UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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TransÉnergie U.S. Ltd. ) Docket No. ER00-____-000

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CROSS SOUND CABLE INTERCONNECTOR
RATIONALE IN SUPPORT OF LOCATION DIFFERENTIAL PRICING

JOINT DIRECT TESTIMONY OF
RAYMOND L. COXE
AND
JOSÉ A. ROTGER
ON BEHALF OF TRANSÉNERGIE U.S. LTD.
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1 I. QUALIFICATIONS

2 Q. Mr. Coxe, please state your name, title, and business address.

3 A. My name is Raymond L. Coxe and my business address is 110 Turnpike Road, Suite 300, Westborough, Massachusetts 01581. I am the Vice President for Transmission Marketing for TransÉnergie U.S. Ltd.

7 Q. Please describe TransÉnergie U.S. Ltd. (“TEUS”).

8 A. TEUS is the U.S. transmission project development subsidiary of TransÉnergie, the transmission division of Hydro-Québec. Hydro-Québec, a Crown corporation, is a utility with generation and transmission facilities in the province of Québec, Canada. Hydro-Québec’s functionally separate transmission facilities are vested in
TransÉnergie which, pursuant to a strict code of conduct, independently manages and operates Hydro-Québec’s extensive high voltage transmission system. All of TransÉnergie’s business units are fully and exclusively dedicated to transmission projects and businesses.

Q. Please describe your educational background and training.
A. I received undergraduate and doctoral degrees in nuclear engineering from the Massachusetts Institute of Technology in 1982 and 1988, respectively. My doctoral research focused on electric utility system planning and optimization, and commercial design goals for new nuclear power plant concepts.

Q. Please summarize your professional experience.
A. Since May 1998, I have been Vice President of Transmission Marketing for TEUS, with responsibility for marketing the transmission capacity from TEUS projects, for developing new transmission products and services, and for advocating new structures for transmission system development in the U.S. and Australia. I am also responsible for transmission project development, transmission asset acquisition and evaluation of new business opportunities.

I co-authored a chapter entitled “System Planning under Competition” in the graduate textbook POWER SYSTEMS RESTRUCTURING: Engineering and Economics (M. Ilic, F. Galiana, and L. Fink (editors), Kluwer Academic Publishers, 1998). This chapter discusses the commercial planning of generation and transmission under
competitive market conditions, and outlines a framework for introducing efficient
competition into the transmission sector of competitive electricity markets.

Before joining TEUS in 1998, I worked for ten years at the New England Electric
System (“NEES”) Companies in several areas. Most recently, I was a Consulting
Engineer in the transmission project development unit at the NEES Companies,
responsible for reviewing and analyzing international electricity markets. Prior to
joining the transmission development unit, I worked in the Generation Marketing
group of the NEES Companies, where I had responsibility for long-term wholesale
power sales by New England Power Company. I continuously monitored the New
England wholesale electric power market, including the process and outcome of
numerous solicitations for unbundled generation services. I also participated in the
restructuring of the capacity, energy, transmission and ancillary services markets in
the New England Power Pool (“NEPOOL”).

Prior to joining the Generation Marketing group, I was an engineer in the Planning
and Power Supply Department of the NEES Companies. I worked on a variety of
power supply and system planning tasks, including economic analyses of proposed
power supply projects, calculation of system marginal costs, review of the capacity,
energy and ancillary service obligations of the NEES Companies under the NEPOOL
Agreement, and participation in the company-wide integrated resource planning
process.

Q. Have you previously testified before any regulatory commissions?
A. Yes. I testified before the Federal Energy Regulatory Commission in *NEES Transmission Services, Inc.*, et al., Docket No. ER96-1309-000. My testimony in that docket described the ancillary service provisions of the comparable service tariffs being filed for the transmission subsidiary being proposed by the NEES Companies in response to Order No. 888.

Q. Mr. Rotger, please state your name, title, and business address.

A. My name is José A. Rotger and my business address is 110 Turnpike Road, Suite 300, Westborough, Massachusetts 01581. I am the Manager for Regulatory Strategy for TransÉnergie U.S. Ltd.

Q. Please describe your educational background and training.

A. I received a Bachelor of Arts degree in Economics from Brown University and a Masters in Business Administration from Northeastern University.

Q. Please summarize your professional experience.

A. Prior to joining TEUS in early 1999, I was a Principal Rate Analyst in the Rate Department of New England Power Service Company (“NEPSCo”), the service company of the New England Electric System (“NEES”). During my five years at NEPSCo, I participated extensively in the NEES Companies’ restructuring and divestiture efforts, in addition to conducting a variety of cost of service and rate design analyses for several NEES companies. For two years prior to my departure, I
was responsible for all non-transmission-related rate filings of the NEES companies before the Federal Energy Regulatory Commission ("Commission").

Prior to joining NEPSCo, I was a Research Associate in the energy group of the Tellus Institute, where I was responsible for analyses of gas and electric utility cost allocation, rate design, cost of capital, demand side management cost recovery, and integrated resource planning regulations. Prior to that I served for over four years as an Economist with the Gas Division of the Massachusetts Department of Public Utilities ("MDPU") (now the Department of Telecommunications and Energy), where I was involved in all aspects of gas utility rate cases and resource planning filings. Prior to my tenure at the MDPU, I was a Staff Accountant with Peat Marwick Main & Co.

Q. Have you previously testified before any regulatory commissions?
A. Yes, I have previously testified before the New Hampshire Public Utilities Commission, the Pennsylvania Public Utilities Commission, the Rhode Island Public Utilities Commission, and the Massachusetts Department of Telecommunications and Energy.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?
A. The purpose of our testimony is to support TEUS’ application for authority to charge rates based on expected location differentials ("Location-Differential Rates") for
transmission service over its Cross Sound Cable interconnection project (the “CSC Interconnector”). In particular, our testimony will demonstrate how the CSC Interconnector and our request for Location-Differential Rate authority is fully consistent with the vision of competitive markets espoused by the Commission. Our testimony will discuss how the CSC Interconnector is an example of the type of market-driven transmission investment that could result from and facilitate the creation of efficient, competitive electricity markets, as described in Professor William Hogan’s paper on this subject (included in this filing as Exhibit 4). We will describe how these types of electricity markets (approved by the Commission in the mid-Atlantic, New York and New England regions of the US) will provide a clear, market-driven basis for valuation of incremental transmission capacity. We then discuss how the CSC Interconnector will operate in tandem with the market structures in New York and New England. Next, we suggest a framework for the Commission’s analysis of our request, including suggested analytical criteria for determining the appropriateness of allowing market-driven rates for merchant transmission projects and distinguishing such projects from other transmission investments. Finally, we describe TEUS proposed transmission tariff for the CSC Interconnector (included in this filing as Exhibit 5) which we believe is consistent with the Commission's emerging policies for encouraging competition, as articulated in Order No. 888 and the RTO NOPR.

