location where a transaction originates, and a sink is defined as the location where a transaction terminates. ... A Network Access Service customer would have access to all sources and sinks on the system. An access charge would be used to recover the embedded costs of the transmission system. The manner in which embedded costs will be recovered requires further discussion to be resolved.

... Network Access Service gives customers two options for how to handle the costs of this congestion, either: (1) a predetermined price, using "transmission rights," or (2) the applicable congestion charge in which the customer bears the full cost of congestion management. The issue of how to allocate transmission rights is difficult and contentious. However, our intent is to preserve the existing rights of current users of the system.

...A customer can achieve price certainty for Network Access Service by acquiring transmission rights. A transmission right allows the customer to schedule power from specific source(s) and sink(s) without having to pay congestion for service between those points. Anyone can hold a transmission right. A key implementation issue will be the initial assignment of transmission rights. One option is to directly allocate the transmission rights to customers that pay the embedded costs of the system. Any transmission rights not claimed by these customers would be auctioned. Another option would be to conduct an auction to apportion the transmission rights, with the proceeds from the auction allocated to those customers that pay the embedded costs of the system.”<sup>56</sup>

The Options Paper elaborated as follows:

“The Working Paper... identifies several issues that require further discussion. These issues involve embedded cost recovery under the proposed Network Access Service and transition issues involved moving to one tariff for all service. Specifically, the issues are: 1) the manner in which embedded costs of the transmission system will be recovered; 2) the manner in which Transmission Rights will be allocated among customers; and 3) the transition of customers under existing contracts (real or implicit) to the new service. ...This paper identifies options the Commission has for resolving these issues.

...A Network Service customer pays a monthly demand charge based on its load ratio share of the transmission provider's monthly transmission revenue requirement. The customer's load ratio share is based on the customer's hourly load coincident with the transmission provider's monthly transmission system peak. The Point-to-Point firm customer pays a monthly demand charge for each unit of capacity that it has reserved. Non-firm Point-to-Point customers pay a charge for the capacity reserved for the service. ...

The Working Paper proposes to blend these three types of service into a new Network Access Service that could be purchased by load serving entities as well as non-load serving entities. The service could be used to move power between two points, a source and a sink. A Network Access customer would have access to all sources and sinks on the system. Under the Network Access Service there would be two types of transmission related rights. The first is the Access Right, i.e., the right to move power between any two points on the system. The second is the Transmission Right, i.e., the right to a predetermined price for service between two specific points on the system (the customer does not have to pay congestion charges for service between those two points). Either the Access Right or the

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<sup>56</sup> Federal Energy Regulatory Commission Working Paper on Standardized Transmission Service and Wholesale Electric Market Design. March 15, 2002  
[http://www.westgov.org/wieb/meetings/crepcsprg2002/briefing%20materials/smd\\_paper.htm#Transright](http://www.westgov.org/wieb/meetings/crepcsprg2002/briefing%20materials/smd_paper.htm#Transright)

Transmission Right could be used as the basis for recovery of the embedded costs of the transmission system. ...

An access charge would be used to recover the embedded costs of the system...

... under the current rate designs, a user that transmits power from one system to another pays two transmission charges to recover the embedded costs of the system from which power was exported as well as the embedded costs of the system where power is delivered to load. In designing the rates for Network Access Service, the rates could be designed to continue the payment of multiple transmission charges or they could be designed so that only one transmission charge is paid.

There are three main issues in designing the access charge: 1) who pays the access charge for deliveries within the transmission provider's system?; 2) should the access charge apply to exports and wheel throughs?; and 3) is the charge billed based on peak load or actual usage? ...

[Specifically, the options presented for discussion were:]

Who pays the access charge for deliveries within the transmission provider's system?

Option 1: Access charge applies to anyone that schedules deliveries within the transmission provider's system, whether it be an import, service between a receipt and delivery node in the system, or purchases of power by load from the energy markets. ...

Option 2: Access charge is paid only by customers that take power off the grid. ...

Option 3: Payment of access charges and the receipt of Transmission Rights or the auction revenues from those rights would be linked together. ...

Should the access charge apply to exports and wheel throughs?

Option 1: The access charge would apply to these transactions. ...

Option 2: The access charge would not apply to these transactions. ...

Option 3: The access charge would not apply to individual transactions. But, there would be an annual revenue adjustment. ...

Option 4: A lower access charge would apply to exports and wheel throughs than for deliveries within the transmission provider's system. ...

Is the access charge billed based on peak load or total usage?

Option 1: Use monthly peak load for billing the access charge. ...

Option 2: Use annual peak load for billing the access charge. ...

Option 3: Bill the access charge for each MWh used. ...

Transition of Customers under Existing Wholesale Contracts and Bundled Retail Customers Load to Transmission Service under the Revised Pro Forma Tariff. ...

Option 1: All service occurs under an open access transmission tariff at the time standard market design is implemented. ...

Option 2: Convert all customers taking bundled retail service upon implementation of standard market design and provide strong incentives for customers under existing contracts to convert. ...

Option 3: Allow regional variations. ...

Allocation of Transmission Rights ...

Should historical customers get the initial Transmission Rights ? ...

Option 1: Convert existing customers' usage to the initial Transmission Rights. ...

Option 2: Give all customers that pay access charges the same rights to Transmission Rights.

If existing customers are given the initial conversion rights, how should Transmission Rights be allocated? ...

Option 1: Assign rights based on existing contract rights and historical usage. The Commission could assign the Transmission Rights based on existing sources and sinks in Point-to-Point contracts and the designated resources for Network Integration Service and bundled retail load. In essence, those customers that currently are using those points for firm service would get the right to continue to use those points without paying for congestion. In some cases, the requests for existing customers for Transmission Rights between specific points may exceed the Transmission Rights that can reliably be granted. In that case, actual usage of those points in a recent historical period could be used to allocate the rights among existing customers. Usage of the system particularly by network customers changes over time. For example, peak load may increase more rapidly in one service territory than another. Or, the load of the traditional utility may decrease because of state retail choice programs. Consequently, the allocation of Transmission Rights may need to be regularly adjusted to ensure that there continues to be an equitable allocation of Transmission Rights.

This approach comes closest to replicating the rights customers currently have under existing contracts or for bundled retail load. However, under this methodology it may be difficult for new entrants to acquire Transmission Rights.

Option 2: Auction Transmission Rights and assign the auction revenues based on existing contract rights (real and implicit). Under this approach all Transmission Rights would be auctioned. This way the entity that values these rights the most would obtain them. New entrants and existing customers could obtain Transmission Rights through the auction. The revenues from the auction would be allocated to existing contracts, primarily load. This would serve to reduce the total transmission costs including congestion costs paid by these customers. Under an auction methodology load could ensure that it gets the Transmission Rights by bidding high in the auction.

Theoretically, Options 1 and 2 should produce the same end result if there is a secondary market for trading Transmission Rights. However, some existing customers have expressed doubts that it would. They are not certain that the auction revenues would cover the congestion costs they may face. Additionally, there has been a more active secondary market for Transmission Rights where there is an auction for Transmission Rights (NYISO) rather than an allocation of Transmission Rights (PJM).

The auction methodology may be preferred by load in states that have had significant divestiture of generation. In those states, this methodology may give load a better ability to hedge congestion costs when buying from a variety of suppliers. ...

Option 3: Partial allocation and auction. As a transition mechanism, the Commission could permit a combination of the two methodologies. For example, 75% of the rights could be allocated and 25% could be auctioned with the revenues allocated to existing customers. Over time, an increasing amount of the Transmission Rights could be auctioned. This method provides some opportunity for new entrants to acquire Transmission Rights through the auction. It also gives existing customers allocated Transmission Rights for most of their load to provide a transition to a more competitive wholesale market.

## **Comments by the Ontario IMO**

On April 30, 2002, the Ontario Independent Electricity Market Operator made a submission to FERC with comments on the April 10<sup>th</sup> Options Paper. Comments of the IMO included the following:

### **“IMO Criteria Used for Selecting Options**

The options paper anticipates issues that must be resolved early to enable the standard market design. The IMO, in indicating its views on the options, showed preference for options that promote easier inter-regional integration, and are essential platforms for the standard market design.

The IMO appreciates the Commission’s continued efforts to solicit input on various options for resolving rates and transition issues in the standard market design. Our submission below outlines our preferred options and elaborates on the reasons for selecting them.

### **I. Changes Proposed in the Current Services and Recovery of Transmission Revenue Requirements**

Who pays the access charge for deliveries within the transmission provider's system?

*The IMO favours Option 2: Access charge is paid only by customers that take power off the grid:*

- (a) Charging only the load customers in the RTO would promote regional scope in securing wider access to suppliers located outside the RTO. Purchases from outside suppliers would be treated on the same basis as internal transactions involving suppliers within the RTO, as there would be no differential in transmission costs.
- (b) The benefit of not charging suppliers the embedded costs of the existing network is that a fixed charge component could adversely distort the way suppliers bid into a competitive marketplace since they would be expected to recover the fixed transmission cost component.
- (c) Transmission service is ultimately paid by electricity consumers, either directly, or indirectly, therefore, it is desirable to avoid the distortion mentioned earlier.

Should the access charge apply to exports and wheel-through?

*The IMO favours Option 4 to start with and Option 2 as an ultimate goal: An interim lower access charge would apply to exports and wheel throughs (EWT) than for deliveries within the transmission provider’s system and ultimately the access charge would not apply to these transactions.*

- (a) In the longer term, the elimination of exports and wheel throughs charges is desirable. It will inevitably tend to be based on reciprocal treatment by neighbouring jurisdictions or on incremental costs for congestion, but without a contribution to embedded network infrastructure costs.
- (b) Imposition of a fixed charge for exports and wheel throughs for the long-term would distort the auction/sale of FTRs and lead to rate “pancaking”, and reduction in trade opportunities.
- (c) A reasonably low priced export and wheel through charge as an interim measure would not inhibit the further development of more efficient pricing regimes.
- (d) The interim export and wheel through charge should be set at the low end of the range of tariffs in other interconnected jurisdictions, until transition time schedules permit full elimination.

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56. FERC Options Paper – April 10, 2002 - Options for Resolving Rate and Transition Issues in Standardized Transmission Service and Wholesale Electric Market Design  
[http://www.westgov.org/wieb/meetings/crepcsprg2002/briefing%20materials/options\\_paper.htm#transrights](http://www.westgov.org/wieb/meetings/crepcsprg2002/briefing%20materials/options_paper.htm#transrights)

Is the access charge billed based on peak load or total usage?

***The IMO favours Option 1: Use monthly peak load for billing the access charge:***

- (a) Charge determinants based on peak demand have stronger link to cost of service for network transmission where costs are largely fixed.

## **II. Transitioning of Customers under Existing Wholesale Contracts and Bundled Retail Customers to Transmission Service under the Revised Pro Forma Tariff**

***The IMO favours Option 1: All service occurs under an open access transmission tariff at the time standard market design is implemented:***

- (a) It is the best platform for implementation of the standard market design.
- (b) It eliminates the confusion and onerous effort of trying to integrate the physical reservation for transmission with the schedules that result from the bid based, security constrained real-time dispatch mechanism.
- (c) Assuming “one-stop” shopping is desirable for billing and collecting a uniform network access transmission service charge, this option is a relatively straightforward way for the RTO to bill and collect the charge.

