

**RAPPORT D'EXPERTISE DE  
PHILIP Q. HANSER**



**QUÉBEC**

**R-3669-2008  
Phase 2**

**RÉGIE DE L'ÉNERGIE**

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**HYDRO-QUÉBEC, when carrying on electric  
transmission activities**

**and**

**Intervenors**

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**EXPERT REPORT**

**OF**

**PHILIP Q HANSER**

**On behalf of**

**HYDRO-QUÉBEC TRANSÉNERGIE**

**June 2010**

## **I. INTRODUCTION**

1. My name is Philip Q Hanser. I am a Principal of *The Brattle Group*, an economic and management consulting firm with offices in Cambridge, Massachusetts; Washington, D.C.; San Francisco, California; London, England; and Brussels, Belgium.
2. I have been a Principal at *The Brattle Group* in its Cambridge office for over ten years and have nearly thirty years of experience in the electric power industry. I have testified previously before the Régie de l'Énergie ("the Régie"), the Federal Energy Regulatory Commission ("FERC") and various U.S. state public utility commissions, as well as in U.S. federal and state courts as an expert witness on electricity transmission and market design and regulation issues, among other topics. My statement of qualifications, including references to testimony I have given over the past five years, is attached as Attachment 1.
3. *The Brattle Group* has been retained by Hydro-Québec TransÉnergie ("HQT" or "TransÉnergie" or "HQ TransÉnergie") to review its methodology to coordinate data and assumptions to achieve consistent available transfer capability ("ATC") values on either side of an interconnection with its neighbouring systems (referred as "ATC Coordination"), and to comment on its conformity with FERC Order 890.
4. I understand that this review is performed in the context of a dedicated phase ("Phase 2") of HQT's rate application R-3669-2008 concerning certain modifications to HQT's OATT. HQT's methodology for ATC Coordination is described in the revised Attachment C-1 to HQT's OATT ("Attachment C-1"), attached as Attachment 2.

## **II. EXECUTIVE SUMMARY**

5. Following a review of the relevant documents, I conclude that HQT's methodology described in Attachment C-1 ("Methodology") for ATC Coordination is consistent with FERC Order 890. Specifically, FERC has elaborated that the intention of the ATC Coordination policy is to ensure that transmission service providers ("TSPs") use a consistent and transparent methodology in calculating the ATC and to ensure that transmission service is provided in a non-discriminatory manner. In a related decision,<sup>1</sup>

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<sup>1</sup> Docket No. RM08-19-000, et al.; Order No. 729, November 24, 2009.

FERC stated: “Improving transparency and consistency of available transfer capability calculation methodologies will eliminate transmission service providers’ wide discretion in calculating available transfer capability and ensure that customers are treated fairly in seeking alternative power supplies.”<sup>2</sup> I have reviewed TransÉnergie’s Methodology for the calculations of ATC for interfaces with neighbouring systems and I conclude that TransÉnergie has put into place a procedure to ensure that its ATC calculations are consistent with neighbouring systems’ ratings.

### **III. SCOPE OF MANDATE**

6. This report addresses the following matters:

- (a) Provide and discuss a brief history of FERC’s open-access transmission policy as it relates to ATC Coordination, with specific reference to FERC Orders and *pro forma* OATT.
- (b) Discuss whether HQT’s Methodology for ATC Coordination is consistent and complies with the relevant FERC Orders.

### **IV. ANALYSIS**

7. My analysis is organized as follows: In Section A, I provide a brief history of FERC’s open access transmission policy, notably with reference to Orders 888, 889, 890, 890A, 890B and 890C and *pro forma* OATT. In Section B, I describe HQT’s Methodology for ATC Coordination. In Section C, I describe the characteristics of HQT’s transmission system relevant for purposes of my report and analyse HQT’s Methodology in light of applicable principles advanced and decisions rendered by FERC, taking into account the characteristics of HQT’s transmission system.

#### **A. FERC ORDERS**

8. FERC issued Order 888 in April 1996 to foster competition in wholesale power markets. This order requires all jurisdictional utilities to file an open-access transmission tariff (“OATT”) providing access to their transmission systems on terms and conditions

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<sup>2</sup> Docket No. RM08-19-000, et al.; Order No. 729, November 24, 2009, paragraph 2.

comparable to those that the utility provides to its own generation capacity. In conjunction with Order 888, FERC issued a “*pro forma*” OATT that specifies the type of services that must be provided by a transmission utility.

9. FERC Order 889, which was issued in parallel with Order 888, requires U.S. public utilities to establish an electronic open access information system (“OASIS”). FERC concluded that non-discriminatory access to transmission information was needed in order to have transmission services provided in a non-discriminatory manner. A TSP’s OASIS provides current and potential transmission customers with information, electronically provided, about available transmission capability and prices. Providing such information on a timely and non-discriminatory basis facilitates a primary objective of FERC policy—the economically efficient trade of electricity in wholesale power markets. Through their OASIS, transmission service providers must make available to others the same transmission information that is available to their own employees and that is pertinent to decisions they make involving the sale or purchase of electricity. The OASIS allows potential transmission customers to determine the availability of transfer capability and helps to ensure that utilities do not use their ownership, operation, or control of transmission to deny access unfairly.
10. On February 16, 2007, FERC issued Order 890 which confirmed certain reforms to correct perceived flaws in the *pro forma* OATT adopted in Orders 888 and 889 and to ensure that transmission services are provided on a just and reasonable basis. Specifically, Order 890 modified the *pro forma* OATT in several areas, including the calculation of ATC.
11. Specifically applicable to the calculation of ATC, FERC desires to increase consistency and transparency in the methodology for calculating ATC to reduce the potential for undue discrimination in providing transmission service and to reduce transmission service providers’ ability to exercise discretion that might discriminate certain market participants. In that regard, while FERC did not require a “lowest common denominator” approach in calculating ATCs,<sup>3</sup> it emphasized the importance of having industry-wide

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<sup>3</sup> FERC Order 890, February 16, 2007, paragraph 208.

consistency for all ATC components and certain data inputs and exchange, modeling assumptions, calculation frequency, and coordination of data relevant for the calculation of ATC.<sup>4</sup>

12. Following FERC Order 890, three supplemental orders, namely Orders 890-A through 890-C, were issued to address further questions relating to ATC calculations across system interfaces and several other topics. For the purpose of this testimony, I will focus only the issues relating to the calculation of ATC in these subsequent orders.
13. FERC Order 890-A was issued on December 28, 2007. Among other topics addressed in Order 890-A, FERC answered questions about whether FERC meant to require adjacent transmission providers sharing a common interface to coordinate to provide consistent ATC values on either side of that interface. Specifically, FERC clarifies: "...adjacent transmission providers must coordinate and exchange data and assumptions to achieve consistent ATC values on either side of a single interface. This is applicable to any neighbouring transmission providers no matter whether they use the same or different ATC methodologies. We note, however, that the anticipated consistency is for available capability in the same direction across an interface."<sup>5</sup>
14. Following the issuance of Order 890-A, FERC issued Order 890-B on June 23, 2008, which further reaffirmed prior policies and provided additional clarifying explanations for several issues, including the proper calculation of ATC across a common interface with adjacent transmission systems. FERC confirmed its intention to require adjacent transmission providers to coordinate and exchange data and assumptions to achieve consistent ATC values on either side of a single interface. FERC stated that it recognizes "factors such as timing of reservation requests, acceptances, and confirmations, and multiple interfaces between and among transmission providers, can make it difficult to achieve coincidental, identical postings of ATC values on both sides of an interface."<sup>6</sup> However, FERC emphasized that ATC calculations performed with consistent data inputs

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<sup>4</sup> FERC Order 890, paragraph 210.