III. OVERVIEW OF CSC INTERCONNECTOR PROJECT

Q. Please provide a brief overview of the CSC Interconnector.
A. The CSC Interconnector is a high voltage, direct current (“HVDC”) submarine cable system that will interconnect the electric transmission grids of New England and Long Island, New York. The CSC Interconnector will provide a power transfer capability of up to 600 megawatts (“MW”) of capacity and energy between Connecticut and Long Island, New York, in either direction. A more detailed technical description of the project facilities is included in Exhibit 1 of the filing. Exhibit 2 shows the proposed interconnection points on Long Island and in New England, and the route of the submarine cable.

The planned in-service date for the project (May 2002) has been developed through discussions with the Long Island Power Authority (“LIPA”) and other possible customers of the project. This date for commercial operation requires that binding financial commitments for the project be completed within the next few months so that construction can commence by the fourth quarter of 2000. Obviously, Commission approval of the regulatory structure for the project is a key component for the project’s financing. Hence, TEUS has filed this request for tariff approval well in advance the commencement of service for the project and respectfully requests waiver of the Commission’s 120-day notice requirement, 18 CFR § 35.3(b), as discussed in our Petition accompanying this filing.

Q. Please summarize the technical characteristics of the CSC Interconnector.

A. By virtue of its HVDC technology, the CSC Interconnector will provide a fully-controllable electric transmission link between Connecticut and Long Island. The
HVDC technology allows power flows over the facilities to be directly controlled in a manner not possible over a conventional, free-flowing alternating current (“AC”) transmission line. Thus, parallel, loop or unintended flows during normal operation do not arise with respect to the physical dispatch of the CSC Interconnector. Simply put, the CSC Interconnector will behave as if it were an “electricity pipeline” with “valves” which can directly control the level and amount of flows and, if desired, shut them off entirely. As discussed later, this ability to directly control the physical flow of energy between the two control areas in New York and New England simplifies the creation of tradeable transmission rights – initially defined as rights to schedule energy flows across the project between New England and Long Island. The CSC Interconnector will readily permit creation of tradeable “Interregional Scheduling Rights” that can be valued by competitive market processes and thus sold at rates set by those processes.

Q. Please summarize the commercial characteristics of the CSC Interconnector.

A. The CSC Interconnector will be a merchant transmission project, in the sense that the debt and equity investors in the facility will not have access to guaranteed revenues from the mandatory grid access charges in New York and New England. Unlike almost all other transmission investments in the United States, the owners of the CSC Interconnector will not include the project’s annual costs in any transmission revenue requirements recovered from captive ratepayers through a mandatory access charge. Thus, the project’s investors will (and must) rely solely upon sales of transmission capacity to willing buyers of the Interregional Scheduling Rights created by the
project to recover the project’s costs and earn any return that may be made on their investment. No users of the transmission grids in either New York or New England will be required to financially support the project except insofar as they voluntarily elect to purchase Interregional Scheduling Rights associated with the project. Thus, all of the market risks of the project (and the associated stranded cost risks) lie with the project’s owners.

Q. How will the CSC Interconnector be operated?
A. The CSC Interconnector will provide an additional intertie between the two presently discrete control areas and electricity markets in New England and New York. These two markets are currently administered by separate Independent System Operators (“ISOs”) – the New York Independent System Operator (“NY ISO”) and Independent System Operator – New England (“ISO-NE”). Each of these two ISOs dispatches the generation and loads within its own control area, and schedules physical energy interchanges with neighboring control areas (including each other) in accordance with its scheduling procedures and with transmission reservations made by grid users. Each ISO balances load and generation on its respective system to maintain the scheduled physical interchange of energy between the two regions (and with other neighboring control areas).

As with any energy interchanges between North American Electric Reliability Council (“NERC”) member regions, energy flows between the New York and New England control areas are scheduled by market participants in accordance with their
transmission rights on the applicable interties. These scheduled energy flows are subject to the “Transmission Loading Relief” (“TLR”) procedures in the event that a planned interchange would otherwise affect reliability in these regions.

Working together with TEUS (the operator of the CSC Interconnector), these two ISOs will coordinate the operation of the CSC Interconnector in a manner similar to the scheduling of energy flows over existing interties between the two control areas. Proposed schedules for energy flows over the CSC Interconnector will be submitted to TEUS by the shippers who have purchased Interregional Scheduling Rights on the project. Any unreserved Interregional Scheduling Rights and any Interregional Scheduling Rights that had been reserved but not scheduled will be posted on the Open Access Same-Time Information System (“OASIS”) operated by TEUS for the CSC Interconnector.

Once the market participants have made their final reservations and proposed their scheduled interchanges over the CSC Interconnector, TEUS will then reconcile the proposed schedules to develop a master “CSC Net Interchange Schedule.” This schedule will then be submitted to the New York and New England ISOs. The two ISOs will then coordinate the CSC Net Interchange Schedule with their internal dispatch schedules, their other interchange schedules (including the scheduled interchanges over the other ties between New York and New England), and all operational limits within either ISO. If constraints within or between the ISOs require modification to the CSC Net Interchange Schedule to maintain reliability within...
either the New York or New England control area, the ISOs (or their NERC TLR
agent) would invoke the applicable TLR procedures to modify the CSC Net
Interchange Schedule. The final CSC Net Interchange Schedule will then be
implemented by TEUS in coordination with the ISOs.