## **III Allocation of Transmission Rights**

Should historical customers get the initial Transmission Rights?

***The IMO favours an evolution from Option 1 to Option 2: Initially, consider conversion of existing customers’ usage to the initial Transmission Rights and then move to giving all customers that pay access charge the same rights to Transmission Rights:***

- (a) Ontario has not had the opportunity to explore this issue in detail, as locational marginal pricing (LMP) is not yet in place within this province. If an assessment of congestion warrants it, the IMO may implement a form of LMP within Ontario at the wholesale level. As such time, we would expect some form of evolution from Option 1 to Option 2 on Financial Transmission Rights.

If existing customers are given the initial conversion rights, how should Transmission Rights be allocated?

***The IMO favours an Alternate Option as the ultimate goal: Auction Transmission Rights and assign the auction revenues that are in excess of congestion payouts to the transmission customers as credits to reduce the embedded charges.***

- (a) The auction process will provide a more robust market for FTRs in that it allows the maximum number of transmission rights to be offered to market participants at prices that reflect the value to buyers.
- (b) The auction process will enable the development an efficient congestion management system in that it would provide immediate and correct price, enabling all market participants to assess the value of the transmission service.
- (c) Allocating rights and surplus revenues to transmission customers ensures that all transmission customers receive some benefit from these surplus revenues. In the event of construction of new transmission facilities that add transfer capability outside of rate bases, the entity that funds the “merchant” construction should receive the additional transmission rights associated with the new transfer capability. ...”<sup>58</sup>

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<sup>58</sup> Ontario IMO Comments in Submission to FERC on Market Design and Structure April 30, 2002  
[http://www.theimo.com/imoweb/pubs/corp/RM01-12\\_Comments\\_MarketDesignOptions.pdf](http://www.theimo.com/imoweb/pubs/corp/RM01-12_Comments_MarketDesignOptions.pdf)

## **Comments by PJM Interconnection**

On May 3, 2002, PJM Interconnection filed comments on FERC's April 10<sup>th</sup> Options Paper.<sup>59</sup> It agreed with Ontario that transmission service charges be paid only once, it suggested by the Load Serving Entity (comparable with Ontario's saying customers).

It suggested that bundled retail customers be under the pro forma tariff, and grandfathered customers be given a strong incentive to convert. It made the observations that the proportion of grandfathered load is small, and that its bundled retail loads have had a chance to protect themselves from congestion costs with fixed transmission rights, and that nearly all LSEs had taken advantage of that opportunity.

PJM suggested an auction model after initial allocation of transmission rights (and in fact it has since implemented the auction model in its jurisdiction).

## **Comments by the Transmission Access Policy Study Group (TAPS)**

On May 2, 2002, TAPS submitted extensive comments on FERC's April 10, 2002 Options Paper. Excerpts appear below:

“... the Commission's initiative can succeed only if designed to:

- honor the existing transmission rights that support the ability of LSEs to serve their loads at stable transmission prices from their existing resources, and
- require the transmission planning and expansion necessary to ensure the transmission adequacy and price stability required to support investment in new generation needed to serve growing loads and to provide reliable service.

The interwoven objectives of transmission and generation adequacy dictate that:

- (1) RTOs must have a clear transmission planning and expansion obligation; and
- (2) Network access service must provide a mechanism that assures LSEs the ability to secure long-term transmission at stable prices necessary to support long-term generation investments.

Today, OATT network integration service allows an LSE to develop a portfolio of resources that it can economically dispatch to serve its aggregated load with reasonable price certainty and delivery assurance. The key to the process is planning: the transmission provider is required to plan for a network customer's load; once a network resource designation is accepted for firm service, it is incorporated into the base case for planning the transmission system. LSEs will be discouraged from making the long-term commitments necessary to support new generation (by construction, or purchase from a competitive supplier) if they are at risk of not being able to secure firm transmission delivery of new resources to load with reasonable price certainty on a long-term basis, *i.e.*, if they must repeatedly outbid others for FTRs over the life of the resource. ...

Given the objectives of ensuring a robust grid and maintaining the benefits of network integration service, we answer the Commission's questions as follows:

- (1) Load (for whom the grid is planned) should bear most of the cost of the grid (based on monthly peak load), but consideration should be given to a rate design that assigns a portion of the embedded cost of the grid to generation (to help deal with the “export generation” issue both intra and inter-RTO). Through charges pose difficult issues requiring the balancing of consideration of cost causation and equity with concerns about the market-constricting impacts of pancaked rates.

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<sup>59</sup> Comments Of PJM Interconnection , L.L.C. On The Commission's Options Paper On Rate And Transition Issues  
<http://www.pjm.com/documents/downloads/ferc/2002docs/may/20020503-elec-market-design.pdf>

- (2) Bundled retail load should be subject to the same tariff as unbundled retail and wholesale load, while those with grandfathered contracts should be strongly encouraged (but not forced) to convert to the new network access service, by (among other things) modeling that service closely after OATT network integration service.
- (3) FTRs should be assigned to those with existing firm rights (by virtue of grandfathered agreements or OATT network service agreements and associated network resource designations, point-to-point reservations, or transmission provider network resource designations), and historical usage.
- (4) Generation adequacy will be supported by a strong RTO commitment to transmission planning and expansion and the price stability needed to support new generation investment. These requirements can best be achieved by tying assignment of long-term FTRs to network resource designation and the planning process. TAPS supports capacity reserve obligations. However, the appropriate approach to implement such obligations is not clear, and may be subject initially to regional variation, with state input.

#### I. INTERESTS OF TAPS

TAPS is an informal association of transmission-dependent utilities (“TDU”) in more than 30 states, promoting open and non-discriminatory transmission access. As entities entirely or predominantly dependent on transmission facilities owned and controlled by others, TAPS members are vitally interested in issues of industry structure and have strongly supported the Commission’s initiative to form truly independent, regional transmission organizations. ...

#### II. POLICY PERSPECTIVE: SMD MUST SUPPORT TRANSMISSION ADEQUACY AND STABILITY OF TRANSMISSION PRICES NEEDED TO SUPPORT GENERATION ADEQUACY, AND ENABLE LSEs TO RELIABLY SERVE LOADS AT REASONABLE COST

...If the Commission assures LSEs the long-term transmission availability and price stability necessary to support and finance new long-term generation commitments, the generation adequacy the Commission is seeking will be less elusive; and most importantly, consumers will enjoy reliable service at reasonable cost, as well as the efficiencies of a vibrant LMP-based short-term energy market.

##### **A. LSEs’ existing ability to flexibly and economically serve load from existing resources must be preserved**

TAPS strongly agrees that “Customers under existing contracts (real or implicit) should continue to receive the same level and quality of service under standard market design” (SMD Working Paper at 7) and supports the Commission’s stated “intent ... to preserve the existing rights of current users of the system” (*id.* at 8). Such preservation is critical to those, like TAPS members, who have fought hard for their transmission rights (*e.g.*, through antitrust cases), and who have invested billions of dollars in generation on the basis of these firm service commitments. Of critical importance is the right to use network service to economically integrate geographically-dispersed network resources to serve their loads on an aggregated, rather than “point-to-point” basis. Dilution of the transmission rights on which LSEs have reasonably relied to serve load is likely to significantly increase costs to LSEs and end use customers, and undermine reliable service.

As discussed below and in our SMD Working Paper Comments (at 14-24), to preserve the level and quality of existing service, under both grandfathered contracts and OATT service agreements for network integration and point-to-point service, the Commission must require assignment of FTRs (in the form of options) to reflect existing rights to use transmission service and preserve the characteristics of network integration service. Network access service that provides only a right of access and a right to bid for FTRs will

severely hamper the ability of LSEs to economically serve load. If network access service is merely a dressed-up form of point-to-point service, it will destroy the comparability we fought so hard to achieve through network integration service. ...

**B. RTOs must have a clear planning and expansion obligation**

For SMD to succeed, it must be accompanied by a strong transmission planning obligation so that the infrastructure needed to support competitive markets and new generation is likely to be built.... Letting the profit motives of individual market participants control the design, location and timing of transmission additions will not work. ...

**C. Network access service must include a mechanism that ensures stable transmission prices.**

Stability of transmission prices and confidence in the availability of long-term firm service is necessary to support investment in new generation resources needed to provide generation adequacy. The Commission should take care in developing a new service that these elements are preserved. The sheer promise of “access” subject to congestion at an unspecified price will not support the many billions of dollars of generation investment that the nation requires and, more specifically, that LSEs need to meet their continuing service obligations.

... network access service provides “access” to all sources and sinks, but with no firmness or price protection except to the extent customers obtain transmission rights. This can create substantial risks that will discourage LSEs from making generation investments unless they can be assured of obtaining long-term FTRs. LSEs will be reluctant, and sometimes unable, to finance and construct new generation if their ability to obtain transmission for the resource depends on outbidding other market participants for FTRs potentially on an annual basis, or face crushing congestion charges. To support generation investment, LSEs need to be able to obtain long-term transmission for new resources at a known, reasonable price. Risk reduction mechanisms, such as long-term FTRs tied to network resource designations, should be part of network access service.

**III. ACCESS CHARGE RECOVERY OPTIONS**

**A. Who pays the access charge for deliveries within the transmission provider’s system?**

... TAPS supports a variation on Option 2 for allocation of access charges for deliveries within an RTO: Access charges should be paid by all customers that take power off the grid, who would in turn have rights to (a) an allocation of FTRs to reflect existing rights and uses, for the full term of the transmission rights and associated generation rights; (b) have their reasonable requirements, including their need to access competitive markets, taken into account in the planning process; (c) have the ability to secure long-term FTRs in connection with the network resource designation process, consistent with the planning; and (d) have the transmission revenue requirement reduced by the revenues associated with the auction proceeds of any FTRs not allocated. ...

**B. Should the access charge be applied to exports and wheel throughs?**

... It is appropriate for transmission providers to recover some costs from the wheel-through transactions that they support, and to have incentives to invest in facilities to support efficient levels of wheel-through service. Some TAPS members support Option 1, believing as a matter of equity and cost causation that through customers should bear a portion of the embedded costs of the transmission system. ... other TAPS members favor a form of Option 2 where charges for through service at least equal the incremental costs of providing the service, congestion charges, and losses. It would also be appropriate for these charges to recover any incremental transmission facility capital and maintenance costs associated with through service, especially where the through service impacts the planning process.

### **C. Is the access charge billed based on peak load or total usage?**

As noted above, TAPS strongly favors network access service that includes a clear obligation to plan for the needs of LSEs, and to connect the FTR assignment process to the planning process. From that vantage point, Option 1 – continuation of the monthly peak load billing methodology contained in the OATT network integration tariff – seems most appropriate to reflect this planning model-based form of network service. Use of monthly peak loads is consistent with the planning process and the realities of transmission usage.

Use of monthly peaks allocates fixed costs in a fair way, taking account of the relative demands of users in different seasons. The monthly load ratio billing also provides an assurance of revenue recovery that the financial community values, thereby increasing bond ratings and decreasing the capital cost of grid expansion.

TAPS strongly opposes adoption of a single annual peak approach (Option 2). ...