<sup>5</sup> FERC Order No. 890-A, December 28, 2007, paragraph 52.

<sup>6</sup> FERC Order 890-B, June 23, 2008, paragraph 15.

and assumptions should produce “predictable and sufficiently accurate, consistent, equivalent, and replicable results.”<sup>7</sup>

15. After Order 890-B was issued, requests for clarification and rehearing were received. Specifically relating to the ATC calculations, questions were raised about how different reservations on either side of an interface might impact the ratings.<sup>8</sup> In response to these and other questions, FERC issued Order 890-C on March 19, 2009. In that order, FERC clarified that transmission providers do not have to post identical ATC values on either side of an interface *in every instance and at all times*.<sup>9</sup> In addition, FERC reiterated its requirement in Order 890-B to achieve consistent ATC values through calculations that produce “sufficiently accurate, consistent, equivalent, and replicable results.” FERC acknowledged that in some cases where there are differences in reservation status or when there are multiple interfaces between transmission providers that it may not be possible or practical to achieve identical values. Although FERC’s focus on ATC calculation was with regard to its impact on markets, FERC realized that there were also reliability implications. As a result, it noted that the North American Electric Reliability Corporation (“NERC”) had proposed reliability standards governing the calculation of ATC and those standards should help produce “predictable and sufficiently accurate, consistent, equivalent, and replicable results.”

## **B. HQT’S METHODOLOGY FOR ATC COORDINATION**

16. From my reading of Attachment C-1 to HQT’s OATT, I understand that HQT’s intentions are to reflect FERC Order 890 and subsequent clarifying Orders 890-A through C by providing market participants the proper ATC values across its interfaces with neighbouring systems. I find that HQT’s procedures and formulae are developed to specifically deal with the issue of coordinating and exchanging data and assumptions with neighbouring systems to achieve consistent ATC values on either side of a single

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<sup>7</sup> FERC Order 890-B, paragraph 15 and Order 890, February 16, 2007, paragraph 210.

<sup>8</sup> FERC Order No. 890-C, March 19, 2009, paragraphs 4-6.

<sup>9</sup> FERC Order No. 890-C, paragraph 7, emphasis added.

interface. The HQT's formulae use the Transmission Reliability Margin ("TRM") to ensure that the ATCs on both the HQT and adjacent systems are consistent.

17. While FERC did not mandate precisely *how* each transmission service provider should exchange information and coordinate with neighbouring system, FERC was quite clear that it expects such a procedure be established.
18. FERC does not require the "least common denominator" approach. I interpret this to mean that FERC does not demand every transmission service provider to report the ATC across an interface to be the lower of the two ATCs from either side of an interface. However, given the unique features of HQT's interconnection with its neighbouring systems, which I will explain below, HQT's choice of using the "least common denominator" seems to be the only appropriate way to ensure that consistent ATC ratings are made on its interfaces with neighbouring systems.

### **C. COMPLIANCE OF HQT'S METHODOLOGY WITH FERC ORDER 890**

#### **(a) Characteristics and Distinguishing Features of HQT Transmission System**

19. For the purposes of our analysis, it is helpful to briefly describe certain characteristics and distinguishing features of HQT's transmission system and, as a result, how HQT's system differs from transmission systems in the U.S.
20. HQT operates the most extensive transmission system in North America, with more than 32,000 kilometres of lines and interties with systems in neighbouring provinces and states in the U.S. Northeast. One relatively unique feature of HQT's system is that it transmits large quantities of power over long distances at high voltage. Most of the load in Québec is located in the southern part of the Province (*e.g.*, Montréal) whereas some of the major generation plants are located in the north, far away from load centers (*e.g.*, James Bay). Given this essentially hub-and-spoke topology, and the need to move power over long distances, HQT found it economical to build very high-voltage 735 kilovolt lines to transmit power from remote regions to load centers in Southern Québec. Lines of this voltage or higher are found on only a few other transmission systems in North America. HQT also has several DC interties with neighbouring control areas.

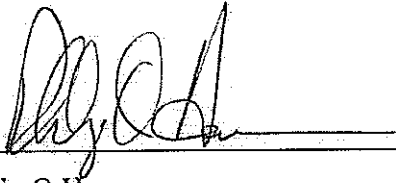
21. HQT's system differs in one notable respect from transmission systems in the U.S. In the U.S., all transmitting utilities belong to one of three Interconnections (the Eastern Interconnect, the Western Interconnect, and ERCOT (Texas)) and are electrically synchronous with all other transmission systems in their Interconnection. This means that transmitting utilities have "free flowing" interties with neighbouring systems, with the result that flows on one utility's system are affected by the loadings on other systems. HQT is asynchronous with the other systems that make up the Eastern Interconnection. The HQT system is interconnected with neighbouring systems through either "controllable" interties or "radial" interties, which are blocks of generation or load which are islanded from HQT in order to be attached to another system through AC interties. This means that HQT's grid is not influenced by power flows on other systems, as was demonstrated during the widespread power outage that occurred in the northeastern U.S. and portions of Canada in August 2003. TransÉnergie's system was not affected by this outage, except for a small portion of the Province's load that is connected to Ontario by AC transmission lines, but which was electrically isolated from the rest of the HQT system.
22. HQT uses the HQT Point as a representation of its system as of whole, excluding the other OASIS reception and delivery points. The use of HQT Point greatly simplifies the reservation and scheduling of transmission service.
23. As stated in the HQT document "HQT Point" (exhibit HQT-27), the creation of the synthetic HQT Point was made possible both by the fact that the TransÉnergie system is asynchronous with the other systems in the Eastern Interconnection and because it is not subject to internal congestion. Given the absence of internal congestion in HQT's system, there is no reason to list ATC for 240 distinct path pairs. Therefore, for planning purposes, HQT can be seen from external regions as a single point.
  - (b) **Comparison of HQT's Methodology with ATC Coordination Methodologies Used in United States and Its Conformity with FERC Orders**
24. It appears that since the issue of Order 890, many utilities in the U.S. have submitted revised OATTs incorporating the updated ATC calculation methodologies in Attachment Cs of each various transmission service providers' OATT. Included in some of these

Revised OATT Attachment C submissions are procedures utilities use to coordinate with neighbouring systems. HQT has followed this approach in revising Attachment C-1 to its OATT.

25. HQT's ATC calculation methodology and information exchange or coordination procedures with neighbouring systems are not the same as some of the utilities' Attachment Cs that I have reviewed. They differ in one particular manner. Most of the AC systems in the U.S. that interconnect with each other regularly calculate ATCs across multiple interfaces simultaneously through the industry standard tool of load-flow analyses using the most up-to-date information on load levels, generation dispatch, and new transmission service requests. Because AC-interconnected systems act like a large pool with many ways for energy to flow, the ATC on one particular interface often can have an impact on the ATCs on other interfaces, including some that might be physically far away from each other.
26. HQT's interfaces with neighbouring systems are mostly DC interconnections, with controllable flows. In other words, the flow and therefore the ATC across HQT's interface with New England can be treated as independent of the ATC across HQT's interface with New York. This is not the case with other systems that are AC-interconnected.
27. Since the flow on each of HQT's DC interconnections with neighbouring systems is controllable and the ATC across one interconnection is independent from another interconnection, HQT does not require simultaneous modeling of all of its interfaces to determine the ATCs across each one. Thus, the most appropriate way for HQT to reflect FERC Order 890's requirement to have consistent ATCs with neighbouring systems across interfaces is to either adopt the neighbouring system's ATC or to request the neighbouring system to adopt HQT's ATC. I believe this is precisely what HQT attempts to achieve in its procedures outlined in its Attachment C-1.
28. The HQT approach has two notable features. First, since the ATC calculation does not rely on complex load flow calculations, the ATC calculation is very transparent. Second, the directness of the calculation avoids the necessity of potentially arguable assumptions

about the electrical system's capability that would be required for a load flow analysis. It represents an objective method for calculating ATC.