We note that the Direct Current (“DC”) technology used in the CSC Interconnector
allows close coordination among TEUS, the NY ISO and ISO-NE, while preserving
the tradeable transmission rights created by the project. The energy flows scheduled
in the final CSC Net Interchange Schedule (and only those energy flows) will
physically occur. Thus, the ultimate dispatch of the CSC Interconnector will be
controlled by the coordinated efforts of TEUS and the ISOs and will be subject to the
applicable reliability criteria of NERC and its northeast regional council, the
Northeast Power Coordinating Council (“NPCC”).

As the regional electricity markets in New England and New York mature, closer
coordination between these two ISOs may occur. Such increased coordination could
eventually lead to additional scheduling flexibility for the ISOs, with a commensurate
opportunity to exchange the Interregional Scheduling Rights for the more flexible
financial transmission rights being implemented with each ISO. Since the timing of
any such evolution of the New York and New England electricity markets is difficult
to predict, TEUS has developed an initial project structure that provides project users
with tradeable Interregional Scheduling Rights. This structure can readily be
converted to accommodate financial transmission rights should the conditions for such conversion occur.

Q. How will Interregional Scheduling Rights for the CSC Interconnector initially be made available to participants in the New York and New England electricity markets?

A. TEUS will conduct an open season process to help determine the ultimate size of the project’s facilities. Using the expressions of interest received during the open season process, TEUS will initially allocate Interregional Scheduling Rights on the project among the successful respondents to the open season. These successful respondents (the “Project Shippers”) will ultimately acquire Interregional Scheduling Rights in amounts and duration determined by the contractual commitments negotiated and executed during the open season process.

Q. What form of transmission rights will be initially sold by TEUS in the open season process and how do these rights compare to financial transmission rights?

A. Initially, the transmission rights offered by TEUS will be the Interregional Scheduling Rights described herein, instead of the financial transmission rights described in Professor Hogan’s paper and used within both the NY ISO and ISO-NE. Presently, the ISOs in New York and New England separately commit and dispatch the generation and transmission within their control areas. Hence, commercial transactions between the two control areas are realized as physical interchanges of energy over the existing interties.
Since the CSC Interconnector will be scheduled and dispatched in a manner similar to the schedule and dispatch of existing interties, we anticipate that the transmission rights on the project will initially be the physical Interregional Scheduling Rights rather than the financial transmission rights that are used within each ISO. However, as Professor Hogan notes in Exhibit 4, further coordination between these two markets would allow the dispatches across both regions to be coordinated so as to reach equilibrium prices throughout the combined region. This improved coordination would imply that interregional congestion would be valued on an interregional basis, and that the market-clearing locational prices throughout the wider region would be consistent across both New York and New England. If locational prices across the combined New York/New England region were consistently determined through an economic dispatch that is coordinated across both regions, financial transmission rights could function efficiently between the two markets. The interregional settlement surplus arising from coordinated interregional trade would ensure that those parties holding the interregional financial transmission rights would receive their full value.

Under those yet-to-be attained conditions for New York and New England, the transmission rights associated with the CSC Interconnector could be defined as the incremental financial transmission rights created between the applicable nodes in Connecticut and Long Island. These financial rights associated with the CSC Interconnector would be the only property rights that would be required for the project. Parties holding these rights would be entitled to receive a share of the
congestion rentals between the applicable nodes on Long Island and New England and could thereby achieve *ex ante* price certainty against any congestion costs between those nodes.

Additional flexibility would result from the fact that parties holding these financial rights could not preclude others from physically utilizing the CSC Interconnector. Parties without such rights could still engage in transactions whose flows crossed the CSC Interconnector, and such flows would be subject to the congestion charges determined by the locational prices at each connection point. The congestion rentals would be credited to those parties who held the financial rights, and such rights would be easily tradeable in a robust secondary market.

In all of the financial rights sales mechanisms approved by the Commission, market forces determine the prices at which these rights are traded. The ability to buy and sell such rights at Location-Differential Rates is fundamental to the efficient electricity markets enabled by CSC Interconnector. For the same reason that the Commission has accepted such market mechanisms to value transmission rights in the Pennsylvania-New Jersey-Maryland Interconnection (“PJM”) and NY ISO, we believe that TEUS’ request for authority to sell the Interregional Scheduling Rights over the CSC Interconnector at Location-Differential Rates is reasonable.

As the electricity markets in New York and New England continue to mature, the two ISOs may develop fully compatible locational prices and financial transmission
rights. Such an evolution would allow the Interregional Scheduling Rights to potentially be replaced with equivalent financial congestion rights. At such a time, TEUS would explore with Project Shippers possible amendments to the transmission agreements for the project to reflect such changes in these regional electricity markets, and in the nature of transmission service provided over the project.

In summary, the transmission rights on the CSC will initially be physical Interregional Scheduling Rights. These rights will be held by the Project Shippers, implemented by the coordinated actions of TEUS, the NY ISO, and ISO-NE, and subject to any curtailments required for reliability under the NERC TLR procedures. Available Interregional Scheduling Rights will be posted on the CSC Interconnector OASIS system administered by TEUS. These Interregional Scheduling Rights will be available for bids for sale and purchase in the secondary market.

Q. Why does TEUS propose to use the open-season process to determine the final capacity of the CSC Interconnector?

A. This market assessment is essential to allow market-driven investments to occur. In order to finance the project, TEUS needs indications from potential shippers of their willingness to purchase Interregional Scheduling Rights on the project. These indications (and ultimately, the binding financial commitments executed by the successful open season respondents and TEUS) would be the financial justification for any investment decision, and would help determine the ultimate capacity of the
CSC Interconnector. TEUS will use the open season process and contemporaneous
discussions with project financers to determine the ultimate size of the project.

Because the CSC Interconnector project does not have access to a guaranteed revenue
stream (e.g. through a mandatory grid access charge), investors must engage in this
risk evaluation process. Investments with market risk require both the opportunity to
earn market returns and to evaluate and mitigate those risks.