### **III. TRANSITION OF CUSTOMERS UNDER EXISTING WHOLESALE CONTRACTS AND BUNDLED RETAIL CUSTOMERS**

It is essential that bundled retail and wholesale load be placed under the same tariff as applies to unbundled retail service as well as wholesale service, as proposed in both Options 1 and 2. Otherwise, comparability between transmission owners serving bundled retail and others will never be achieved. Competitive markets, and efficient use of the integrated grid on which all users must rely, require a non-discriminatory set of rules of the road. Failure to place bundled retail load under the tariff has the perverse incentive of rewarding transmission owners that retain ownership of their transmission, rather than divesting to a independent transmission company.

This issue is of particular importance to TAPS members who compete at retail with transmission owners or serve at wholesale distribution utilities who compete with the surrounding transmission owner. It is also essential to making retail access work in states that have chosen that option.

Option 1, with all load taking service under the tariff, is plainly the end state toward which the Commission should be moving. However, Option 2 is the most appropriate way to get there. Rather than abrogate contract rights, the Commission should provide strong incentives for customers under existing wholesale contracts to convert.

The key to inducing voluntary conversion is to make network access service attractive to load serving entities, by featuring the network integration service attributes discussed above, with a strong obligation to plan for LSE needs, including new long-term network resource designations, with allocation of FTRs flowing from this robust planning process. It is also crucial that the incentives offered those with grandfathered contracts not discriminate against those whose contractual entitlement to service is under a service agreement under OATT network integration service, as required since Order 888. This issue appears well-suited to being addressed generically, rather than being left to regional variation.

### **V. ALLOCATION OF TRANSMISSION RIGHTS**

TAPS agrees with the Options Paper (at 11) that the initial allocation of Transmission Rights among customers is primarily a question of equity, not efficiency. Basic fairness requires that historical customers receive the initial Transmission Rights, and that those rights be allocated by assignment, not auction. As noted above, a regimen designed for transmission and generation adequacy will also make provision for new resource designations, and assignments of FTRs, in connection with the planning process.

### **A. Should historical customers get the initial Transmission Rights?**

TAPS strongly prefers Option 1, which would convert existing customers' usage to initial Transmission Rights. As explained in TAPS' SMD Working Paper Comments (at 20-24), this approach is essential to preventing an unfair burden on customers who have long supported the transmission grid and who have properly supported their resource planning and generation investments with long-term firm transmission reservations pursuant to pre-OATT contracts or network resource designations under the OATT. While some reallocation may be needed during the term of the initial Transmission Rights to recognize retail access, basic fairness requires that they be assigned for the full term of existing firm transmission agreements and associated generation rights. The initial Transmission Rights must be designed to reflect the network nature of the pre-existing service, and to preserve customers' rights.

Option 2— giving all customers that pay access charges the same rights to Transmission Rights — is totally unacceptable. This option represents an unjustified abrogation of contract rights, and it would undermine existing customers' reasonable investment-backed expectations. The Options Paper itself acknowledges (at 12) that the approach would effect a cost-shift and “would likely significantly increase the costs of transmission service ... to end-use customers.” There is no basis for transferring wealth to new entrants in this manner, at great cost to the consumers this Commission is statutorily mandated to protect.

### **B. If existing customers are given the initial conversion rights, how should Transmission Rights be allocated?**

As explained in its Working Paper Comments (at 22-23), TAPS supports Option 1, which would assign initial Transmission Rights based on existing contract rights and historical usage. Implementing a mandatory auction mechanism for initial Transmission Rights unnecessarily increases the uncertainty, risk, and transaction costs to those who must depend upon the grid to provide service to their customers. If the auction method proves effective, a *voluntary* auction will be able to realize the potential benefits of mandatory auction, while avoiding the pitfalls. ...<sup>60</sup>

### **Comments of CREPC 18 Months Earlier**

A good discussion relating to the preservation of existing rights preceded the above papers by about 18 months, and appears in a November 13, 2000 draft paper entitled “Transmission Pricing in the Western Interconnection”. It contained a detailed discussion relating to fairness based on historic usage to serve native load and other thoughts that have reappeared (albeit less well explained) in more recent writings including the White Paper on Wholesale Power Market Platform. A few paragraphs are quote below:

#### **“D. Preservation of existing rights as FTRs.**

A major issue in negotiations over the formation of RTOs is the question of how to translate the set of rights and contractual agreements that have developed under the existing system into a set of rights under the new regime. This issue has several aspects.

- First, the basic problem of figuring out who has what rights in the existing system, and how they add up and compare to the capacity of the relevant portions of the transmission system, is not a simple task. Indeed, there is some evidence that existing utility practices have led to an over-allocation of transmission rights.
- Second, there has been little agreement about the extent to which such existing rights should be protected after RTO formation. Some parties want to see as many rights as

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<sup>60</sup> Comments of the Transmission Access Policy Study Group on the April 10, 2002 Options Paper. Submitted to FERC May 2, 2002. [ Paper available from FERC web site, no direct link found. ]

possible made available to the market, while others are greatly concerned about the potential effect on their continued obligation to provide bundled retail service under state law.

- Third, those rights which are to be protected would need to be translated from contract path rights under the existing scheduling system into rights across multiple flow paths under a flow-based system.

The first issue involves *looking at historic patterns of use for serving native load and disentangling contractual rights*. Service of native load by a utility's own generation has always been handled implicitly by flow-based congestion management through redispatch, but the patterns of use have always varied with time of day and year. Contractual rights for wheeling across another party's system have in some cases been contract path rights, and in others, network rights. Some transmission-owning utilities have been providing re-dispatch free of charge to their own merchant function, to third parties with schedules across the transmission owner's system, and in some cases, to third parties that do not have schedules across the transmission owner's system. As a result, it is likely to be impossible to establish multiple feasible dispatches for each participating transmission owner that is also feasible for the entire RTO system.

The second issue involves decisions on *whether and how preexisting contracts and load service obligations are to be protected*. Setting aside a portion of the capacity of the transmission network for their exclusive use would result in maximum protection for existing uses, but would leave little in the way of available capacity for the market. Assigning FTRs that mimic the historic use they have made of the system would ensure that the maximum amount of transaction capacity is denominated in standardized, tradable instruments, but would entail some risks for those companies with continued contractual or regulatory obligations. Assigning rights to auction revenues instead of the FTRs themselves might result in still more risk for those companies, but would have additional liquidity benefits in providing a market test for historic uses of the system, while still enabling companies to fulfill their obligations by enabling them to outbid other uses through the revenue crediting mechanism. These issues are important because they relate to the likely degree of liquidity of the market for FTRs, discussed below.

The third issue involves the *conversion of historic rights into flow-based rights*. This requires agreement on a model of the transmission grid that is simple enough to be computable and to result in a manageable number of flow paths and FTRs. It requires decisions on the state of the system to be used for calculating flows (all transmission lines in service or some lines out for maintenance; settings on phase shifters; etc). It requires decisions on how many historic flow patterns to model (hourly vs. peak/off peak/shoulder vs. seasonal).

The final issue involves the disposition of the residual FTRs after calculation of the rights of native load and preexisting contracts. If residual rights are deemed to belong to transmission owners they must be placed in an auction and released to the market. Failure to do so would preserve the ability of transmission owners to withhold access of competitors to their markets, a situation that FERC has repeatedly concluded cannot be allowed to stand and one that has led FERC to issue Order 2000 on the formation of RTOs.<sup>61</sup>

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<sup>61</sup> Transmission Pricing in the Western Interconnection - A draft paper by the CREPC Transmission Pricing Work Group. November 13, 2000 [ Text layout modified to add emphasis. ]  
<http://www.westgov.org/wieb/electric/Transmission%20Pricing/pricing.pdf>

## **TAPS Views on Congestion Revenue Rights FERC Technical Conference**

TAPS further stressed the importance of protecting firm transmission rights of existing customers at a December 3, 2002 FERC Technical Conference:

“TAPS members’ primary responsibility is to provide reliable service and stable electric prices to consumers within the areas which they serve. To meet these obligations, they have made major generation investments and significant purchased power commitments that never could or would have been made without simultaneously obtaining transmission rights or constructing transmission facilities to be able to deliver these resources to their customers with reasonable price certainty. They will require similar delivery assurance to make and finance resource commitments needed to serve their loads in the future.

For [Standard Market Design] SMD to work for [Load Serving Entities] LSEs and to protect consumers from significant increases in the delivered price of electricity during this transition, two requirements are absolutely essential. SMD must provide the assurance of long-term transmission, with price certainty, needed to:

- (i) protect all existing firm transmission rights obtained to meet service obligations, whether derived from pre-Order 888 contracts or OATT network service; and
- (ii) accommodate the commitment to and financing of new long-term resources that LSEs need to continue to meet their service obligations. To accomplish these fundamental objectives, the Commission must impose the following requirements:

**Principle 1: There must be no diminution of the ability of LSEs to utilize existing resources with existing transmission rights to serve load on a long-term basis.**

Corollary 1: Preexisting firm service commitments should not be abrogated; there must be no arbitrary sunsets.

CRRs<sup>62</sup> should be allocated for the full term of existing transmission rights and associated generation. A twenty-year CRR, much less a one- or five-year CRR that the NOPR seems to contemplate (p 249), is no substitute for the thirty-five year firm transmission right on which an LSE financed a base load coal plant.

Corollary 2: CRRs required to support today’s firm transmission reservations should be assigned, even if not simultaneously feasible.

LSEs should be assigned the CRRs necessary to retain the existing transmission rights that currently support billions of dollars of generation investment. There is something fundamentally wrong with a “new, improved” system of assigning transmission rights if it does not support preexisting firm transmission rights LSEs currently depend upon to serve load from network resources at a reasonable cost. Even if not simultaneously feasible 8760 hours of the year, these existing firm rights are accommodated by the transmission system today, with virtually no interruptions as evidenced by the rarity of TLR 5 events. Those depending on existing firm reservations should not be forced to accept fewer CRRs based on a simultaneous feasibility determination designed to assure self-funding of the congestion management system. The financial integrity of the congestion management system can be maintained without depriving LSEs of the firm transmission rights that support their past resource investments. As a transitional measure, until transmission upgrades are put in place to support the simultaneous feasibility of all existing firm transmission reservations, any congestion management revenue shortfall associated with supporting existing transmission rights should be rolled into the revenue requirement in at least the same pricing zone(s) that bears that cost today, if not more broadly. The RTO

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<sup>62</sup> A Congestion Revenue Right (CRR) is an earlier term that was used for the concept that is not referred to as a transmission right.

should identify flowgates that contribute significantly to such revenue shortfalls and place such flowgates on its “top priority” list of needed transmission upgrades.

Corollary 3: CRRs for existing uses of the system must be options not obligations.

The firm transmission rights LSEs have today are options, not obligations. While CRR obligations may be appropriate for new resources to which commitments are made with full knowledge of the nature of these rights, conversion of existing rights into CRR obligations violates the “no diminution” principle. The substitution of obligations for the existing option-type rights LSEs now enjoy will increase cost and risk to LSEs and their customers.

Corollary 4: CRRs for existing network resources should be assigned, not subject to mandatory auction. TAPS members are not speculators. We need to obtain and hold CRRs for network resources necessary to meet long term obligations. Any CRR auction should be voluntary, not mandatory.