I have signed this report on June 23, 2010.

A handwritten signature in black ink, appearing to read 'P. Q. Hanser', is written over a solid horizontal line.

Philip Q Hanser

# **Attachment 1**

## **RESUME**

**Philip Q Hanser**

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**Mr. Philip Q Hanser** is a principal of *The Brattle Group* and has nearly thirty years of consulting and litigation experience in the energy industry. His expertise includes issues ranging from industry structure, market power and associated regulatory questions, to specific operational and strategic questions such as transmission pricing, generation planning, tariff strategies, fuels procurement, environmental issues, forecasting, demand-side management, and other management and financial issues. He has supported clients' efforts in insurance recovery of environmental liabilities arising from former manufactured gas plant sites, assessed liability risk in mass tort suits, and designed statistical database auditing procedures.

He has appeared as an expert witness before the U.S. Federal Energy Regulatory Commission (FERC), the California Energy Commission (CEC), the New Mexico Public Service Commission (NMPSC), the Public Service Commission of Wisconsin (PSCW), the Vermont Public Service Board (VPSB), the Public Utilities Commission of Nevada (PUCN), the Missouri Public Service Commission (MPSC), the Illinois Commerce Commission (ICC), the Régie de l'Énergie (Québec), the Ontario Energy Board, the Connecticut Siting Commission, the Pennsylvania Department of Environmental Protection, before arbitration panels, and in Federal and state courts. He served for six years on the American Statistical Association's Advisory Committee to the Energy Information Administration (EIA). He serves on CIGRE's (Conseil International des Grands Réseaux Electriques) Working Group C5-8, Working Group on Renewables and Energy Efficiency in a Deregulated Market. Prior to joining *The Brattle Group*, he served as the manager of the Demand-Side Management Program at the Electric Power Research Institute (EPRI). He has published widely in leading industry and economic journals. Mr. Hanser has taught at the University of the Pacific, University of California at Davis, and Columbia University, and guest lectured at the Massachusetts Institute of Technology, Stanford University, and the University of Chicago.

## **AREAS OF EXPERTISE**

- ♦ *Analysis of Electricity Generation, Contracts, and Wholesale Markets*
- ♦ *Resource Planning and Procurement*
- ♦ *Rate Design and Related Issues*
- ♦ *Environment*
- ♦ *Energy Efficiency, Demand-Side Management, and Renewables*
- ♦ *Analysis of Market Power*
- ♦ *RTO Design and Participation*
- ♦ *Forecasting and Weather Normalization*
- ♦ *Transmission*
- ♦ *Plant Performance and Strategy*

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**EXPERIENCE***Analysis of Electricity Generation, Contracts, and Wholesale Markets*

- ◆ Provided expert testimony in Massachusetts State Court on the impacts of alleged violations of a wholesale power contract on a supplier in ISO-NE.
- ◆ For the California Department of Water Resources provided expert testimony in federal bankruptcy court with regard to the public interest standard to be applied to Calpine Corporation's rejection of its contracts. This assignment included a valuation of the contract over time through the use of a simulation model of the California market, as well as an assessment of the potential reliability implications for the California market.
- ◆ For the California Department of Water Resources and the California Attorney General's Office, provided expert testimony on damages resulting from Sempra Energy Resources breaches of its power purchase agreement in both arbitration hearings and California state court. Analyzed two years of hourly data on energy deliveries, market prices, ISO charges, and invoice charges to identify and evaluate performance violations and invoice overcharges. Assisted counsel in developing the theory of the case and provided general litigation support in preparation for and during arbitration.
- ◆ For Dominion Electric Marketing, Inc. (DEMI), provided assistance in their response to a complaint by United Illuminating (UI) regarding their wholesale supply contract. The dispute centered on the allocation of reliability must run costs between UI as a load-serving entity and DEMI as wholesale supplier.
- ◆ For the California Department of Water Resources critically reviewed the California ISO's proposed implementation of locational marginal pricing (LMP) and analyzed implications for "seller's choice" supply contracts. Developed a framework for quantifying the incremental congestion costs that ratepayers would face if suppliers financially delivered power to the lowest priced nodes; estimated potential incremental contract costs using a third party's GE-MAPS market simulations (and helped to improve their model inputs to more accurately reflect the transmission system in California). Made recommendations to the CAISO as to how to address the issue.
- ◆ Provided expert testimony in Massachusetts state court on the damages incurred by a power plant developer as a result of alleged contractual violations by a supplier for a plant constructed in ISO-NE.

- ◆ For a Florida utility, provided a confidential expert report evaluating the benefits of the power from a co-generator and its potential rate implications, and assisted in the negotiation of a co-generation contract with a large industrial customer.
- ◆ Assisted a U.S. electric utility in the preparation of a bid proposal to an industrial firm for the leasing of a new power plant. The assignment included risk analysis of the proposal, assessment of financial and rate impacts, and market assessment of competitors' potential offerings.

### *Resource Planning and Procurement*

- ◆ For the Edison Electric Institute, co-authored a report on the general inapplicability of standard financial portfolio theory to the resource portfolios of utilities.
- ◆ For the investor-owned utilities of Wisconsin, provided testimony before the Public Service Commission of Wisconsin on cost of capital issues for use in its statewide resource planning exercise.
- ◆ For an international development bank, evaluated generation resource needs for an Eastern European country as well as a determination of alternative means to meet those generation needs. This assignment included analysis of the impact of privatization on the country's economy, its import and export sectors, and future development of electricity and gas resources.

### *Environment*

- ◆ For an Eastern utility with substantial coal-generating facilities, provided advice with regard to maintenance procedures and risk exposure to New Source Review standards under the Clean Air Act Amendments.
- ◆ For a Western generator with substantial coal-generating facilities he has provided assistance with regard to responding to allegations by the Environmental Protection Agency of failure to comply with the New Source Review standards under the Clean Air Act Amendments.
- ◆ For Illinois Power Company, provided expert testimony in federal court on the regulatory and rate base implications of the Clean Air Act Amendments, in support of the calculation of noncompliance economic damages arising from New Source Review.
- ◆ For a gas utility, assisted in the development of potential manufactured gas liabilities for use in insurance recovery and in estimating potential recovery under a variety of insurance allocation theories and estimated the risk distribution of the estimates.

- ◆ For a gas utility, assisted in the assessment of the announcement effect of environmental liabilities on its cost of capital. This assignment included estimation of changes in market betas for pre- and post- environmental liability announcement.