IV. THE CSC INTERCONNECTOR’S ROLE IN COMPETITIVE ELECTRICITY
MARKETS

Q. Is there a role for market-based transmission investments in competitive electricity
markets?

A. Yes. As Professor Hogan states in his paper, “Market-Based Transmission
Investments and Competitive Electricity Markets” (included as Exhibit 4 of this
filing):

With the proper market institutions, there could be substantial
opportunities for market-based transmission investments. The
basic market elements include a coordinated spot market
implemented by the system operator through a bid-based, security-
constrained economic dispatch. This model would include
locational prices which provide the essential tools to create point-
to-point financial transmission rights in the form of transmission
congestion contracts.…

Those working to design market institutions should ensure that the
market-based transmission investment option is included, not
foreclosed from an unexamined judgment that only regulated
monopoly solutions would work.

Exhibit 4 at 7.
The CSC Interconnector is a prime example of a market-based transmission investment resulting from the efficient competitive electricity market structure described in Exhibit 4 and implemented (with Commission approval) by PJM, the NY ISO and (on a conceptual basis) ISO-NE.

Q. Please summarize the efficient competitive electricity market structure described in Exhibit 4.

A. The competitive electricity market structure described in Exhibit 4 is characterized by a bid-based spot market coordinated and dispatched by a system operator which would be responsible for maintaining the reliability and integrity of the transmission system. This market structure includes a system of potentially different spot market prices for different locations on the interconnected transmission grid. For any given trading period, the location-based marginal prices ("LBMPs") at the various transmission nodes reflect the cost of transmission congestion between those nodes at that time. Those LBMPs also clearly signal the current market value of incremental transmission capacity between those nodes. The market structure includes a system of tradeable transmission rights in order for market participants to obtain \textit{ex ante} price certainty against the cost of congestion in the transmission system. Most importantly, these tradeable transmission rights, and the associated LBMPs, also allow investors and users to evaluate proposals for new transmission investments that will create more rights. Thus, the efficient expansion of the grid can be accomplished through the decentralized action of users and investors responding to LBMPs. In Exhibit 4, Professor Hogan explains in detail how such transmission rights would be developed.
and how those transmission rights (together with LBMPs) create an efficient and competitive electricity market.

Q. What is the role of merchant transmission projects within this market structure?

A. Merchant transmission projects such as the CSC Interconnector are the natural response to the price signals provided by LBMPs under these market structures and the resulting ability to realize that value through the sale of transmission rights in these markets. LBMPs provide the market value of energy at the different nodes. Differences in LBMPs between different nodes signal the market value of incremental transmission between those nodes. These price signals allow market participants to efficiently compare generation and transmission investments, thus avoiding any bias towards (or away from) either generation or transmission options.

If new transmission investments are justified by the differences between LBMPs (including any locational differences in capacity values), tradeable transmission rights allow the holders of those transmission rights to realize the market value of the merchant transmission project. These rights can be either physical Interregional Scheduling Rights (such as the rights that will initially be sold to shippers on the CSC Interconnector) or the more flexible financial rights to congestion rentals discussed in Exhibit 4. Either form of these rights can allow the rights holders to arbitrage the locational differences in capacity and energy prices and/or to obtain ex ante price certainty against congestion costs. In turn, investors in the project can capture the project’s market value by selling the transmission rights created by the project at
Location-Differential Rates. Thus, the combination of locational prices and tradeable
transmission rights are the necessary conditions for market solutions to transmission
congestion, including market-driven investments in new transmission.

Q. Are there any existing markets which approximate this market structure?
A. Yes. Most features of the competitive market described by Professor Hogan are in
place in various electricity markets in the United States and several other countries.
In the U.S., PJM has been operating substantially such a market since April 1998.
The Commission has approved a similar market structure for the New York market.
Finally, as part of its response to the Commission’s requirement for a congestion
management system, ISO-NE intends to implement a system of locational prices with
financial transmission congestion rights within New England. We believe that these
modifications to the ISO-NE market and the full operation of the New York market
will be in place prior to the projected in-service date of the CSC Interconnector (early
2002).

All three of these regional electricity markets (PJM, NY ISO and ISO-NE) share the
bedrock elements of the efficient market described in Exhibit 4, namely:
1. bid-based, security constrained economic dispatch available to energy
   producers and consumers;
2. spot market prices resulting from that dispatch which (1) reflect the marginal
   value of energy at each node on the transmission system, and (2) explicate the
   marginal value of transmission between those nodes;
3. financial transmission rights within the respective ISO that allow the holder of
those rights to obtain *ex ante* price certainty against the cost of transmission
congestion associated with locational differences in spot market prices;

4. valuation of those transmission rights by market processes, either through
auctions of long-term rights or the spot market settlement mechanisms; and

5. assignment of the incremental transmission rights associated with new
transmission assets to the entities that financially support the investment in
those assets.

The Commission has reviewed and approved all of these elements in the various
filings by PJM, the NY ISO and (on a conceptual basis) ISO-NE.

Q. How does the CSC Interconnector integrate with the market structures in New York
and New England?

A. The CSC Interconnector is an entrepreneurial response to the evolving electricity
markets in New England and New York. The ability to move power between these
markets is limited and is frequently constrained. In addition, Long Island represents a
classic “load pocket” where the limited transmission between Long Island and the
mainland has meant that demand on Long Island is met primarily from higher cost
on-island generation resources. Prior to the restructuring of the regional electricity
markets, the economic impact of Long Island’s isolation from the electricity markets
in New York and New England was obscured by average cost ratemaking and
bundled service. While this economic impact was not entirely hidden, there was little
incentive for low-cost expansions of transmission capacity between the two markets.
Hence, additional interconnections between Long Island and the mainland were often studied but never developed.

The wholesale market reforms advanced by the Commission and state legislative and regulatory bodies have changed this picture. These reforms, coupled with the system of locational market prices and associated transmission rights being implemented in New York and New England, provide the necessary signals and framework for market-based solutions to transmission congestion. In particular, the market structures in New York and New England now more clearly identify the market value of new transmission capacity between Long Island and the mainland, and more readily allow the users of a new interconnection to realize that market value.

The CSC Interconnector will create additional interregional transmission capacity between New York and New England. As discussed above, the rights to use this capacity will initially take the form of Interregional Scheduling Rights administered by TEUS in coordination with the ISOs in New York and New England.