**Principle 2: LSEs must be able to obtain long-term CRRs on a basis that supports financing of and commitment to new long-term resources needed by LSEs to meet obligations to reliably serve growing loads and maintain resource adequacy.**

Corollary 1: Assignment of new long-term CRRs must be tied to designation of network resources.

To finance the new generation necessary to make SMD work, LSEs need the ability to secure long-term CRRs to support new long-term power supply commitments. This can best be achieved by allocation of CRRs in connection with a network resource designation process, consistent with regional transmission planning, for the term of new purchase contracts or life of new generation.

Corollary 2: CRRs must match the amount and duration of the designated network resource.

The CRRs assigned during the network resource designation process should provide for delivery to the LSEs’ load of the full capacity of a network resource, up to the life of the resource commitment.”<sup>63</sup>

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<sup>63</sup> SUMMARY OF TAPS POSITION FOR CONGESTION REVENUE RIGHTS FERC  
TECHNICAL CONFERENCE DECEMBER 3, 2002  
<http://www.tapsgroup.org/Congestion%20Revenue%20Rights.pdf>

## **Firm Transmission Rights As Addressed in FERC's White Paper on the Wholesale Power Market Platform, and Follow-Up Comments**

In the first section of this report FERC's White Paper on the Wholesale Market Platform was discussed in terms of the overall framework from a legislative and regulatory point of view. This section will elaborate on the content of the paper in relation to transmission access rights, which will be followed by comments by various interested parties to the proceeding, and what was contained in the House and Senate Bill HR6. This discussion will not reach back into the Standard Market Design NOPR of July 31, 2002, because the updated view has progressed to such an extent that a discussion of the earlier view would only add confusion.

### **The White Paper**

The White Paper itself stated the following:

“As with our earlier restructuring efforts in the natural gas and electric power industries, we want to ensure that existing customers retain their existing transmission rights and retain rights for future load growth. While all customer that pay a basic access charge can schedule transmission service, it is important that customers be able to protect themselves from congestion costs through Firm Transmission Rights (FTRs). The Final Rule will eliminate any requirement that FTRs be auctioned. We will, instead, look to regional state committees to determine how such rights should be allocated to current customers and on current uses of the grid. Varying approaches to FTR allocation need not create “seams” with neighboring regions. ...

### **Firm Transmission Rights**

RTOs and ISOs that use locational pricing to manage congestion would be required to make Firm Transmission Rights (FTRs) available to customers. FTRs protect customers from the costs of congestion. Under the Wholesale Power Market Platform, customers in RTOs that use locational pricing along with network transmission service would have firm physical transmission service, and customers with FTRs would be protected for congestion costs.

We would not require auctions of these rights. FTRs allow customers to schedule service according to the paths specified in their rights, with no risk of congestion charges. There also would be no risk of curtailment, absent a force majeure event such as the loss of a transmission line. By providing protection from congestion costs, FTRs also allow market participants to enter into contracts with a locked-in price if desired. Thus, FTRs allow for maximum utilization of valuable scarce grid capacity and therefore lower costs to customers.

In the Final Rule, for RTOs or ISOs that have not already addressed this issue, these rights would be allocated according to existing contracts and existing service arrangements in order to hold customers harmless. To the extent transmission rights have already been approved by the Commission in RTO or ISO orders we would not override these decisions in the Final Rule.”<sup>64</sup>

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<sup>64</sup> FERC Wholesale Power Market Design Platform – White Paper – April 28, 2003. (pages 5 & 10)  
[http://www.ferc.gov/industries/electric/indus-act/smd/white\\_paper.pdf](http://www.ferc.gov/industries/electric/indus-act/smd/white_paper.pdf)

## **The White Paper Appendix 1**

Appendix 1 of the White Paper, (comparing the proposed Wholesale Market Platform with the RTO requirements of Order No. 2000, provided the following clarification with regard to responsibilities for Regional State Committees (RSCs) to decide upon, and where the RTO or ISO would file proposals if the RSCs could not reach a decision:

“The transition process that will be used in the region to ensure that each existing firm customer receives FTRs or ARRs, based on the regional choice, equivalent to the customer’s existing firm rights. This includes whether any revenue shortfalls would be recovered through an uplift charge that applies to all customers in the region or over a narrow class of customers, e.g., only to customers in certain zones within the region.”<sup>65</sup>

### **Taps Comments on the White Paper**

A submission to FERC on July 25, 2003, entitled TAPS COMMENTS ON WHITE PAPER: FTR ISSUES – July 25, 2003, contained the following:

“The Transmission Access Policy Study Group submits these limited comments on one crucial aspect of the Commission’s April 28, 2003 Wholesale Power Market Platform White Paper: FTRs...

#### **I. THE COMMISSION’S COMMITMENT TO PRESERVE EXISTING TRANSMISSION RIGHTS MUST BE REAL**

TAPS members were comforted by the White Paper’s unequivocal commitment “to ensure that existing customers retain their existing transmission rights” (at 5) and its pledge to “hold customers harmless” (at 10, emphasis added):

‘Under the Wholesale Power Market Platform, customers in RTOs that use locational pricing along with network transmission service would have firm physical transmission service, and customers with FTRs would be protected from congestion costs.

... FTRs allow customers to schedule service according to the paths specified in their rights, with no risk of congestion charges. There would also be no risk of curtailment, absent a force majeure event such as the loss of a transmission line.

... In the Final Rule, for RTOs or ISOs that have not already addressed this issue, *these rights would be allocated according to existing contracts and existing service arrangements in order to hold customers harmless.*’

The White Paper’s Appendix provides specific assurance that LSEs’ existing rights would obtain full protection through allocation of FTRs.

‘If an RTO or ISO uses locational pricing, it must ensure that each existing firm customer (including transmission owners with a service obligation for native load) has the opportunity to obtain FTRs equivalent to that customer’s existing firm rights. We will ensure not only that existing customers retain their existing rights, but also that they have the ability to obtain rights for future load growth. Customers who paid for transmission for load growth can retain the FTRs for that capacity. The FTRs that are offered by the RTO or ISO must, in the aggregate be consistent with the physical limitations of the transmission system.’

TAPS was therefore surprised and disturbed to read the Staff Paper, which appeared to suggest that pro ration may still be an acceptable option for a region to propose to the Commission. The Staff Paper (at 21) starts out consistent with the White Paper:

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<sup>65</sup> Comparison of the Proposed Wholesale Market Platform with the RTO Requirements of Order No. 2000. (Page 17) [http://ferc.gov/press-room/pr-current/White\\_Paper\\_Appendix\\_A.pdf](http://ferc.gov/press-room/pr-current/White_Paper_Appendix_A.pdf)

‘The conversion of existing rights to FTRs is important because customers with current rights want assurance that these rights will not be diminished in the conversion process. The White Paper offers such assurance but leaves to the regions, particularly the RSCs, to devise the method.’

The Staff Paper explains why, if the grid supports all existing firm rights today, there might not be enough simultaneous feasible FTRs to satisfy all rights. It then notes ‘several ways that a region could convert existing rights to FTRs without diminishing existing rights,’ offering two examples that it characterizes as “consistent with the White Paper proposal:

1. *All* pre-existing physical rights would be honored regardless of their initial physical simultaneous feasibility’; the RTO would create counterflow rights or pay a generator to create counterflow, uplifting the charge to all transmission customers.
2. Some pre-existing rights would remain physical and would be honored without conversion to FTRs.

The Staff Paper then identifies a third approach ‘that does not necessarily ensure that all existing contracts are honored,’ which has been used in New England, New York and PJM: Only simultaneous feasible physical rights are converted to FTRs, with the result that existing rights are prorated. It states ‘The Commission ...would consider requests from other regions to follow such an approach.’

The Commission should quickly disavow the Staff Paper’s suggestion that it maybe permissible for regions to adopt an FTR allocation methodology flatly inconsistent with the White Paper. The Commission must be absolutely clear that it will not approve new FTR allocations that conflict with the White Paper’s policy of protecting existing transmission rights. The Staff Paper’s identification of pro ration as an option that the Commission is willing to consider in regions other than the three where FTRs have already been allocated will make it harder for regions to come together on the hard task of making the White Paper’s full preservation commitment a reality. Confusion on this crucial subject is deadly to the consumers that the Commission has a statutory obligation to protect.

Nor should there be any confusion as to the length of the commitment to preserve existing transmission rights. FTRs must be assigned to each LSE, up to the LSE’s peak load, for the full amount and term of the existing transmission rights and associated resource. A 20-year FTR — much less a one- or five-year FTR that the NOPR seems to contemplate (P 249) — is no substitute for the 35-year firm transmission right on which an LSE financed a base load coal plant.

To maintain existing levels and quality of service (NOPR P 15(8)), TAPS has urged the Commission to provide for conversion of existing transmission rights to options. The firm transmission rights LSEs now enjoy are effectively options, not obligations; whether under grandfathered pre-OATT contracts or the OATT, they provide a complete hedge against congestion costs in the direction of the transmission reservation, but carry no risk of payment if that congestion happens to reverse. TAPS appreciates that the use of options, rather than obligations, will make it harder to accommodate the FTRs required to support existing firm transmission rights. While some or all LSEs in some regions may find use of obligations acceptable, LSEs should not be forced to choose between foregoing FTRs or accepting obligation FTRs that would subject them to significantly higher cost or risk. ... Even where a region generally adopts an obligations approach, the Commission should be vigilant to ensure that each LSE, based on evaluation of its individual circumstances, is in fact ‘held harmless’ by the conversion to FTRs ‘equivalent’ to their existing rights, as the

White Paper (at 10) and its Appendix (at 7) promise. The availability of options will also be necessary to induce those with grandfathered contracts to convert to tariff service.

... The White Paper (Appendix at 16-17) gives Regional State Committees ('RSCs') 'primary responsibility' for determining the regional proposal for 'ensur[ing] that each existing firm customer receives FTRs ... equivalent to the customer's existing firm rights. This includes whether any revenue shortfalls would be recovered through an uplift charge that applies to all customers in the region or over a narrower class of customers, e.g., only to customers in certain zones within the region.' See also White Paper at 5.

... Further, state commissions are not subject to the Commission's statutory mandate under the FPA. Each state commission's duty is focused on protecting the state's retail ratepayers subject to state PUC jurisdiction —often just the customers of the state's investor-owned utilities. They may not be too concerned that municipal and cooperative FTRs may be pro-rated, so long as the large IOUs, whose generation is mostly on their system in any event, are kept whole.

Nor is it clear RSCs will work, especially on issues with different subregional impacts. If an RSC decides to govern itself by majority, or even super-majority (but not unanimous) vote, the interests of small states, or small groups of market participants, may get overridden even if they merit protection under the FPA. The Commission cannot abdicate its responsibilities to ensure just, reasonable and not unduly discriminatory service to those customers in the minority state(s). Tyranny by the majority is not an acceptable standard for action under the FPA. TAPS strongly urges the Commission to make good on its White Paper commitment to protect existing rights.

## II. THE WHITE PAPER'S 'NO MANDATORY AUCTION' COMMITMENT MUST BE REAL

## III. THE COMMISSION SHOULD CLARIFY ITS PROVISIONS REGARDING FTRs FOR LOAD GROWTH AND NEW RESOURCES

In the White Paper (Appendix at 7-8), the Commission promises:

We will ensure not only that existing customers retain their existing rights, but also that they have the ability to obtain rights for future load growth. Customers who paid for transmission for load growth can retain FTRs for that capacity.