#### *Energy Efficiency, Demand-Side Management, and Renewables*

- ◆ For a large utility in the Southern United States, prepared expert report investigating alternative cost allocation approaches for generation capacity, fuel, and demand-side management (DSM) costs both through a review of the methods and surveys of practice.
- ◆ For Central Vermont Public Service, provided expert testimony on the impact of its demand-side management programs before the Vermont Public Service Board.
- ◆ For Ameren/UE's Illinois subsidiaries, provided expert testimony on the potential for gas demand-side management and resulting potential rate implications.
- ◆ For a Northeast utility developed an assessment of the potential penetration rate of microturbines. For the utility service territories under consideration, evaluated the back-up generation rates and connection charges likely to be incurred for such systems to determine customer costs and benefits.
- ◆ For a utility located in WECC procuring renewable resources, provided a system integration study for a range of renewable project proposals. Used production costing and power flow models to estimate the "deliverability" of various proposals, including estimating the LMP prices and the potential congestion costs. Ranked the proposed renewable power projects by their estimated benefits and costs, and delivered a formal presentation at the completion of the project.
- ◆ For a power marketer and developer of independent power projects in Great Britain, assisted in the preparation of comments on proposals by the UK pool regarding the role of demand-side bidding and the pricing of transmission losses.
- ◆ For a Texas utility, provided expert testimony regarding breach of contract claims made against it by an industrial participant in an energy efficiency project. Reviewed the energy efficiency impacts of program. Calculated the net present value of the project in relation to various rate options and market prices.
- ◆ For Connecticut Light and Power, provided testimony in support of an application for a Certificate of Environmental Compatibility and Public Need for the construction of a 345-kV electric transmission line and reconstruction of an existing 115-kV electric transmission line. At issue was the use of distributed resources to substitute for the proposed lines.

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*Analysis of Market Power*

- ◆ For the California Parties, provided litigation support and testimony regarding manipulation of energy and ancillary service market prices and the outage behavior of gas fired power plants during 2000-01. The proceeding, before the Federal Energy Regulatory Commission involved Enron, Dynegy, Mirant, Reliant, Williams, and other suppliers in the U.S. and Canada. The analyses focused on the use by suppliers of generation outages to affect market prices through physical withholding, as well as the use of pricing to yield economic withholding.
- ◆ For the California Parties, provided litigation support and testimony regarding Enron's transmission and ancillary services market manipulation strategies, including 'Death Star' and 'Get Shorty.'
- ◆ For Southern California Edison, submitted testimony before the FERC describing the implications for the electricity market of the manipulation of gas market prices.
- ◆ For Sierra Pacific Resources Company, provided expert testimony before the Public Utilities Commission of Nevada and the FERC regarding the market power implications of generation asset divestiture required for the merger of Sierra Pacific Power and Nevada Power Company. Developed a Cournot market model to assess the market power implications of selling off alternative groupings of generation.
- ◆ For the Pennsylvania-New Jersey-Maryland Interconnection, LLC (PJM) co-authored annual report on the state of its markets. The report included an assessment of the market's competitiveness and potential structural deficiencies, and identified potential instances of market abuse.
- ◆ For PJM, developed an ensemble of metrics for assessing market power in its markets. The metrics included an early warning system to permit PJM interventions into market abuse at the earliest possible stage.
- ◆ For PJM, developed software for unilateral market power assessment and assisted PJM in its preliminary implementation. Its use was demonstrated with an incident involving potential market power abuse by PJM members.

*RTO Design and Participation*

- ◆ For Northeast Utilities provided testimony before the FERC with regard to the economics of imposing local installed capacity (LICAP) requirements on ISO-NE. Also has provided expert testimony before the FERC in support of its applications for market-based rate authority.

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- ◆ For NSTAR provided testimony before the FERC on several matters including the necessity of imposing bid caps on the New England electricity market, replacement energy rates for generators when transfer capability into a transmission-constrained zone was reduced because of system upgrades, and the appropriateness of granting market-based rate authority to a generator in a transmission-constrained zone. Developed a Cournot market model to forecast the potential impact on market prices in the transmission-constrained zone that the majority of NSTAR's service territory is located.
  
  - ◆ For Nevada Power Company, provided expert testimony before the FERC for its market-based rate authority application.
  
  - ◆ For Otter Tail Power Company, provided an affidavit to the FERC assessing how the Midwest ISO's proposed Transmission and Energy Market Tariff would affect Otter Tail Power both operationally and financially. Based on the strategies that were pursued by some market participants during the 2001 California electricity market crisis, demonstrated the potential to pursue similar strategies in MISO and harm Otter Tail and its customers.
  
  - ◆ For Edison Mission Energy's subsidiary Midwest Gen, provided expert testimony to the FERC for its market-based rate authority application.
  
  - ◆ For a Midwest utility, examined the implications of differing configurations of the independent system operator on potential market power concerns. The issue particularly examined was the question of seams and how different ISO configurations affected the costs of transactions.
  
  - ◆ Co-authored a report for the New York Independent System Operator's (NYISO) assessing the reliability implications of modifying its rules regarding installed capacity.
  
  - ◆ Submitted testimony to the Public Utilities Commission of Texas (PUCT) regarding a proposed rule to allocate costs of procuring replacement reserves to market participants in ERCOT. The proposed rule required ERCOT to assign the majority of such costs directly to market participants who relied on ERCOT's balancing energy (*i.e.*, real-time energy) market. However, a review of the market rules and the historical evidence indicated that the majority of the procurement of replacement reserves was not caused by this behavior. The PUCT rejected the proposed cost allocation rule, and instead required ERCOT to uplift the replacement reserve costs based on the load ratio shares of market participants until the implementation of a reasonable allocation rule or the start of the Texas Nodal Market.
  
  - ◆ For the Edison Electric Institute, authored a report on standard market design and its implications for utilities within regional transmission organizations.

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### *Forecasting and Weather Normalization*

- ◆ For Florida Power and Light Co., provided testimony before the Florida Public Service Commission with regard to its forecasting methodology.
- ◆ For an electric utility in the Southeast, reviewed the existing weather normalization process and diagnosed problems with weather data and regression model. Developed alternative daily and monthly normalization models, improved degree day specification, selection of weather stations, and regression specification to double prediction accuracy and improve stability of normalization process.
- ◆ For PJM, conducted a comprehensive review of its models for forecasting peak demand and re-estimated new models to validate recommendations. Individual models were developed for 18 transmission zones as well as a model for the entire PJM system.
- ◆ For a Southwestern utility, developed models for forecasting monthly sales and loads for the residential, commercial and industrial customer classes using primary data on customer loads, weather conditions and economic activity.
- ◆ For the Public Service Company of New Mexico, provided expert testimony before the Public Utilities Commission of New Mexico regarding the forecasted growth of the El Paso, Texas and Juarez, Mexico markets and their electricity requirements.
- ◆ For a Southeastern utility, developed a model for forecasting monthly demand that incorporated the impacts of its significantly declining housing market and which served the basis for its treasurer's revenue forecast.

### *Rate Design and Related Issues*

- ◆ For intervenors in Toronto Hydro Electric System Limited (THESL), provided testimony on cost allocation issues with regard to THESL's suite metering program.
- ◆ For Ameren/UE's Missouri subsidiary, provided expert testimony on its rate design before the Missouri Public Utility Commission. Assisted the development of company witnesses' rationale for the choice of cost of service allocation method, developed benchmarks for the rate increase against similarly situated utilities, as well for other commodities' escalations, and evaluated proposed demand-side management programs and rate options.
- ◆ For Ameren/UE's Illinois subsidiaries, provided expert testimony on the potential for gas

demand-side management. The testimony discussed potential rate implications of such programs on the revenue of the utilities.