V. AN ANALYTICAL FRAMEWORK FOR ALLOWING MARKET-BASED RATES FOR MERCHANT TRANSMISSION PROJECTS

Q. How should the Commission evaluate requests for Location-Differential Rates for a merchant transmission project such as the CSC Interconnector?

A. TEUS recognizes that the concept of a merchant transmission facility with Location-Differential Rate authority is a novel one. In light of the innovative nature of our request, we have developed an analytical framework as a possible basis for evaluating
this proposal and other similar proposals so as to ensure that any precedent that is established does not extend beyond those circumstances in which Location-Differential Rates are clearly justified.

Q. Have market-based rates for transmission services been accepted elsewhere?
A. Yes. In Australia, a framework for market-based transmission service has recently been implemented. TEUS and its affiliates have been active participants in the Australian electricity market and presently have two interconnector projects under development. Both of these projects will provide transmission service at negotiated rates using controllable transmission technology.

Q. Please describe how the Australian electricity market incorporates market-based transmission investments.
A. In the Australian National Electricity Market, transmission providers (“Network Service Providers”) can provide “Market Network Services” over interconnections that meet specific criteria for market-based rate authority. The criteria for market-based rates, entitled “Entrepreneurial Interconnectors: Safe Harbour Provisions” are included in our filing for informational purposes as Appendix 1 to this Exhibit 3. The criteria include a requirement that the project not receive any guaranteed revenue and thus bear all market risks for the investment. The “safe harbor” criteria also require that the interconnector be a two-terminal project with physically controllable flows scheduled by the independent system operator.
It is important to note that these provisions are intentionally restrictive. In developing these provisions, the Australian market participants recognized that serious barriers existed to allowing market-based rates for all transmission service. These impediments included the operational issues that arise in a free-flowing AC meshed network which make it difficult to apply a market-based approach, as referenced by Professor Hogan in Exhibit 4, and the commercial issues associated with a single entity owning all regulated transmission within a region. Consequently, as in the U.S., Australian regulators treat transmission services over the meshed AC network as cost-based services provided by regulated businesses. However, the Australian market has concluded that under some circumstances it is feasible and appropriate to adopt a market-based approach for pricing inter-regional transmission service. It was recognized that, with the safeguards included in the Safe Harbour Criteria, market-based inter-regional transmission projects would avoid the regulatory problems and costs associated with centrally managed transmission expansion and would extend the benefits of competitive pressures to the transmission sector.

Q. How do Market Network Services work in the context of the Australian National Electricity Market?

A. Entities with contracted capacity on the merchant interconnector may put in “transport bids” into the regional spot market. Such transmission bids, together with the energy price in the exporting region, can set the energy price in the importing region. The energy flows over the merchant interconnector are scheduled and dispatched by the Australian independent system operator as part of the overall bid-
based, security-constrained National Electricity Market. Holders of capacity on the
interconnector are entitled to retain as revenue the “value added” from the
transmission service (essentially, the difference between the market prices in each
region multiplied by their contracted capacity, with adjustments for electrical losses).

Q. Please describe TEUS’ merchant transmission projects in Australia.

A. TEUS and its project partners are building Directlink, a merchant transmission
interconnector linking (for the first time) the states of Queensland and New South
Wales. Directlink will consist of approximately 40 miles of HVDC transmission
cable in existing, negotiated rights-of-way and easements, with no overhead
transmission lines. The interconnector will have a transfer capability of
approximately 180 MW. TEUS and its project partners are constructing Directlink
without long-term contracts, relying instead on an auction process for selling capacity
(or financial hedging instruments tied to the transmission capacity) on the
interconnector. This auction is presently underway. An additional characteristic of
Directlink is that the project’s owners (one of which is an affiliate of TEUS) may
elect to retain capacity on Directlink for their own account and use it to participate
directly in the spot market as described above.

In addition to Directlink, TEUS is evaluating several other projects in Australia.
Recently, TEUS announced its second Australian project, Murraylink, which will
interconnect the states of New South Wales and South Australia. Like Directlink,
Murraylink will be a merchant interconnector meeting the Safe Harbour Criteria for
Market Network Services. More information on these projects can be found at the
web site for TEUS’ Australian subsidiary (TransÉnergie Australia Pty. Ltd.) at

Q. What evaluation criteria should be used for the U.S. markets to determine whether to
allow market-based rates for a merchant transmission project?

A. We submit for the Commission’s consideration the following evaluation criteria for
allowing market-based rates for merchant transmission projects. These criteria are
based on the “safe harbor” provisions for allowing market-based transmission rates
for merchant transmission projects developed and now being implemented in
Australia, where TEUS and its project partners are currently constructing the
merchant Directlink interconnector described above. The safe harbor provisions in
Australia will allow the Directlink Project to earn market-based returns for assuming
market risks. Similar provisions in the U.S. (with changes to recognize the specific
natures of the diverse electricity markets in the U.S.) will encourage similar
transmission investments in the U.S.

SUGGESTED “SAFE HARBOR” CRITERIA FOR LOCATION-
DIFFERENTIAL TRANSMISSION RATES

(1) The annual costs of the merchant transmission project (including annual
capital costs) must not be included in or recovered through any mandatory
grid access fee.
An obvious requirement for market-based returns should be that the project owners face market risks. Just as the annual costs of new exempt wholesale generators with market-based rate authority are not included in any generation rate base, so should the cost of new merchant transmission projects be similarly excluded from mandatory grid access charges. This exclusion of the project’s costs from any such mandatory charges will ensure that non-users of the project do not pay its costs. By protecting non-users from the project’s costs, the project owners will be exposed to the full market risk of their investment decision.

(2) The merchant transmission project must create tradable transmission rights. The corollary to protecting non-users from the project cost is directing the project’s benefits to the owners of transmission rights arising from the project. As explained by Professor Hogan in Exhibit 4, tradable transmission rights are essential for the creation of a truly efficient and competitive electricity market that fosters market-based transmission investments.

Recognizing that different merchant transmission projects may operate in different market environments, we note that a merchant transmission project can create tradable transmission rights in one of two ways:

a. By creating financial transmission rights within an integrated electricity market with the features described in Exhibit 4, or

b. By creating Interregional Scheduling Rights over a point-to-point transmission project (such as the CSC Interconnector), where the flow of energy over the
project can be directly controlled and dispatched in response to market or ISO
instructions.