The Appendix further explains (at 8):

The RTO or ISO tariff must also offer customers the ability to obtain additional FTRs for load growth. Customers paying the access charge would have the right to receive the additional FTRs associated with transmission upgrades that are included in the regional transmission plan.

TAPS assumes that the Commission by these statements intends to provide network customers that have paid, and through the access charge continue to pay, the residual costs of the grid on a long term basis, with a right to receive allocations of FTRs to meet load growth. Such a reading would also be consistent with the White Paper's robust planning and expansion process (see Appendix at 13), which TAPS also supports:

The RTO or ISO must also be responsible for transmission planning, and for directing or arranging, necessary transmission expansions, additions, and upgrades that will enable it to reliably and economically serve the needs of all customers in the region, including historical and native customers and their projected load growth. The RTO or ISO would include transmission upgrades in the regional plan

that are necessary to maintain or improve reliability or to reduce congestion and improve access to lower cost supplies (economic enhancements).

Economic enhancements would be included in the regional transmission plan with the costs recovered through the license plate or postage stamp access charge, if it is prudent to do so from the perspective of native load in the region.

TAPS assumes that 'native load' as used in the White Paper includes transmission native load, including TDUs (who have borne their fair share of the infrastructure costs for decades), rather than just the power customers of the transmission owners.

The White Paper provides little guidance on how these load growth/new resources FTRs would be assigned. TAPS again urges the Commission to tie the assignment of long term FTRs (up to the amount and the duration of the resource) to the network resource designation process, which in turn should be tied into the planning process. Maintaining a close connection between the network resource designation process and the allocation of FTRs provides a workable framework for assigning load growth FTRs. And most fundamentally, only through such mechanisms can LSEs obtain the long term transmission rights required to support the long term generation commitments (and financing) required for resource adequacy and to meet state law obligations to serve load economically and reliably.”<sup>66</sup>

The TAPS paper exemplifies the tone of many of the comments submitted to FERC in reply to the White Paper. All comments may be viewed on the FERC e-library web site.

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<sup>66</sup> **TAPS COMMENTS ON FERC WHITE PAPER: FTR ISSUES – August 6, 2003**

(Footnotes from the TAPS text have been omitted, to read footnotes see original text.)

<http://www.tapsgroup.org/030806%20FTR%20Issues.pdf>

## **NB Power Views Re: Grandfathering of Transmission Capacity Reserve Agreements**

As a witness for NB Power, James Hoecker, former Chairman of FERC, filed evidence dated September 29, 2003 on the subject of the grandfathering of Transmission Capacity Reserve Agreements. The hearing to review Section 2.1 of NB Power's Open Access Transmission Tariff commenced on October dd/mm/2003.

Excerpts from Mr. Hoecker's evidence follows:

"NB Power has been guided in part by the restructuring policies of the U.S. FERC because New England represents an important market for Canadian electric power. The New Brunswick Board of Commissioners of Public Utilities ('PUB') is positioned to consider those policies, including their effect on the New Brunswick and Canadian power markets and whether the U.S. market policies are appropriately implemented in this case. I am therefore submitting evidence about the purpose and content of the FERC's decision. Specifically, my evidence will focus on FERC's policies governing the 'grandfathering' of existing transmission contracts that were entered into before issuance of Order No. 888 and whose terms extend beyond 1996.

... Order No. 888 made no distinction between existing transmission capacity contracts between affiliates and non-affiliated third parties. Even with regard to agreements entered into after Order No. 888 went into effect, the Commission did not limit the ability of affiliates to contract with one another. The FERC principles of non-discrimination and comparable service established by order No. 888 applied in all cases, however.

... The Commission made no distinction between existing transmission capacity contracts that were associated with an associated power sale and those that were not.

... We also held that reserved but unused capacity should not revert to the transmission utility to be resold on a firm basis; instead, it could be scheduled and resold by the transmission-owning utility only to the extent that the holder of the transmission rights was not utilizing them. FERC's extensive discussion of the effect that its new transmission agreements without an associated power sale contracts differently than those associated with such sales agreements. ... Arguments that FERC should grandfather only agreements with associated power sales were put forward in at least one court case involving Order No. 888 and they did not prevail.

... We ultimately decided that the Commission's goals of competitive and non-discriminatory markets could co-exist with various kinds of prior but ongoing arrangements, and that would not be necessary to interfere with the terms of negotiated agreements. [Order no. 888 at 31,664-31,665]. When FERC advanced its plans for competitive wholesale power markets in Order No. 2000, it again concluded that abrogation of existing transmission contracts continues to be unnecessary. [Order No. 2000 at 31,204]. At that time the Commission noted: 'We recognize that existing contracts represent negotiated rights and obligations achieved through mutual negotiation.' [Order No. 2000 at 31,205.]

Q13. Was the Commission ever concerned that existing contracts for transmission capacity might in some cases 'lock up' so much capacity as to impede competition?

Of course it was concerned. The Commission recognized in Order No. 888 that hoarding or other anti-competitive practices could require it to reform some existing agreements. However, the Commission found no reason to limit the amount of transmission capacity to which a previous transmission customer was entitled in the absence of specific evidence of anti-competitive conduct. [Order No. 888 at 31,693.]

Q14. What were some of the safeguards that Order No. 888 included which ensured open access without the need to void existing arrangements?

In Order NO. 888, the Commission designed the structure of the OATT to provide market incentives for efficient use of transmission capacity. In the Commission's view, a customer that is charged for all fixed costs associated with reserved capacity would be far less likely to acquire or accumulate capacity rights that it did not need. The open access rules thus made it economically inefficient for a customer to hold capacity without putting it to use. More importantly, the OATT permitted any transmission-owning utility to schedule and sell to anyone eligible to buy unused capacity, any capacity that a holder of firm transmission rights did not schedule. [Order 888 at 31,693.]

... Q16 Do the capacity reservations of NB Power Generation into New England through the MEPCO tie constitute the type of negotiated agreement that would have been grandfathered as an existing contract under Order NO. 888?

Yes, I believe so. ... NB Generation purchased the transmission capacity only after processes that allowed other potential users to bid for those rights.

... My understanding is that, with respect to both the 470 MW and the 200 MW of capacity that were posted on NB Power's OASIS, interested entities had constructive notice that any prior agreements were ending by their own terms and they were free to bid competitively with NB Power for uncommitted capacity.<sup>67</sup>

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<sup>67</sup> Evidence of James Hoecker, former Chairman of FERC. Evidence filed September 29. NB PUB hearing to review Section 2.1 of NB Power's Open Access Transmission Tariff.

## Literature Review – Part 3

### Cost Allocation Principles – Open Access Transmission Tariff

Very recently, the New Brunswick Board of Commissioners of Public Utilities approved an Open Access Transmission Tariff (OATT) for NB Power on June 19, 2003. It had an effective date of September 30, 2003, at which time electricity supplier choice was made available for municipal wholesale and industrial customers served from NB Power's transmission system (69 kV and above).

The rate making principles underlying the NB Power OATT are based substantially on FERC guidelines as can be seen from the following excerpts from Section 2 of a June 2002 background paper entitled *NB Power Transmission Tariff Design*.

#### “2.0 TRANSMISSION RATE MAKING PRINCIPLES...

##### 2.1 Evolution of Principles Applicable to NB Power

Rate making principles for electric transmission services have been developed only in the last decade. They have been driven mainly in North America by the FERC which is empowered to regulate the American Federal Power Act (FPA). Amendments to the FPA in 1992 provided for competition in electricity supply at the wholesale level, where wholesale is defined as “purchase for resale”. Since then the FERC has significantly influenced transmission tariff design...

While the FERC has no jurisdiction in New Brunswick, its principles have influenced policy makers here. The New Brunswick Market Design Committee has reviewed transmission tariff issues as part of its work regarding the implementation of supplier choice in New Brunswick. ...

##### 2.2 FERC Transmission Pricing Policy

... The *Transmission Pricing Policy Statement*, issued by the FERC on October 26, 1994, specifies five principles regarding the pricing of transmission services.

... The FERC states that the pricing of transmission “be just and reasonable and not unduly discriminatory or preferential”. The Commission elected to permit more flexibility to utilities to file innovative pricing proposals that meet the traditional revenue requirement but only if they satisfy the pricing principles below:

- **Transmission Pricing Must Meet the Traditional Revenue Requirement**  
*‘First a utility must determine its total company revenue requirement, the capital component of which traditionally has been measured by embedded (depreciated original) cost. Second, a utility must allocate among individual customers or classes of customers that portion of the total revenue requirement that is attributable to providing transmission services, in a manner which appropriately reflects the costs of providing transmission service to such customers or classes of customers. Finally the utility must design rates to recover those allocated costs from each customer class. Different customers may pay different rates if they use the system in different ways.’*
- **Transmission Pricing Must Reflect Comparability**  
*This principle requires that an ‘...open access tariff that is not unduly discriminatory or anti-competitive should offer third parties access on the same or comparable bases, and under the same or comparable terms and conditions, as the transmission provider’s uses of its system.’*

- **Transmission Pricing Should Promote Economic Efficiency**  
The FERC specifies that transmission pricing should promote; *'...efficient expansions of transmission capacity; efficient location of new generators and new loads; efficient use of existing transmission facilities..., and, efficient dispatch of existing generating resources'*.
- **Transmission Pricing Should Promote Fairness**  
*'As a general matter, transmission pricing should be fair and equitable'*. Current transmission customers should not pay for the cost of providing wholesale transmission services to third-parties nor should third-party customers subsidize existing customers. *'The major purpose of transmission pricing reform should be to provide more efficient price signals, particularly for new transmission uses, and not simply to reallocate sunk costs'*.
- **Transmission Pricing Should Be Practical**  
*'Transmission pricing should be practical and as easy to administer as appropriate given the other pricing principles'*.

... there now appears to be a preference for proposals that conformed to the first two principles. While the other three principles continue to be viewed as goals that a conforming proposal must strive to meet, achievement is balanced against the need for transmission rates that are 'just and reasonable'.

### 2.3 Order 888 Pro Forma Tariff

In 1996 the FERC issued Order 888 which, included the Pro Forma Tariff. The order required all utilities under FERC jurisdiction to file a tariff which specified the terms, conditions and a pricing methodology that conformed to the pricing principles. The FERC was still open to non-conforming pricing proposals, but required that the proponent demonstrate that it was superior to the Pro Forma approach. In addition, through Order 889 the FERC standardized the reservation process through which transmission services could be transacted. This includes the requirement for an Open Access Same-Time Information System (OASIS) and the Standards of Conduct with respect to non-discriminatory control of third party information. Clarifications to the Pro Forma approach have been made through various decisions and rulings of the FERC since.

#### 2.3.1 Pro Forma Transmission Services

Under the *Pro Forma Tariff* the transmission provider is responsible for providing reliable and efficient dispatch and transportation of energy (delivery service only). ...Network service is firm transmission service delivered to the high side of the substation transformer. ...The transmission provider will provide network integration transmission service on a comparable, non-discriminatory basis to network customers...

#### 2.3.2 Ancillary Services and Curtailments

The Pro Forma Tariff requires that the transmission provider make some ancillary services available at regulated rates. ...