- ◆ For the Edison Electric Institute, co-authored a series of papers with regard to issues facing utilities. The reports covered the issues of fuel adjustment clauses, mitigating large rate increase impacts, and the Energy Policy Act of 2005.
- ◆ For a U.S. electric utility, assisted in the valuation of generation assets for use in its testimony on stranded costs. This included development a financial model to determine the generation assets' market value, development of a convolution algorithm to convert market scenarios into a probability distribution of asset values, and statistical analysis of the relationship of the utility's generation assets' operating costs in comparison to its competitors. The assignment also included testimony preparation, interrogatories, and rebuttals.
- ◆ For the City of Vernon submitted testimony to the FERC regarding its revenue requirements for transmission.

### *Transmission*

- ◆ Before staff members of the FERC, assisted in the development of a review of the implications of the restructuring in transmission assets' cost of capital.
- ◆ For a power marketer and developer of independent power projects in Great Britain, assisted in the preparation of comments on proposals by the UK pool regarding the pricing of transmission losses and the role of demand-side bidding.
- ◆ For a European transmission company, provided an analysis of the likely development of the European electricity market. Also assessed market implications for the transmission company of modifications to the transmission grid.
- ◆ For Hydro Québec, provided expert testimony before the Régie d'Énergie regarding whether a set of privately held transmission facilities constituted a looped transmission system and, thus, was subject to requests for transmission service.

### *Plant Performance and Strategy*

- ◆ For the Keystone-Conemaugh Project Office, performed a benchmarking analysis to identify the areas in which Keystone and Conemaugh coal units were better performing or under-performing compared to other units with similar characteristics. This involved comparing the historical operational and cost performance of the Keystone and Conemaugh coal units against their peer groups; identifying the areas where the performance of the Keystone and Conemaugh coal units

were above and below the average quartile of their peer groups; and developing metrics and methodologies to combine the results of individual comparisons across the operational and cost performance assessments.

- ◆ For a U.S. electric utility, assisted in the development of a legislative and regulatory strategy with regard to restructuring. This assignment included generation asset valuation in a competitive market, development of stand-alone transmission and distribution rates under cost-of-service and performance-based regulation, and estimation of stranded costs.

### *Other energy experience*

- ◆ For the Edison Electric Institute, conducted Pre-Course Workshop for Electric Rate Advanced Course, “Traditional Embedded Costing and Pricing Concepts,” University of Wisconsin, Madison, July 26, 2009.
- ◆ For the Edison Electric Institute, conducted workshop for Electric Rate Advanced Course, “Unbundling Methodologies”, University of Wisconsin, Madison, July 26, 2009.
- ◆ For the Edison Electric Institute, conducted webinar “Long-Term Energy Forecasts: Challenges and Approaches,” June 17, 2009.
- ◆ For the Indiana Energy Conference, presented “It Ain’t Your Father’s IRP, Meeting Today’s Challenges,” October 2, 2008
- ◆ For the NEPOOL Forecasting Committee Summer Meeting, presented “I’m a Forecaster – And You Can Too!” July 17, 2008
- ◆ For the Electric Power Research Institute (EPRI), developed and directed a research program to provide electric utilities the following capabilities: marketing research, pricing and rate design, integrated resource planning, capital budgeting, environmental impacts of electric utilities and end-use technologies, load research, forecasting, and demand-side management through software tools, database development and technology development. Assisted in the development of the Load Management Strategy Testing Model (LMSTM), enhancements to the Electric Generation Expansion Analysis Model (EGEAS). Co-wrote reports on the environmental impacts of electric technologies, environmental externalities, cost-benefit analysis of evaluation of DSM programs, rate design and costing, integrated resource planning, impacts of interruptible and curtailable loads, product differentiation, activity-based costing, DSM program evaluation, and others. Served as project manager of the Edison Electric Institute (EEI), National Rural Electric Cooperatives Association (NRECA), American Public Power Association (APPA), and National Association of Regulatory Utility Commissioners (NARUC) jointly sponsored Electric Utility Rate Design Study (EURDS). Represented the Institute before various regulatory commissions, Federal agencies, and utility executives. He served on the Environmental Protection Agency’s advisory committee for the Clean Air Act Amendments. He also served as the operating agent

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for Annex IV, Improved Methods for Integrating Demand-Side Options into Utility Resource Planning, of the International Energy Agency Agreement on Demand-Side Management.

- ◆ For a California utility, supervised short- and long-term forecasts of sales and peak demand for use in resource and corporate planning. Supervised and helped prepare forecast documentation for public hearings before the California Energy Commission and represented the utility to the Commission on the forecast. Supervised the design and implementation of long-term strategic planning and financial models, and prepared both marginal and embedded cost of service studies for the utility and assisted in their use for the design of customer rates. Evaluated the impact of energy conservation programs and legislation on long-term system resource requirements. Designed and implemented the residential survey of appliance holdings and commercial customer equipment survey.

### *Non-energy Related*

- ◆ Submitted testimony in bankruptcy court regarding the estimation of inventory subject to reclamation by a wholesale pharmaceuticals supplier which was sold to a bankrupt retail drug chain. The retail chain failed to maintain proper inventory records and a statistical approach which used a combination of data on overall inventory and the shipment and replenishment records of the supplier was used to develop the estimate.
- ◆ Designed a statistically valid database sampling procedure for assessing the validity of insurance claims arising from mass tort actions. The database contained summary information on the claims and for each claim there was, at times, voluminous information on the individual cases. The sampling procedure was used to determine which records would be chosen and assessed the individual's claim eligibility.
- ◆ Assessed the liability risk of an insurance company that provided coverage relevant to a mass tort suit. A Markov chain model was developed to estimate the size of the potential population and then a risk model was developed to calculate potential exposure.

### **TESTIMONY AND REGULATORY FILINGS**

Before the Commonwealth of Massachusetts Trial Court, in the matter of MASSPOWER v. Massachusetts Municipal Wholesale Electric Company (MMWEC), Civil Case No. 07-3243 BLS2; Testified on behalf of MMWEC regarding the management and ownership of investor-owned utilities ("IOUs"), MMWEC, and municipal light departments ("Municipals") in Massachusetts before and after the passage of the Electric Industry Restructuring Act of 1997, as well as the impact of electric industry restructuring in Massachusetts on IOUs, MMWEC, and Municipals with respect to contract buyouts, March 2010.

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Before the Ontario Energy Board, in the matter of Toronto Hydro-Electric System Limited's 2010 Electricity Distribution Rate Application, Prepared Witness Statement on Behalf of the Smart Sub-Metering Working Group, December 15, 2009.

Before the Office of the Attorney General of the State of California, prepared Second Addendum Report to Expert Report of Philip Q Hanser on Behalf of California Department of Water Resources, Case No. GIC 789291, September 30, 2009.

Before the Florida Public Service Commission on Behalf of Florida Power and Light Company, prepared Rebuttal Testimony of Philip Q Hanser, Docket No. 080677-EI, August 6, 2009.

Before the Federal Energy Regulatory Commission on Behalf of the City of Vernon, California, prepared Petition for Declaratory Order and Request for Waiver of Filing Fee of City of Vernon, California, Docket No. EL09-\_\_\_-000, July 15, 2009

Before the Régie De L'Énergie, prepared Supplemental Expert Report of Philip Q Hanser on Behalf of Hydro-Québec TransÉnergie, in response to Newfoundland and Labrador Hydro's complaint P-110-1692, June 2009.

Before the Federal Energy Regulatory Commission, on Behalf of The People of the State of California, *ex rel.* Edmund G. Brown Jr., Docket No. EL09-\_\_\_ (filed May 22, 2009) ("Brown Complaint"), filed direct testimony regarding emergency purchases the State authorized the California Energy Resources Scheduling division of the California Department of Water Resources ("CERS") to make when the California investor-owned utilities (IOUs) could not purchase the power needed to serve their customers.