This latter scenario is the idealized “controllable flow” case described by Professor
Hogan in pages 3-5 of Exhibit 4.

Either of these alternatives would create transmission rights that can be quantified, valued and traded by market participants. Transmission rights that are identifiable, separable and tradable (whether financial rights created within the electricity markets described in Exhibit 4, or Interregional Scheduling Rights over fully controllable projects such as HVDC links) can be assigned market values according to market mechanisms (i.e., LBMPs). As discussed in Exhibit 4, these types of transmission rights can be sold at Location Differential Rates that support the financial investment in the project, and the development of these projects can be left to the market. Thus, we suggest that a merchant transmission project must create tradable transmission rights (either financial transmission rights or more physical scheduling rights) in order to receive Location Differential Rate authority.

(3) The merchant transmission project should not impair any pre-existing property rights to use the grid. In other words, the project should receive the incremental transmission rights created by the project (and only those rights).

A corollary to Criterion #1 (protect non-users) and Criterion #2 (create tradable rights) is a requirement that pre-existing transmission property rights not be impaired by either (1) the construction or operation of the project or (2) the sale of the
transmission rights created by the project. By requiring the merchant transmission project to not impair pre-existing property rights (particularly any financial transmission rights already allocated), the construction or operation of the merchant project will not financially harm the holders of those rights.

In the parlance of the electricity market described in Exhibit 4, the merchant transmission project would be awarded the incremental feasible financial transmission rights that were associated with the project (and only those rights). As illustration, consider a new point-to-point AC transmission line between two nodes. Suppose that this new line had a nominal thermal capacity of 100 MW, that the nodes were already linked by an existing parallel line with a capacity of 200 MW, and that the new feasible injection/withdrawal from Node A to Node B was now 270 MW instead of 300 MW, with the 30 MW reduction due to a limitation resulting from the contingency analysis used in the feasibility test. Finally, assume that the ISO administering those transmission facilities had already auctioned 200 MW of financial transmission rights from Node A to Node B. In this case, the merchant transmission project has created only 70 MW of incremental transmission rights between the two nodes, and should only be allowed to sell 70 MW of such transmission capacity.

(4) Physical energy flows over the merchant transmission project should be coordinated and scheduled by a neutral, independent operator in accordance with the applicable reliability criteria of NERC and its regional councils.
The requirement that a merchant transmission project be scheduled as part of the security-constrained economic dispatch regime (or regimes) of the system (or systems) to which it is interconnected should also be a prerequisite for market based rate authority. Scheduling and dispatch by a neutral party (such as an ISO or other entity as approved by the Commission) ensures that reliability of the grid will not be compromised, and that physical access to the merchant transmission project is provided in a non-discriminatory manner. In Exhibit 4, Professor Hogan also emphasizes the need for a system operator to coordinate a security-constrained economic dispatch as an integral part of efficient and competitive electricity markets. Thus, we suggest that scheduling by an independent operator in accordance with accepted reliability criteria should be a prerequisite for market-based rate authority.

(5) The merchant transmission project must not preclude access to any essential facilities.

A merchant transmission project should not preclude access by any party (including potential competitors) to any facilities deemed as essential for participation in the competitive electricity market. For example, the merchant project should not preclude competitors from developing similar transmission interconnections between the same regions (although the commercial attractiveness of the second investment may change once the first project goes into service).

This criterion will assure that the merchant transmission project does not create any artificial barriers to entry, or gain any market power from the control of an essential
facility. The possibility of market power abuses by the owners of such essential facilities has long been recognized by the Commission.

A corollary to this criterion is the requirement that merchant status should not be granted to projects that intend to rely on eminent domain power to obtain necessary rights-of-way and/or easements. The use of eminent domain authority assumes that a project is being constructed for purposes other than the commercial viability of the investment. In order to obtain the authority to negotiate rates, a project should not have the authority to take land through an eminent domain process.

(6) Merchant transmission projects should be subject to the same market power considerations as merchant generation projects or power marketers. We suggest that proposals for market-based rates for merchant transmission projects should be subject to the same market power review and monitoring mechanisms as energy producers and traders that receive authority to charge market-based prices. Furthermore, we suggest that the holders of the transmission rights created by the project (whether the project owners or third parties) should be included in the applicable market monitoring and mitigation processes of the regional electricity market.

(7) At this early stage of the market for merchant transmission services, the merchant transmission project should use a non-discriminatory open season process to initially allocate transmission rights created by the project.
This allocation will assure that all the capacity on the CSC Interconnector will be offered to all potential purchasers in a transparent and non-discriminatory manner. In the long run, we do not believe that this criterion is essential to allow market-based rates for merchant transmission projects. As discussed in pages 32 through 34 of Exhibit 4, Professor Hogan notes that even the withholding of physical transmission capacity by the owners of that transmission capacity can be consistent with competitive market dynamics. As long as other entrants can freely respond to the competitive market conditions, withholding of physical transmission capacity would generate scarcity rents, not monopoly rents. We believe that once merchant transmission projects become more commonplace, new transmission capacity can be treated in the same manner as new generation capacity – offered by willing sellers to willing buyers, who may or may not agree upon the terms and conditions for those sales.

Q. How does the CSC Interconnector fit these criteria?

A. The CSC Interconnector meets all of these criteria for Location-Differential Rates:

   1. *The CSC Interconnector will be a truly merchant facility*

      The costs of the project will be recovered solely through sales of transmission service (initially as Interregional Scheduling Rights) to shippers who voluntarily elect to purchase such capacity. None of the project’s costs will be included in a mandatory grid access charge in either New York or New England. Hence, no users of the New York or New England grids will be compelled to pay for any of the project’s costs
unless they voluntarily purchase service over it. The CSC Interconnector will be a merchant transmission project.