#### 2.3.3 Postage Stamp Rate

A postage stamp rate for electricity transmission is one that does not vary according to the location of the buyer or the seller... The Pro Forma allocates a relevant revenue requirement to users based on their contribution to the transmission system peak load. The postage stamp rate is determined by dividing the relevant revenue requirement (\$/yr.) by the applicable peak load (kW) to get an annual rate (\$/kW/yr.). While the overall method is clear, there are significant issues regarding what constitutes a relevant revenue requirement for what type of service and what peak loads should be used.

### 2.3.4 Clarifications to Order 888

#### Kentucky Utilities Company Opinion and Order

...In the original FERC code of accounts generator step up transformers (GSUs) were classified as transmission assets and many utilities included the GSU costs in their original transmission tariff rates. '... we find a more accurate method of cost recovery is to directly assign the costs of each GSU transformer to the generator to which it is connected.

#### Court of Appeals (D.C.)

A number of utilities challenged the legal authority of FERC to issue Orders 888 and 889 and petitioned for its review. As recently as June 30th, 2000, subsequent to Order 2000 on Regional Transmission Organizations, the US Court of Appeals found in favour of the FERC as follows

'Open access is the essence of Orders 888 and 889. Under these orders, utilities must now provide access to their transmission lines to anyone purchasing or selling electricity in the interstate market on the same terms and conditions as they use their own lines. ... Finding few defects in the orders, we uphold them in nearly all aspects'.

### 2.3.5 Influence Outside the United States

Although the FERC has no direct jurisdiction outside the United States, it has had significant influence on the implementation and design of external tariffs. First, the FERC has instituted a reciprocity requirement on all non-jurisdictional utilities that use the tariffs of jurisdictional utilities. Second, non-jurisdictional companies wishing to sell electric power at market based prices in the U.S. must acquire a power marketing authority license from the FERC. Thirdly, the license requires that the reciprocal transmission access to be provided is done under a tariff that is equal to or superior to the Pro Forma. The effect of this latter point has led to the development and implementation of Pro Forma tariffs by utilities in Canada and Mexico. Today the Order 888 Pro Forma Tariff is the most commonly applied tariff in Canada as well as the United States.

### 2.4 Market Design Committee<sup>68</sup> Recommendations

As part of the preparation process for the implementation of this level of supplier competition, a multi-stakeholder Market Design Committee was formed to make recommendations to the Minister of Natural Resources and Energy regarding the market structure. A number of these recommendations concern the design and implementation of the transmission tariff.

'The MDC [Market Design Committee] recommends that the transmission system will provide open, equal non-discriminatory access to all eligible market participants under terms and conditions compatible with FERC Orders 888 and 889. The System Operator will have an Open Access Transmission (OATT) for network and point-to-point service covering transmission service: within the province, into the province, out of the province, and through the province The PUB shall approve the OATT.'

[MDC recommended charges be based on monthly net non-coincident peak demand.]

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<sup>68</sup> Established by the Minister of Natural Resources of New Brunswick to make recommendations concerning the design, structure, and rules for the development of a wholesale electricity market. The Final Report (April 2002) is available at [http://www.nbmdc-ccmnb.ca/final\\_report.asp](http://www.nbmdc-ccmnb.ca/final_report.asp)

### 3.0 TRANSMISSION SERVICES COST ALLOCATION AND RATE DESIGN

A transmission tariff defines the terms, conditions and price under which a user (transmission customer) can gain access to the transmission provider's infrastructure (transmission assets). ...this process is the same as that detailed in the first pricing principle of FERC. *'First a utility must determine its total company revenue requirement, ... Second, a utility must allocate ... the total revenue requirement ... in a manner which appropriately reflects the costs of providing transmission service ... Finally the utility must design rates to recover those allocated costs from each customer class.'*

#### 3.1 Transmission Revenue Requirement

The first step in designing an efficient and equitable transmission tariff is to determine the appropriate revenue requirement that must be recovered from the sale of services. .. This revenue requirement includes all costs (amortization costs, operation, maintenance and administration costs, finance charges, and payments in lieu of taxes) plus a regulated return on investment. This revenue requirement relates to all transmission assets ...

In addition to the costs of all transmission lines at voltages of 69 kV or higher and terminal stations between transmission lines, the revenue requirement includes the costs associated with the generation step up transformers of NB Power generators. Because some of these assets are not associated with the transmission services offered under the tariff it is necessary to break down the revenue requirement into component pieces for all assets. Only after such a breakdown is completed can costs be allocated to specific services.

Amortization costs are able to be linked directly to specific assets because the gross and net asset value of each asset is accounted for in the company's accounting records. OM&A is allocated to each asset based on gross asset value while interest, taxes and return are allocated based on net asset value.

#### 3.2 Cost Allocation Analysis

The purpose of the cost allocation analysis, which is the second major activity in the development of transmission rates, is to allocate the appropriate revenue requirement (i.e. the costs associated with transmission) to the appropriate services. The following steps are required to do this in a manner that is both efficient and equitable:

- Definition of the transmission services to be provided
- Definition of the basic functions of the transmission system
- Allocation of transmission revenue requirements to the different functional uses of the system
- Determination of system usage by service
- Allocation of the functional costs to the transmission services

##### 3.2.1 Services Defined in Tariff

The Tariff defines two transmission services that are consistent with the FERC *Pro Forma Tariff*; point-to-point and network service. In addition, the ancillary service of Scheduling, System Control, and Dispatch is an obligatory service that must be provided by the transmission provider and taken by the transmission customer. The rate design of these three services are considered here in Section 3...

Point-to-Point Service refers to the reservation of capacity for the transmission of energy from a Point of Receipt to a Point of Delivery. An example of this would be a reservation of 100 MW from the Nova Scotia interconnection to the Hydro Quebec interconnection. This service is available on either a firm or a non-firm basis. The primary points of receipt and/or delivery can also be changed on a non-firm basis to secondary points but only if there is sufficient transmission capacity available after all other uses of the system have been accommodated. In other words, when a firm reservation is used to deliver power

between secondary points of receipt or points of delivery, the service provided is subservient to all other uses of the grid, including non-firm point-to-point service. It is usually used for wholesale transactions between systems rather than for the direct supply of load within a system. However it is available for both uses at the discretion of the transmission customer.

Network Service is firm transmission service for the delivery of both capacity and energy to the high side of the substation transformer of the transmission customer. It is usually used for supply of load within the system. Network customers (large industrial and municipal customers) have the option of either owning their own substation transformer or renting this equipment from Customer Service. ...

Scheduling, System Control, and Dispatch Service is required to schedule the movement of power into, out of, through, or within a control area. Only the system operator of the control area in which the transmission facilities are located can provide this service.

Throughout North America most utilities have chosen not to provide voltage differentiated rates for unbundled transmission services. ... Where the FERC has jurisdiction, they have deemed that the entire transmission system operates as a single integrated piece of equipment and they have consistently mandated a fully rolled-in approach without voltage differentiation.

### 3.2.2 Transmission Functions

The services defined in the previous section use different parts of the transmission system. The purpose in this section is to identify which assets are used to provide which services. For the purposes of the NB Power Tariff, assets have been grouped into four main functional groups as follows:

- Generation Related Transmission Assets[GTRAs]
- Bulk Network Assets which can be further subdivided into: Interconnections  
In-Province network
- Local Service Assets
- Energy Control Centre Assets

### 3.2.3 Functional Allocation of Costs

For the NB Power Tariff, it is proposed that interconnections and local service lines be included with the bulk network because they have relatively low costs and they provide market opportunities to both loads and suppliers. As a result the functional costs are allocated as follows:

- All GRTAs including GSU costs and non-GSU costs are allocated as direct assignment charges to generators
- Interconnections, In-province Bulk Network and Local Service costs are the common use portion of the transmission system and are allocated as revenue requirement costs to be collected from transmission services under the tariff..
- Energy Control Centre costs are allocated to Scheduling, System Control and Dispatch and are to be collected through tariff rates for that service.

### 3.2.4 Determination of System Usage

Usage of the system by various services must be defined in order to allow the revenue requirement to be allocated to the services. The challenge with usage is to select metrics for each of the services such that the cost allocation meets the appropriate rate making principles. “Cost causation” and “used and useful” principles are the two most relevant to the issue of what usage to apply for the allocation of revenue requirements.

The allocation of the transmission revenue requirement in the NB Power cost allocation analysis to point-to-point and network services is based on the approach prescribed by the

FERC through Order 888. This allocation is based on the principle that the monthly coincident peak system load, or usage, is a fair measure upon which to allocate the revenue requirement of the transmission system. Coincidental peak load is defined as the sum of two or more peak loads that occur in the same time interval. The use of 12 monthly coincident peaks balances the “cost causation” and “used and useful” principles of transmission tariff rate making. Use of a single coincident peak on the New Brunswick system tends to increase the allocation of revenue requirement to network services and understates the usefulness of the system to point-to-point services.

The FERC approach is incorporated in Section 34.3 of the Pro Forma Tariff ... which states:

*The Transmission Provider's monthly Transmission System load is the Transmission Provider's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to Part II of this Tariff plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.*

### 3.2.5 Allocation of Revenue Requirements to Services

... As noted above, these are point-to-point service, network service and the Scheduling, System Control and Dispatch Service. ... The transmission provider also collects revenues for the provision of services in addition to long-term firm services. These include short-term firm and non-firm point-to-point services, a grandfathered wheeling contract that pre-dates open access, and power factor penalties. ... This revenue requirement is allocated to the different transmission services based on their load ratio share of the system.

## 3.2 Rate Design

Now that costs have been allocated to specific services it is possible to design rates to recover these costs. ... This design of rates involves the following:

- Selection of a rate structure
- Selection of billing determinants for each service
- Determination of rates using the billing determinants to collect the revenue requirements

All of the information determined previously from the Total Revenue Requirement and the Cost Allocation Analysis is considered.

### 3.3.1 Postage Stamp Rate Structure

A postage stamp rate for electricity transmission is one that does not vary according to the location of the buyer or the seller (point of delivery and point of receipt). ... Although the most common approach in North America has been to use postage stamp rates, alternative transmission service pricing structures have been identified and used in some jurisdictions.

The alternatives to a postage stamp rate include location based (zonal or nodal) pricing, flow-based rates, and distance based rates. NB Power's current approach is a postage stamp rate that is the structure applied in the FERC Order 888 Pro Forma Tariff. This approach was also adopted in Saskatchewan, Manitoba, and Quebec. British Columbia, Alberta and Ontario have opted for zonal rate approaches. Most U.S. utilities have implemented the Pro Forma postage stamp approach but there are cases where locational-based marginal pricing, ... zonal, ... flow gate, ... and distance based, ... been approved by FERC. ...

### 3.3.2 Definition of Billing Determinants

In order to determine the price that will be charged to users of a particular service the metric, also referred to as a billing determinant, must be defined. Some of the commonly used billing determinants in the electric power industry are customer charge, kW of demand, and kWh of energy.

In defining the billing determinant one must consider issues such as measurability, simplicity, and fairness. It has already been established in the discussion above on cost allocation that transmission costs should be allocated to users based on the committed capacity. In the case of long-term point-to-point customers, the reserved MWs define the committed capacity. Reserved quantity can readily be used as the billing determinant for point-to-point service. In the case of network customers committed capacity is more difficult to define but, as discussed in the cost allocation section, is a function of the 12 monthly coincident peak loads.