Before the Florida Public Service Commission on Behalf of Florida Power and Light Company, prepared Direct Testimony of Philip Q Hanser, Docket No. 080677-EI, April 23, 2009.

Before the Office of the Attorney General of the State of California, prepared Addendum to Expert Report of Philip Q Hanser on Behalf of California Department of Water Resources, Case No. GIC 789291, March 31, 2009.

Before the Pennsylvania Public Utility Commission on Behalf of Pennsylvania Electric Company, prepared Rebuttal Testimony of Philip Q Hanser and Metin Celebi concerning the Causes and Pricing of Transmission Congestion, Docket No. P-2008-2020257, January 16, 2009.

Before the Régie De L'Énergie, prepared Expert Report of Philip Q Hanser on Behalf of Hydro-Québec TransÉnergie, in response to Newfoundland and Labrador Hydro's complaints P-110-1565, P-110-1566, P-110-1597, P-110-1678, and P-110-1692, December 2008.

Before the Pennsylvania Public Utility Commission, Docket No. P-2008-2020257, prepared testimony on behalf of Wellsboro Electric Company concerning the causes and pricing of transmission congestion, July 30, 2008.

Before the Régie De L'Énergie, Prepared Affidavit on Behalf of Hydro-Québec regarding the public availability of SIS reports performed by a transmission provider, June 19, 2008.

Before the Federal Energy Regulatory Commission, Docket No. EL08-\_\_\_-000, Prepared Direct Testimony on Behalf of the City of Vernon's revised TRR filing with the FERC, April 3, 2008.

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Before the Régie De L'Énergie, Prepared Expert Report on Behalf of Hydro-Québec TransÉnergie to assess whether the transmission facilities owned by ELL may be considered as a "radial generator lead", Case No. R-3636-2007, March 13, 2008.

Before the American Arbitration Association, Case No. 74Y1980019606MAVI, Prepared Rebuttal Report on Behalf of the California Department of Water Resources to evaluate the reports that William Hogan, Jeffrey Tranen, and Ellen Wolfe provided on behalf of Sempra Generation, June 4, 2007.

Before the American Arbitration Association, Case No. 74Y1980019606MAVI, Prepared Expert Report on Behalf of the California Department of Water Resources to evaluate certain claims made by the California Department of Water Resources ("DWR") in its Demand for Arbitration regarding the performance of Sempra Energy Resources, now known as Sempra Generation, under the Energy Purchase Agreement between the parties, and to calculate amounts that Sempra would owe to DWR assuming liability is established, May 14, 2007.

Before the United States Bankruptcy Court, Northern District of Ohio, Eastern Division, Case Nos. 01-44007 through 01-44015, Expert Report in regard to McKesson's inventory reclamation in the Phar-Mor bankruptcy, March 9, 2007.

Before the Public Utility Commission of Texas, Docket No. 33416, Prepared Rebuttal Testimony on Behalf of Constellation New Energy, Inc.'s appeal and complaint of ERCOT decision to approve PRR 676, PRR 674 and request for expedited relief, January 11, 2007.

Before the Public Utility Commission of Texas, Docket No. 33416, Prepared Direct Testimony on Behalf of Constellation NewEnergy, Inc. to analyze and discuss the flaws and potential negative impacts of the allocation methods under Protocol Revision Request ("PRR") 676 which relates to procurement costs for Replacement Reserve Service ("RPRS") and Out of Merit Capacity, November 22, 2006.

Before the American Arbitration Association, Case No. GIC 789291, Prepared Rebuttal Report on Behalf of California Department of Water Resources vs. Sempra Energy Resources, July 11, 2006.

Before the State Office of Administrative Hearings, Prepared Expert Report on Behalf of TXU Energy Solutions, regarding their demand-side management program and the difference between the actual and projected savings in the energy bill of University of Texas, July 7, 2006.

Before the Missouri Public Service Commission, Case No. ER-2007-0002, Prepared Direct Testimony on Behalf of Union Electric Company with regard to Ameren UE's rate design proposals, July 5, 2006.

Before the American Arbitration Association, Case No. GIC 789291, Prepared Expert Report on Behalf of California Department of Water Resources vs. Sempra Energy Resources, June 9, 2006.

Before the Superior Court of the State of California, J.C.C.P. Nos. 4221, 4224, 4226 and 4228, Prepared Declaration in support of California State Agencies' opposition to motion on shortened time and motion in support of preliminary approval of class action settlement, June 8, 2006.

Before the Superior Court of the State of California, J.C.C.P. Nos. 4221, 4224, 4226 and 4228, Prepared Declaration in support of California State Agencies' opposition to proposed publication notice, January 13, 2006.

Before the United States Bankruptcy Court, Case No. 05-60200 (BRL), Prepared Declaration on Behalf of Calpine Corporation with regard to the public interest standard for the rejection of the contract, December 30, 2005.

Before the FERC, Docket No. EL05-76-001, Prepared Direct Testimony on Behalf of Dominion Energy Marketing, Inc. (DEMI), regarding a dispute between DEMI and The United Illuminating Company as to which party is responsible for paying certain costs associated with Reliability Must-Ran agreements under a December 28, 2001 Power Supply Agreement between the two parties, December 5, 2005.

Before the American Arbitration Association, Case No. 74Y1980019304VSS, Prepared Expert Report on Behalf of California Department of Water Resources vs. Sempra Energy Resources with regard to damages from multiple contract breaches, May 2005.

Before the FERC, Docket No. EL03-180-000, Prepared Supplemental Testimony on Behalf of the California Parties with regard to Enron's circular scheduling and paper trading gaming practices, January 31, 2005.

Before the FERC, Docket No. ER96-496-010, *et al.*, Prepared Affidavit on Behalf of Northeast Utilities Service Company and affiliated companies market-based rate authorization, September 27, 2004, Revised December 9, 2004.

Before the Connecticut Siting Board, Docket 217, Prepared Testimony on Behalf of Connecticut Light and Power in support of its application for a Certificate of Environmental Compatibility and Public Need for the construction of a 345-kV electric transmission line and reconstruction of an existing 115-kV electric transmission line between Connecticut Light and Power Company's Plumtree Substation in Bethel, through the Towns of Redding, Weston, and Wilton, and to Norwalk Substation in Norwalk, Connecticut, November, 2004.

Before the FERC, Docket No. ER04-691-000, Prepared Affidavit on Behalf of Otter Tail Power Company (OTP) regarding problems that may result from the implementation of MISO's markets tariff in OTP's region, May 7, 2004.

Before the FERC, Docket No. ER03-563-030, Prepared Joint Affidavit with Judy W. Chang on Behalf of Devon Power LLC, *et al.*, March 24, 2004.

Before the FERC, Docket No. EL03-180-000, Prepared Direct Testimony on Behalf of the California Parties with regard to Enron's circular scheduling and paper trading gaming practices, February 27, 2004

Before the Commonwealth of Massachusetts, Case No. 99-6016, Prepared Expert Report on Behalf of Alstom Corporation and Black and Veatch vs. Meriden Corporation, LLC, Review of "*Value of the Meriden Power Project*", January 9, 2004

Before the FERC, Docket No. EL03-159-000, Prepared Declaration on Behalf of The California Parties, Re: Gaming Activities Of Modesto Irrigation District, October, 2003.