2. The CSC Interconnector will create tradable transmission rights.

The CSC Interconnector will be a two-terminal HVDC link connecting the regional electricity markets in New England and New York. Flows of energy over the project will be directly controllable. Schedules for such flow can be set independently from the scheduled flows on other interties or the specific generation dispatched in each market. The scheduled transfers over the CSC Interconnector are subject only to the physical limitation of the project facilities, the capacity of the AC networks at the sending and receiving ends and the NERC and NPCC reliability criteria for such interchanges. Since the physical flow of energy over the CSC Interconnector can be directly scheduled and controlled, the Interregional Scheduling Rights over the project can be quantified and traded in the same manner as the financial transmission rights described in Exhibit 4. The CSC Interconnector will be an example of the idealized “controllable flow” case discussed in pages 3-5 of Exhibit 4. In this manner, the CSC Interconnector will create tradable transmission rights between New England and New York.

3. The CSC Interconnector will not impair any pre-existing property rights to use the transmission grids in New York or New England.

As discussed above, we believe that a condition for Location Differential Rates for a merchant transmission project should be that the project not impair existing property
rights, including the existing rights to use the grid. Through the on-going
interconnection application process with the NY ISO and ISO-NE, the incremental
interregional transmission rights and benefits created by the CSC Interconnector will
be determined.

In the efficient competitive electricity markets described in Exhibit 4, the marginal
transmission rights associated with a new transmission investment would be
determined by identifying the incremental sets of feasible injection/withdrawal pairs
that were created by the project. These incremental injection/withdrawal pairs would
be determined given the (1) the physical capacity of the grid after the expansion and
(2) the sets of injection/withdrawal pairs that had already been confirmed as feasible
(and for which financial transmission rights had been sold). Only the incremental
increases in potential grid use would be allocated to the merchant transmission
project. In other words, the project would receive only the incremental firm
transmission rights created by the project, with such incremental rights determined
after recognizing the firm rights that had already been sold. Thus, for the competitive
electricity markets described in Exhibit 4, the incremental transmission rights for a
merchant transmission project will be the incremental feasible financial transmission
rights created by the project, as determined by the system operator.

As discussed above, the transmission rights associated with the CSC Interconnector
will initially be Interregional Scheduling Rights. These physical rights will apply
only to the facilities of the CSC Interconnector. Shippers on the project will be
responsible for obtaining financial transmission rights within New York and New England to hedge their prices at the DC terminals of the CSC Interconnector, if they desire those rights. The Interregional Scheduling Rights for the CSC Interconnector will only be between the two DC terminals and, thus, will not affect any pre-existing firm transmission rights over the New England or New York grids.

4. *Dispatch of the CSC Interconnector will be coordinated by TEUS and by the New York and New England ISOs, in accordance with NERC and NPCC reliability criteria.*

The CSC Interconnector will be scheduled by the coordinated efforts of TEUS as the system operator, the NY ISO, and ISO-NE using the same processes as the scheduling of existing interties between the two control areas. To further ensure that the dispatch of the CSC Interconnector will be fully coordinated between these two ISOs and TEUS (as operator of the project), TEUS and/or its project subsidiaries will (1) become a member of the NY ISO and ISO-NE and (2) become a separate member of NERC with its own security coordinator. Finally, TEUS will develop and implement the appropriate requirements (including standards of conduct) to ensure open and neutral access to the CSC Interconnector. As part of this commitment to independence, as explained in item 6 below, TEUS will commit to not allow any of its affiliates to participate in the initial open season process to allocate transmission rights over the CSC Interconnector.
5. *The CSC Interconnector will not preclude access to any facilities deemed to be essential for public service.*

The transmission facilities owned by the project will not encompass any facilities deemed to be essential for public service or part of an existing monopoly franchise area. Furthermore, none of the land used by the project will be acquired by an eminent domain taking, since the project will only use land or land rights acquired through processes open to all other competitors (e.g., negotiated acquisition of or access to land on Long Island and Connecticut). Potential competitors (such as merchant generation projects in either market or a competing merchant transmission project) will continue to have free entry into the New York and New England markets, and will not face any artificial barrier to entry erected by the CSC Interconnector. (We note that this ability of potential competitors to enter the market will discipline the prices that can be charged for service over the project.) Hence, the CSC Interconnector will not preclude access by another party (including competitors) to any essential facilities.

6. *The CSC Interconnector will not have any market power in either New York or New England, as fully explained in Dr. Shanker's testimony (Exhibit 6).*

We believe that a new 600 MW generation plant located in either Long Island or in Connecticut would not be considered to have market power in either of these electricity markets. We note that authority for market-based rates has already been granted to existing generators within New England and on Long Island, and that new generation projects in either of these regions do not need to file a market power study.
to receive market-based rate authority. Hence, we believe that the CSC Interconnector should receive the proposed Location-Differential authority without the need for any market power study.

However, recognizing the innovation of our proposal, and to further err on the side of caution, we submit a market power study with this application. Exhibit 6 is a market power study performed by Dr. Roy Shanker. In that study, Dr. Shanker concludes that a shipper on the CSC Interconnector will not have market power in either New England or Long Island, even if one shipper controlled all of the capacity on the project.

Finally, we recognize that the use of the CSC Interconnector by affiliates of TEUS might raise some market power concerns. We believe for the reasons explained by Dr. Shanker that these concerns would not be warranted. But to err on the side of caution, TEUS will commit to not allow any of its affiliates to participate in the initial open season process. While affiliates of TEUS may (or may not) eventually acquire transmission rights on the CSC Interconnector in the secondary market, through the CSC Interconnector’s OASIS, any comments with respect to such secondary market acquisition can be mitigated through the relevant market monitoring mechanisms. Dr. Shanker addresses these market monitoring mechanisms in his testimony. TEUS will cooperate fully with these market monitoring processes. To the extent necessary, TEUS will assist these processes by providing information on the ownership of scheduling rights to each ISO, including tracking activity in the secondary market.
These commitments by TEUS to sell transmission rights on the CSC Interconnector through an open season process and to exclude its affiliates from that initial open season process should eliminate any potential market power concerns regarding the project.