Energy delivered can be considered as a billing determinant for a network customer's transmission usage but this approach does not follow the principle of cost causation. A customer with a very low load factor (a low quantity of energy delivered relative to the peak demand) would pay very little for transmission even though the transmission system needs to be able to meet the customer's peak demand. Such an approach would clearly lead to cross subsidization for transmission services of low load factor customers by other customers.

...FERC Order 888 and subsequent jurisprudence clearly state that self-generating customers must be provided with the option to choose between point-to-point service and network service. ...In the *FERC Pro Forma*, if the customer chooses network service the billing determinant is the load ratio share based on the gross demand at the time of system peak, not the net demand. However, some utilities with self-generation have modified this to include only a percentage of the self-generation component of the load as a means of reaching a negotiated settlement of this issue.

Canadian Utilities implementing tariffs have tended to adhere to the *FERC Pro Forma* by billing for network service on the basis of coincident demand on gross load. It is worth noting that in these jurisdictions they have gone to the minimum Order 888 requirement of wholesale access but not to transmission level retail access as is being done in New Brunswick based on *the Energy Policy White Paper*.

...Based on all the factors discussed in this section net non-coincident demand by delivery point has been selected as the billing determinant for use in the NB Power Tariff design for network service. Reserved capacity has been selected as the billing determinant for point-to-point service.

### 3.3.3 Determination of Rates

Given that the revenue requirement and billing determinants have been defined for each service the nominal rate is merely the revenue requirement for the service divided by the respective billing determinant. ...

For transmission service it is a common industry practice in North America to apply what is frequently referred to as Appalachian pricing. In Appalachian pricing the short term services are priced higher for an equivalent time period. This concept has been approved by FERC and is used in Manitoba and Saskatchewan. This approach with minor modifications has also been applied in Quebec subject to the April 2002 decision of the Quebec regulator, the Régie de l'énergie.

The Appalachian pricing approach applied by NB Power is consistent with FERC requirements and defines various short term rates as a fraction of the yearly rate as follows:

Yearly = nominal rate    Monthly rate = Yearly rate /12    Weekly rate =Yearly rate /52

On-Peak Daily rate = Weekly rate /5                      Off - Peak Daily rate = Yearly rate /365

On-Peak Hourly rate =On-Peak Daily rate/16    Off-Peak Hourly rate =Yearly rate/8760

The rationale behind the On-Peak Daily and Hourly rates is that there is a difference between short-term services used for meeting peak load and those that are taking advantage

of economically profitable opportunities. On-Peak hours for point-to-point service are defined by NB Power as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday. These types of transactions tend to occur on-peak and therefore in order to fully recover the appropriate revenue requirement these services are often priced with the On-Peak Daily rate at the weekly rate divided by 5 and the On-Peak Hourly rate is the On-Peak Daily rate divided by 16. ...

#### 3.3.4 Power Factor Penalty in the Transmission Tariff

The tariff includes a power factor penalty that will be applied for any month in which a transmission customer taking network service has a power factor of less than 90%. ...<sup>69</sup>

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<sup>69</sup> NB Power Transmission Tariff Design. June 2002  
[http://www.nbpower.com/en/about/trans\\_dist/tar/appendixb-tar.pdf](http://www.nbpower.com/en/about/trans_dist/tar/appendixb-tar.pdf)

## Literature Review – Part 4

### **Jurisdiction Specific Information**

### **New England, Canada, and the Maritimes**

#### **The New England States**

Today, the New England States appear to lead the continent in terms of having an advanced market design, that most similarly follows what FERC might consider (left to its own discretion) to be most solidly based on the appropriate theories to encourage the most appropriate long term market behavior. This statement is not intended to take away from the well operating models of PJM (Pennsylvania, New Jersey, Maryland) or New York, but rather to underscore the theoretical alignment of New England with FERC.

The New England Conference of Public Utilities Commissioners, Inc., in a letter to the Chairman of FERC, dated March 26, 2003, applauding FERC's efforts in working towards a standard market design, suggested that New England's successes in applying regional sensitivities to national initiatives should be replicated elsewhere.

“We believe that as the Federal Energy Regulatory Commission prepares its final rules on Standard Market Design, it should look to the New England region as the template for what has to be common in all markets and what can be left to regional development. On March 1, 2003, New England implemented a new market design that includes the most important features of the Commission's proposed SMD, including a congestion management system based on locational marginal pricing, and a multi-settlement system. This new market design builds on the long commitment of the New England region to a coordinated power pool, non-discriminatory access to the transmission grid, and the reduction of seams between regions. However, New England still needs the flexibility accorded by the Commission to participate in the building of a market design that will cost effectively contribute to reliability, investment, fair cost sharing, and a stable, robust wholesale electric market that will benefit all citizens in New England. Such a market design must accommodate regional progress and respect the unique aspects of New England....

- New England has created NE-ISO, which has been a trail blazer in market development, particularly with SMD, and continues to forge new trails with the support of states and companies in the region. We remain convinced that the regional decision making process we are developing in New England, which builds on existing institutions and under which market participants will be given a meaningful opportunity for input but will play only an advisory role should be left undisturbed....

#### New England States call for some regional differences:

The Commission has stated that there are aspects of SMD that are best left to regional development, and New England respectfully suggests that, in large measure because our market is already in harmony with virtually all of the principles articulated in the Commission's SMD proposal, we have achieved the right balance between standard market rules and regional differences. While individual states have specific comments communicated through the rulemaking process, New England requests that the Commission adopt the following general recommendations and discuss them in the upcoming “White Paper.”

- Acknowledge that regional differences warrant regional approaches for some aspects of market design... The people and institutions of New England are more sensitive to the needs and priorities of New England and are more likely to find workable constructs, and on many issues federal involvement may only be necessary when agreement cannot be reached at the regional level.

- Acknowledge that many aspects of resource adequacy, transmission planning, and siting are regional and state jurisdictional issues, and should be dealt with in these forums, while allowing the development of expedited processes for resolving such issues, instituted regionally.
- Acknowledge that forcing New England to conform to a one-size-fits-all national market design and schedule may not be an improvement, and may actually reduce the value of the time, effort, and monetary investment of New England business, industry, and government in developing the New England wholesale market do not let the SMD NOPR be an anchor dragging on the progress that we have already made here in New England.

There is merit in developing a workable standard market design as our nation becomes ever more networked and dependent on unimpeded movement of energy. We applaud FERC for its continued efforts at framing the parameters of such a standard market design. We support a steady FERC hand in establishing broad principles governing standard market design, and in minimizing to the extent practical barriers to electric markets. But we reiterate the request we have consistently made that the Commission reward our New England initiative and commitment with an appropriate degree of flexibility, rather than restrain us for having taken on the job of creating a workable market in New England.”<sup>70</sup>

The New England States, with the exception of Vermont, have both wholesale and retail competition, and all customers may access the transmission system in order to acquire power from elsewhere. In Vermont, where there has not been electricity restructuring, FERC’s jurisdiction still applies for transmission access at the wholesale level, and municipal utilities are eligible to purchase power elsewhere and take delivery under the Open Access Transmission Tariff structure, (though retail customers are not eligible for open transmission access).

### Canadian Viewpoint of FERC Role in Domestic Transmission Matters

Canadian electric utilities understand both the complexity and the fragility of the North American power grid, as well as their interdependence with electric utilities in the United States. It goes beyond the Canadian utilities’ need to follow FERC policies in order to sell into the United States market. The utilities are fully aware that any improvements in the market rules that can be instituted now are vital to the stability and reliability of the grid and will help buy the time needed to construct new transmission facilities.

#### **Nationally**

The Minister of Natural Resources Canada, in a speech to the Toronto Board of Trade on September 6, 2001, indicated that Canada is not interested in assuming a form of policy subordination to the US. He stated that what Canada seeks is an expansion and successful functioning of North American energy markets. He noted that it is anticipated that Canada should expect important new electricity marketing opportunities in the United States which will be especially valuable in terms of the hydro-power potential in Newfoundland, Quebec, Manitoba and British Columbia. He noted the issue of reliability standards for the full electric power system is outstanding, that it has been a voluntary system, but the Americans

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<sup>70</sup> The New England Conference of Public Utilities Commissioners, Inc., letter to the Chairman of FERC, dated March 26, 2003.  
[http://www.necpuc.org/public\\_filings/document71.doc](http://www.necpuc.org/public_filings/document71.doc)

are now planning to enact mandatory standards. He also noted that FERC appears to be assuming a stronger role and is moving ahead on a new structure of Regional Transmission Organizations and that Canada needs to position itself, collectively, to defend and advance its common interests in dealing with U.S. inter-connections.

A National Energy Board news release dated January 23, 2003, stated:

“The structure of the North American transmission grid is being reshaped by the FERC RTO and Standard Market Design (SMD) initiatives. Many market participants believe that RTO development will promote trade by increasing access and lowering transmission costs.

Practically all provinces have expressed interest in some form of participation in RTOs. Manitoba has already concluded a coordination agreement with the Midwest Independent System Operator and B.C., New Brunswick and Nova Scotia have supported RTO membership. Québec, Ontario and Alberta are assessing their strategic options. Apart from the technical challenges posed by the implementation of SMD, or achieving operational compatibility with SMD, concerns in Canada have been raised with respect to regulatory sovereignty, RTO governance, and ensuring that the interests of Canadian consumers are not compromised.

Canadian entities have also identified the need for more transmission to the U.S. as a means to foster future trade. To improve access to U.S. markets, a number of new transmission projects have been proposed over the past two to three years. An innovative aspect of some of these proposals is that they would be merchant power lines, targeting specific export markets.”<sup>71</sup>

### **British Columbia**

In a May 2, 2002 presentation by the BC Ministry of Energy and Minerals to the Western Governors’ Association Workshop on North American Free Energy Trade, the role BC plays in US energy policy, with focus on electricity, was outlined as follows:

Powerex, BC’s export Crown Corporation, voluntarily agreed to be licensed by the federal government of the US. Powerex holds a FERC marketer’s certificate and BC Hydro agrees to operate as functionally separate - as any US utility. The British Columbia Utilities Commission (BCUC) has adopted FERC standards for wholesale transactions as their own and takes on the FERC role in BC.

... Being a foreign country/province we generally don’t have a voice in the decisions made by US federal government - that affect us. However, that does not keep us from being active participants in the US federal processes.

- We intervene and participate in FERC dockets
- We participate in the FERC rule makings, and
- We have worked on federal legislation back in Washington DC – a two pronged approach that involved a federal-provincial process through Ottawa and the Canadian Ambassador in Washington DC; and through our membership and association with WIEB and CREPC (14 years!)
- We participate in government to government dialogues and discussions...
- We participate in industry to industry standard setting...

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<sup>71</sup> National Energy Board News Release, January 23, 2003.

Transmission and Regional Transmission Organizations, Backgrounder  
[http://www.one-neb.gc.ca/newsroom/releases/2003/nr0305\\_e.htm](http://www.one-neb.gc.ca/newsroom/releases/2003/nr0305_e.htm)

We are willing to go so far as putting our transmission system under the control of an independent operator as part of RTO West and are working in BC to figure out how to make this work while maintaining our political sovereignty.