Before the FERC, Docket No. ER03-118-000, Prepared Affidavit on Behalf of Otter Tail Power Company For Otter Tail Power Company, assessing how the Midwest ISO's proposed Transmission and Energy Market Tariff will affect Otter Tail Power both operationally and financially, September 15, 2003.

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Before the Pennsylvania Environmental Hearing Board, New Jersey Department of Environmental Protection vs. Pennsylvania Department of Environmental Protection and Lower Mount Bethel Energy, LLC, Docket No. 2001-280-C, Prepared Expert Report on Behalf of Pennsylvania Power and Light, May 2, 2003.

Before the FERC, Docket No. EL00-95-069, Prepared Rebuttal Testimony on Behalf of Southern California Edison for the California Parties regarding manipulation of energy and ancillary service market prices and the outage behavior of gas fired power plants, March 20, 2003.

Before the FERC, Docket No. EL00-95-069, Prepared Testimony on Behalf of Southern California Edison for the California Parties regarding manipulation of energy and ancillary service market prices and the outage behavior of gas fired power plants, February 24, 2003.

Before Southern District Court of Illinois, Docket No.99-833-MBR, Prepared Expert Report for Department of Justice, Environmental Protection Agency vs. Illinois Power Company and Dynegy Midwest Generation regarding the likely rate treatment of, July 29, 2002.

Before the FERC, Docket No. ER99-3693-000, Prepared Direct Testimony on Behalf of Edison Mission Energy and Edison Mission Marketing and Trading, Inc. on behalf of Midwest Generation's application for market-based rate authority, April 1, 2002.

Before the FERC, Docket No. ER01-890-000, Prepared Rebuttal Testimony on Behalf of NSTAR on the appropriate rates for generators during transmission upgrades or enhancements requiring substantial and sustained reduction in transfer capability, September 21, 2001.

Before the FERC, Docket No. EL01-79-000, Prepared affidavit on Behalf of NSTAR, in their intervention of the granting of market-based rate authority to Sithe, May 2001.

Before the FERC and the Public Utilities Commission of Nevada, Docket No. EC0-173-000, Prepared Affidavit on Behalf of Sierra Pacific Resources Company, regarding the market power implication of generation asset divestiture required for the merger of Sierra Pacific Power and Nevada Power Company, February 23, 2001.

Before the California Energy Commission, Prepared Expert Report on Behalf of Calpine Corporation; Socioeconomic Resources: Economic Benefits of the Metcalf Energy Center, October 27, 2000.

Before the FERC, Docket No. EL00-83-000, Prepared Affidavit on Behalf of NSTAR with regard to the necessity of imposing bid caps on the New England electricity market, June 23, 2000.

Before the FERC, Docket No. ER99-2338-001, Prepared Direct Testimony on Behalf of Nevada Power Company in support of the divestiture of its generation assets, June 24, 1999.

Before the FERC, Docket No. ER99-2338-001, Prepared Direct Testimony on Behalf of Nevada Power Company in support of the divestiture of its generation assets, March 30, 1999.

Before the Vermont Public Service Board, Docket No. 6018, Prepared Rebuttal Testimony on Behalf of Central Vermont Public Service Corporation on the impact of its demand-side management programs, April 10, 1998.

Before the New Mexico Public Utility Commission, Case No. 2769, Prepared Direct Testimony prepared on Behalf of the Public Service Company of New Mexico regarding forecasted growth of the El Paso and Juarez, Mexico markets, 1997.

Before the Public Service Commission of Wisconsin, Docket No. 05-EP-7, Prepared Direct Testimony on Behalf of investor-owned utilities of Wisconsin on the utilities cost of capital, May 8, 1995.

Before the FERC, Docket No. RP95-363-015, Prepared Affidavit on Behalf of Southern California Edison describing the implications for the electricity market of the manipulation of gas market prices.

### ACADEMIC HISTORY

Guest Lecturer, Energy Laboratory Short Courses, Massachusetts Institute of Technology, Cambridge, MA	1997-1998
Visiting Lecturer, Department of Economics, University of California, Davis; Davis, CA	1981-1982
Assistant Professor, Departments of Economics and Mathematics, University of the Pacific, Stockton, CA	1975-1980
Ph.D. Candidacy Requirements Completed, Columbia University, NY	1975
Phil.M. (Economics and Mathematical Statistics) Columbia University	1975
A.B. (Economics and Mathematics) The Florida State University, FL	1971
Time Series and Econometric Forecasting, University of California at Berkeley Engineering Extension Course	September 1979
Data Analysis and Regression, American Statistical Association Short Course, San Diego, CA	August 1978

### PROFESSIONAL RELATIONSHIPS

<i>American Statistical Association</i>	1974-current
Member of Committee on Energy Statistics	1993-1999
<i>The Brattle Group</i>	<a href="http://www.brattle.com">www.brattle.com</a>

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<i>Institute of Electrical and Electronics Engineer</i>	1986-current
<i>Association of Energy Service Professionals</i> , Board Member	1991-1995
<i>Journal of ADSMP</i> , Editor	1995
<i>American Economic Association</i>	Present
<i>Northeast Energy and Commerce Association</i>	Present
<i>National Association of Regulatory Commissioners</i>	Present

### HONORS

Teaching Incentive Award, University of the Pacific	1979
Teaching Assistantship in Econometrics, Columbia University	1974
National Science Foundation Research Traineeship	1972 – 1974
Undergraduate and Graduate Research Assistantships, Florida State University	1968 – 1972
Omicron Delta Epsilon, Economics Honor Society	1971

### PUBLICATIONS AND PRESENTED PAPERS

“Utility Supply Portfolio Diversity Requirements” (with Frank Graves), *The Electricity Journal*, Vol. 20, Issue 5, June 2007.

“Electric Utility Automatic Adjustment Clauses Revisited: Why They Are Needed More Than Ever” (with Frank Graves and Greg Basheda), *The Electricity Journal*, Vol. 20, Issue 5, June 2007.

“Rate Shock Relief” (with Frank Graves and Greg Basheda), *Electric Perspectives*, May/June 2007.

“Rate Shock Mitigation” (with Frank Graves and Greg Basheda), prepared for Edison Electric Institute, May 2007.

“Wire We Here? Coal in the West,” Law Seminars International, Coal in the West Conference, Denver, Colorado, March 30, 2007.

“Electric Utility Automatic Adjustment Clauses: Benefits and Design Considerations” (with Frank Graves and Greg Basheda), Edison Electric Institute, August 2006.

*The Brattle Group*

www.brattle.com

“Can Wind Work In An LMP Market?” (with Serena Hesmondhalgh and Dan Harris), *Natural Gas & Electricity*, November 2005.

“The CAISO’S Physical Validation Settlement Service: A Useful Tool for All LMP-Based Markets” (with Jared S. des Rosiers, Metin Celebi, Joseph B. Wharton), *The Electricity Journal*, September 2005.

“Does SMD Need a New Generation of Market Models? Or How I Learned to Stop Worrying and Enjoy Carrying a Pocket Protector,” SMD Conference, Washington, D.C., December 5, 2002.

“A Summary of FERC’s Standard Market Design NOPR,” Edison Electric Institute, August 2002.

“Standard Market Design in the Electric Market: Some Cautionary Thoughts,” SMD Conference, May 10, 2002, Chicago, Illinois.

“The Design of Tests for Horizontal Market Power in Market-Based Rate Proceedings” (with James Bohn and Metin Celebi), *The Electricity Journal*, May 2002.

“The State of Performance-Based Regulation in the U.S. Electric Industry” (with D.E.M. Sappington, J.P. Pfeifenberger, and G.N. Basheda), *The Electricity Journal*, October 2001.