7. **Interregional Scheduling Rights on the CSC Interconnector will be initially allocated through an open season process.**

As discussed above, the CSC Interconnector will rely on an open season to determine the initial size of the project and to initially allocate the transmission rights associated with the project. Capacity that is not sold through the open season process will be posted on the CSC Interconnector’s OASIS operated by TEUS. Capacity sold but not scheduled will be posted on CSC Interconnector’s OASIS, and sales proceeds will be directed to the capacity owner.

Q. How are these criteria and the CSC Interconnector consistent with the Commission’s present and emerging policies regarding competitive electricity markets?

A. As more fully addressed in the Petition accompanying our filing, our request for market based rate authority is fully consistent with the development of competitive electricity markets. The Commission’s recent RTO NOPR clearly delineates the Commission’s areas of concern regarding the present state of electricity markets, even after implementation of the open access policies of Order Nos. 888 et al.: (a) continued undue discrimination by transmission owners in favor of their affiliated
merchant entities; and (b) continued inefficiencies and lack of incentives for new
transmission investment. Allowing Location-Differential Rates for a merchant
transmission project such as the CSC Interconnector will help alleviate both of the
conscerns expressed by the Commission. In particular, the market-based nature of the
CSC Interconnector is entirely consistent with the Commission’s expressed
preference for market-based solutions for relieving transmission congestion and
encouraging new transmission investment.

V. THE CROSS SOUND CABLE INTERCONNECTOR POINT-TO-POINT
TRANSMISSION TARIFF

Q. Please explain the derivation of the Point-to-Point Transmission Tariff for the CSC
Interconnector.

A. In examining the economics of constructing the CSC Interconnector and exposing the
project to full market competition, TEUS has had to confront two hard realities. First,
while the energy price differentials between the two markets immediately adjacent
would broadly appear to justify the project’s construction, how the demand for
Interregional Scheduling Rights on the CSC Interconnector will actually emerge, and
change over time, is far from certain. Second, the CSC Interconnector will be
entirely dependent financially on the returns from this uncertain demand.

Not only is it currently unclear what demand there will actually be for Interregional
Scheduling Rights on the line (and for what amounts, duration and prices and under
what conditions), but it is also uncertain how long current demand patterns will last
and how much they will change when they do. Over time, major changes in either
adjacent ISO market could occur by virtue of:

• new generation built in either market;
• new transmission built between the markets;
• the eventual integration of these markets (e.g., under a larger RTO); or
• basic changes in demand patterns (possibly accelerated by distributed
generation or by technological innovations that will reduce demand, allow for
price-sensitive demand bidding, and/or provide for direct price-based load
control).\footnote{See, e.g., Comments of the Edison Electric Institute, Regional Transmission Organizations, Notice of Proposed Rulemaking, Docket No. RM99-2-000 at 37-38.}

Q. How has TEUS addressed this uncertainty in demand for the CSC Interconnector?
A. TEUS has concluded that the only efficient means of approaching this initial (and
ongoing) demand uncertainty is to conduct an open season for the entire capacity on
the line, i.e., not contemplating any reserve for the project sponsor, TEUS, or its
affiliates. This open season will achieve two important goals:

1) identify the initial demand for capacity and thereby determine:

(a) whether the project is financially feasible at all; and
(b) the appropriate sizing of the line, recognizing that, with some
economies of scale in HVDC transmission technology and the
possibility of future unidentified demand, some additional transfer
capability (beyond the immediate need of the market) may be justified;

and

2) provide an open competitive and non-discriminatory basis for access to the new facility by market participants.

However, in light of the uncertainty of demand, it is crucial that TEUS be fully responsive to customer requirements and possibly rapid changes in these requirements. Just as the Commission, and the industry, has now recognized that electricity is not a single product (bundled and offered by producers with few if any options for customers), today's electricity markets (following telecommunications and other deregulated former "utility" markets) reflect an increasingly wide array of products and services (traditionally characterized as generation, transmission or ancillary services). Commission policy has long since recognized this emerging reality and underscored the importance of customer choice as the principal driving force for new economic and technological developments in the industry. TEUS believes customer choice is the most efficient way, indeed perhaps the only feasible way, to define the capacity offering on the CSC Interconnector.

In order to achieve this demand responsiveness, TEUS will need maximum flexibility under the tariff on file with the Commission. After extensive review of current tariffs on file at the Commission, TEUS believes the most appropriate analogy, and starting point for the CSC Interconnector tariff, is the form of tariff on file for numerous generating facilities with market-based pricing authority. However, such a tariff

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model must be duly adapted to the needs of transmission service and enhanced by the
specific commitments made in this case (e.g., as to TEUS not reserving capacity for
itself during any open season or auction process).

Q. Did TEUS consider using the Commission’s Order No. 888 pro forma tariff for the
CSC Interconnector?

A. Yes. TEUS has considered seriously the alternative of using the Order No. 888 pro
forma tariff and attempting to adapt it to the CSC Interconnector, but has concluded it
is not the best approach for several reasons. First, the Order No. 888 pro forma tariff
is based upon a fundamentally different underlying economic assumption (that
applies to virtually all other transmission under Commission regulation) -- that the
facility's revenue requirement will be recovered in some way from a mandatory grid
access charge imposed by a monopoly provider on all users of an integrated system.

In addition, the Order No. 888 pro forma tariff is predicated on a fully-integrated AC
transmission network. As a result, most of the requirements or components of the
Order No. 888 pro forma tariff are simply not applicable to merchant interconnectors
that take full market risk and do not rely on regulated monopoly provider revenue
requirements. Hence, direct application of the Order No. 888 pro forma tariff
provision will consist largely of a morass of legitimate exclusions from its provisions.

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3 For example, all references in the Order No. 888 Tariff to revenue requirements, network integration
transmission service, transmission of energy sold to third parties, and the Transmission Provider's obligation to
expand capacity, have no relevance to the CSC Interconnector.
Because the Order No. 888 tariff is based on fundamental regulatory assumptions not applicable here, attempts to utilize that model, even if amended, will undoubtedly cause greater confusion than to utilize a tariff crafted to address the circumstances of the CSC Interconnector.

In light of this review, TEUS proposes the attached tariff (Exhibit 5), which is based on the typical tariff for market-based rates for generation facilities but duly adapted to transmission and enhanced by the distinctive need of this project.

Q. Does this conclude your testimony?

A. Yes.