We have learned that if you participate you can influence. We have created innovative organizations that allow for fair participation on an international basis. It takes a long time and a lot of resources, and is often frustrating, but can be very productive and rewarding.<sup>72</sup>

## **Ontario**

Comments made by the President and CEO of the Ontario Independent Electricity Market Operator (IMO) at a Massachusetts Electricity Restructuring Roundtable on March 15, 2002, included the following:

“When it comes to the long term future of the North American electricity market, be it from the perspective of trade or reliability and mutual support, you are either in or you are out and the rules and standards that will determine this are being developed now. ...

The world is changing – and new rules are being developed. We cannot sit back and take as a given that in Ontario we will continue to have the influence that we have had in the past to ensure that international rules will be developed in our interests. This will only occur if we are active in showing leadership and participating in this domain. What is most important is not the existence, size or number of RTOs. What’s important is consistency of rules that allow the ability to take advantage of available resources, reduce pancaking of transmission charges and drive down costs.

It is important that we maintain an involvement in the evolution of the electricity marketplace structure to ensure that we can take care of Ontario’s interests, not only in the near term but also over the longer term. ...

This is why I think it important for us in Ontario to participate in FERC’s hearings into the RTO future in the U.S. and in examining what are the necessary features for an effective and efficient marketplace. It is why we see it as critical that we sit at the table with New York and New England to work on the rule development in the Northeast. ...

As the rules change, we are not just looking at the compatible needs of future markets for the sake of reliability, quality and cost optimization. We are all looking to ensure that we don’t lose the benefits that have been available and used time after time.

... I believe that we can be an effective party to the development of regional and international rules and standards in the new competitive regime. We do not have to adopt identical rules. In Ontario, as elsewhere, I expect that there will be good rationale to support bcal variations in rules. We are not, and will not, become FERC jurisdictional. I do however believe that rules that eliminate artificial barriers and facilitate mutual support will be in the best interests of all...<sup>73</sup>

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<sup>72</sup> British Columbia’s Participation in U.S. Electricity Policy – May 2, 2002 Presented By, BC Ministry of Energy and Minerals to Western Governors’ Association Workshop on North American Free Energy Trade. This is a shortened version of what appears in quotations in the Literature Review section of the report. <http://www.westgov.org/wieb/meetings/boardsprg2002/briefing%20materials/energy%20trade/bc&us.htm>

<sup>73</sup> CONSISTENT RULES – IS THERE AN OPTION?

Massachusetts Electricity Restructuring Roundtable Presented by: Dave Goulding, President and CEO, Ontario Independent Electricity Market Operator [March 15, 2002]  
[http://www.raabassociates.org/Articles/Roundtable\\_Goulding\\_3-15-02.doc](http://www.raabassociates.org/Articles/Roundtable_Goulding_3-15-02.doc)

## **Nova Scotia**

The Nova Scotia Electricity Marketplace Governance Committee (EGMC), established in 2002, reported to the Minister of Energy and had a mandate “to seek input from a broad range of stakeholders [and] to develop detailed recommendations regarding the subsequent implementation of the specific electricity restructuring measures announced in the energy strategy”.<sup>74</sup> The recommendations are to be used by the Energy Minister to implement changes to legislation, regulations and government policy, with the objective to introduce limited electricity competition in Nova Scotia by 2005.

In October of 2003, the Committee released its Final Report. Chapter 6 of the report addressed transmission issues and stated the following:

“Giving Nova Scotia customers transmission access requires a major change in pricing electricity service. Nova Scotia rates are now bundled, which means that the customer buys electricity, ancillary services, and transmission and distribution services for one inclusive price. To allow transmission access, transmission prices must be separately identified under a transmission tariff. With the transmission tariff unbundled, generation rates must also be separately identified.”<sup>75</sup>

Recommendations contained in the EGMC Final Report, regarding transmission access and tariff design, are set out below: (Numbers shown indicate the recommendation number as indexed in the EGMC Final Report. Direct quotes are in italics.)

### **Price Unbundling**

- #15 *That, Nova Scotia Power Inc. (NSPI) develop and file a transmission tariff.*
- #16 *That any transmission tariff developed for use in Nova Scotia ensure open and non-discriminatory transmission access for all market participants.*
- #17 *The development of a transmission tariff for Nova Scotia that should initially include a scheduling and information system that need not be an Open Access Same-Time Information System (OASIS).*
- #18 *That, transmission tariffs in Nova Scotia develop towards eventual FERC compatibility.*
- #19 *That, when an OASIS is required to facilitate the reservation of firm and non-firm transmission, together with the associated functions of publication, scheduling, etc., the transmission provider seek ways to minimize its cost, including purchasing OASIS service from another jurisdiction which supports an OASIS.*

### **Services to be offered**

- #20 *Transmission services that are to be offered under the transmission tariff should initially include:*
  - *Network Integration Service for the delivery of both capacity and energy for the supply of load located within the Nova Scotia control area*
  - *Point-to-Point service for the reservation of transmission capacity from a specific point of receipt to a specific point of delivery for transactions involving imports into or exports from Nova Scotia. (Point-to-Point service would be offered on both a firm and non-firm basis).*

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<sup>74</sup> Nova Scotia Electricity Marketplace Governance Committee Final Report, October 2003. Appendix A, Terms of Reference. <http://www.gov.ns.ca/energy/documents/EMGCFinalReport.pdf>

<sup>75</sup> Nova Scotia Electricity Marketplace Governance Committee Final Report, October 2003. Chapter 6, Transmission Issues. Pages 37-56.

- #21 *That the transmission provider acquire ancillary services from market participants at least cost possible, including by competitive contract processes.*
- #22 *That the transmission provider offer an energy imbalance service based on costs, as approved by the Nova Scotia Utility and Review Board (UARB).*
- #23 *That the transmission tariff require the system operator to offer each of the following ancillary services:*
- |   |  |
|---|--|
| <i>Scheduling, control and dispatch</i>     | <i>Reactive supply and voltage control</i>         |
| <i>Energy imbalance</i>                     | <i>Regulation &amp; frequency response service</i> |
| <i>Operating reserve – spinning reserve</i> | <i>Operating Reserve – supplemental</i>            |
- #24 *That NSPI should give consideration to simplification in its tariff development, including point to point service and self supply of ancillary services.*
- #25 *That NSPI should consult with stakeholders in the consideration of tariff simplification.*

**Transmission Tariff Design and Rate Issues**

- #26 *Use of the following principles to determine whether the costs of transmission facilities should be included in the transmission tariff:*
- *The cost of a transmission facility used solely by one party should be assigned or charged to that party*
  - *The cost of transmission facilities that are not part of the transmission backbone should be directly assigned or charged to those parties that use them. The preferred alternative for realizing this objective is:*
    - *Costs for radial lines serving generators be assigned to those generators*
    - *Costs for generation step-up transformers be assigned to those generators*
    - *Costs for radial lines serving distribution loads be assigned to distribution, the revenue requirement to be recovered uniformly from all distribution level customers, supplied by both NSPI and the municipal utilities.*
- #27 *That transmission revenue requirements be allocated based on the average twelve monthly coincident peaks.*
- #28 *That the billing determinants to establish transmission charges for network customers be monthly net non-coincident peak demand and that for point-to-point customers it should be reserved capacity (estimated on a net load basis, if necessary.) The charge basis for existing self-generation customers would be hourly net non-coincident peak.*
- #29 *That the transmission tariff rate design be based on a consistent charge regardless of the location of the connecting customer, and that in addition new transmission customers be assessed locational factors relating to transmission losses, which may be negative or positive.*

**Congestion Management**

- #30 *That all existing customers share the congestion costs on the existing system.*
- #31 *That new generators and major loads be required to pay:*
- *All costs to connect to the transmission network.*
  - *All costs of system upgrades required to mitigate congestion costs that they would otherwise create. Generators who agree to be constrained down if this alleviates the congestion to a level consistent with what previously existed will not be charged for additional congestion costs.*

- *Any direct transmission system benefits from the investments charged to the generator or load (e.g., reduced losses or reduced congestion costs that are borne by other parties) will be credited to the generator or load.*
- *Any direct benefits or costs due to the impact of the new generation or load on total system losses will be paid or charged to the new generation or load.*
- *The generator will be responsible only for the cost of advancing construction facility upgrades if the transmission service provider has previously identified them as required for reliability purposes.*

#32 *That existing firm load customers within Nova Scotia be entitled under the open access tariff to firm Network Service, and that they have renewal rights to such service.*

### **Transmission Rights**

#33 *That Nova Scotia maintain a system of import and export transmission rights for electricity and capacity.*

### **System Operator Functions**

#34 *That the transmission function within NSPI be given the role and responsibilities of a Transmission Provider, including:*

- *Create and file a transmission tariff*
- *Provide transmission service under the transmission tariff*
- *Provide ancillary services under the transmission tariff*
- *Operate the transmission system in accordance with the transmission tariff*
- *Be responsible for the safe and reliable operation of the electricity supply system in Nova Scotia*
- *Schedule transaction on the interconnections between Nova Scotia and neighboring jurisdictions.*

### **Metering Standards**

#35 *That, as metering installations at transmission interfaces with generation, distribution or large customers are replaced or resealed, they should be upgraded or replaced by revenue quality interval meters.*

### **Summary**

Recommendations of the EGMC Final Report include the following:

#### Price Unbundling

It recommended that Nova Scotia Power Inc. (NSPI) develop and file a transmission tariff that would ensure open and non-discriminatory transmission access for all market participants. The tariff should be developed in an evolutionary manner and initially include a scheduling and information system that need not be an open access same-time information system (OASIS) as defined by FERC in Order 889. The tariff could eventually evolve toward FERC compatibility, and at such time it is determined an OASIS is required, ways to minimize cost should be considered including the purchase of OASIS service from another jurisdiction.

#### Services Offered

It recommended that the tariff should provide for Network Integration Service for the delivery of both capacity and energy for the supply of load located within the Nova Scotia Control area, and Point-to-Point service for the reservation of transmission capacity for imports into and exports from Nova Scotia. Ancillary services offered by the system operator and included in the transmission tariff should include: (1) scheduling, control and

dispatch, (2) reactive supply and voltage control (3) energy imbalance service based on costs, (4) regulation and frequency response service, (5) operating reserve – spinning reserve, and (6) operating reserve – supplemental.

#### Tariff Design

It recommended that customers should pay for transmission services on the basis of cost causation, with demand charges allocated based on the average twelve monthly coincident peaks. It is recommended that the billing determinants be *monthly non-coincident peak*, for network customers, *reserved capacity* for point-to-point customers and *hourly net non-coincident peak* for self-generation customers. The EMGC recommended a consistent charge regardless of location (i.e. a postage stamp rate).

#### Congestion Costs and Transmission Rights

It recommended that existing customers share the congestion costs on the existing system while new generation and new loads would pay for incremental congestion caused by such additions. Consistent with the FERC pro forma tariff, existing firm load customers within Nova Scotia should be entitled to firm network service and have renewal rights to such service, and Nova Scotia should maintain a system of import and export transmission rights for electricity and capacity.

#### System Operator Functions and Metering

It recommended that NSPI be given the role and responsibilities of a transmission provider. And it recommended that as meters are replaced or resealed at transmission interfaces with generation, distribution or large customers, that they should be upgraded to revenue quality interval meters.