“Deregulation and Monitoring of Electric Power Markets” (with R.L.Earle and J.D. Reitzes), *The Electricity Journal*, October 2000.

“Shortening the NYISO’s Installed Capacity Procurement Period: Assessment of Reliability Impacts,” NYISO, May 2000.

“PJM Market Competition Evaluation White Paper,” (with Frank C. Graves), prepared for PJM, L.L.C., October 1998.

“Lessons from the First Year of Competition in the California Electricity Market” (with R.L.Earle, W.C. Johnson, and J.D. Reitzes), *The Electricity Journal*, October 1999.

Comments to the FERC concerning Regional Transmission Organizations Notice of Proposed Rule Making, RM99-2, (with Peter Fox-Penner), September 17, 1999.

“In What Shape is Your ISO?” (with J.P. Pfeifenberger, G.M. Basheda and P.S. Fox-Penner), *The Electricity Journal*, Vol. 11, No. 6, July 1998.

“What’s in the Cards for Distributed Resources?” (with J. P. Pfeifenberger and P.R. Ammann), in Special Issue of *The Energy Journal*, *Distributed Resources: Towards a New Paradigm of the Electricity Business*, January 1998.

“One-Part Markets for Electric Power: Ensuring the Benefits of Competition” (with F.C. Graves, E.G. Read, and R.L. Earle), in *Power Systems Restructuring: Engineering and Economics*, ed. M. Ilic, F. Galiana, and L. Fink, (Boston, MA: Kluwer Academic Publishers, 1998)

“Power Market Price Forecasting: Pitfalls and Unresolved Issues” (with R.L. Earle and F.C. Graves), forthcoming in *The Energy Journal*.

Ten EPRI reports and approximately 20 articles in EPRI Reports and Conference Proceedings.

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“Insurance Recovery for Manufactured Gas Plant Liabilities” (with G.S. Koch and K.T. Wise), *Public Utilities Fortnightly*, April 1997.

“Real-Time Pricing - Restructuring’s Big Bang?” (with J.B. Wharton and P. Fox-Penner), *Public Utilities Fortnightly*, March 1997.

“Load Impact of Interruptible and Curtailable Rate Programs” (with D.W. Caves, J.A. Herriges, and R.J. Windle), *IEEE Transactions on Power Systems*, Vol. 3, No. 4, November 1988.

“Estimating Hourly Electric Load with Generalized Least Squares Procedures” (With N. Toyama and C.K. Woo.), *The Energy Journal*, April 1986.

“Transfer Function Estimation Using TARIMA,” *SAS User’s Group International, 1982 Proceedings*. Cary, North Carolina: SAS Institute. Inc., 1982.

“Invited Editorial Response to Behavioral Community Psychology: Integrations and Commitments,” by Richard Winett, *The Behavior Therapist* 4(5), Convention, 1981.

*Statistics Through Laboratory Experiences* (with D. Christianson and D. Hughes), Stockton, CA: University of the Pacific 1976-1977.

“Unsolved Advanced Problem,” *American Mathematical Monthly*, May 1975.

“Multiattribute Utility Theory and Earthquake Mitigation Policy” (with T. Munroe), Western Economic Association Conference, June 1978.

“Introduction to Multivariate Data Analysis Techniques,” Bureau of Applied Social Research, Columbia University, New York, NY, 1973.

## **Attachment 2**

**ATTACHMENT C-1 TO HQT'S OATT**

ATTACHMENT C-1Methodology for Estimating Available Transfer Capability

This Attachment C-1 replaces Attachment C as of the date set forth in Section 44.2 of this Tariff to this effect.

The Transmission Provider offers Point-to-Point Transmission Service over its interconnections with neighboring systems. Data on the transfer capability of interconnections for given periods in the future is posted on the Transmission Provider's OASIS site. Each interconnection is indicated as a path linked to point HQT, which represents all Points of Receipt on the Transmission Provider's system, except the interconnections themselves.

The following guidelines and principles are applied to assess Available Transfer Capability (ATC):

- (a) Good Utility Practice;
- (b) Northeast Power Coordinating Council (NPCC), North American Electric Reliability Corporation (NERC) and North American Energy Standards Board (NAESB) criteria and guidelines; and
- (c) Applicable Transmission Provider criteria and guidelines

Available Transfer Capability is the portion of Total Transfer Capability (TTC) that is unused after consideration of Transmission Reliability Margin (TRM) and requirements to:

- (a) meet obligations of existing Transmission Service for the delivery of resources to Native-Load Customers;
- (b) meet obligations of existing contracts under which Transmission Service is provided; and
- (c) meet obligations of accepted Applications for Transmission Service.

For interconnections where firm transfer capability is coordinated between the Transmission Provider's system and a neighbouring system, such capability corresponds to the lower of the following capacity values: (1) firm capacity to receive (or deliver) power before the ETCs of the neighbouring system are taken into account, and (2) firm capacity to receive (or deliver) power before the ETCs of the Transmission Provider are taken into account.

Non-firm transfer capability offered by the Transmission Provider is the maximum value available over a given horizon.

Firm transfer capability offered by the Transmission Provider for annual and monthly horizons includes a provision of 5% of the duration to account for planned equipment maintenance and other foreseen events that may occasionally reduce the firm transfer capability offered.

Firm transfer capability offered by the Transmission Provider for weekly and daily horizons is to be available for each hour of the applicable horizon.

~~Non firm transfer capability offered by the Transmission Provider is the maximum value available over a given horizon.~~

## 1. Basic equations for calculating transfer capability

### Scheduling horizon

$$\underline{ATC}_{firm} = \underline{TTC} - \underline{ETC}_{firm} - \underline{CBM-TRM}_{firm} + \underline{PBR}$$

$$\underline{ATC}_{non-firm} = \underline{TTC} - \underline{ETC}_{firm} - \underline{ETC}_{non-firm} - \underline{CBM-TRM}_{non-firm} + \underline{CF} + \underline{PBR}$$

$$\underline{ETC}_{firm} = \underline{OQRD} + \underline{OQRND}_{firm} + \underline{NITS}_{firm} + \underline{PTP}_{firm} + \underline{ROR} + \underline{GF}_{firm} + \underline{OS}_{firm}$$

$$\underline{ETC}_{non-firm} = \underline{OQRND}_{non-firm} + \underline{NITS}_{non-firm} + \underline{PTP}_{non-firm} + \underline{GF}_{non-firm} + \underline{OS}_{non-firm}$$

### Real-time horizon

$$\underline{ATC}_{firm} = \underline{TTC} - \underline{ETC}_{firm} - \underline{CBM-TRM}_{firm} + \underline{PBR}$$

$$\underline{ATC}_{non-firm} = \underline{TTC} - \underline{ETC}_{firm} - \underline{ETC}_{non-firm} - \underline{CBM-TRM}_{non-firm} + \underline{CF} + \underline{PBNS} + \underline{PBR}$$

$$\underline{ETC}_{firm} = \underline{OQRD} + \underline{OQRND}_{firm} + \underline{NITS}_{firm} + \underline{PTP}_{firm} + \underline{GF}_{firm} + \underline{OS}_{firm}$$

$$\underline{ETC}_{non-firm} = \underline{OQRND}_{non-firm} + \underline{NITS}_{non-firm} + \underline{PTP}_{non-firm} + \underline{GF}_{non-firm} + \underline{OS}_{non-firm}$$

Where:

ATC: Available Transfer Capability

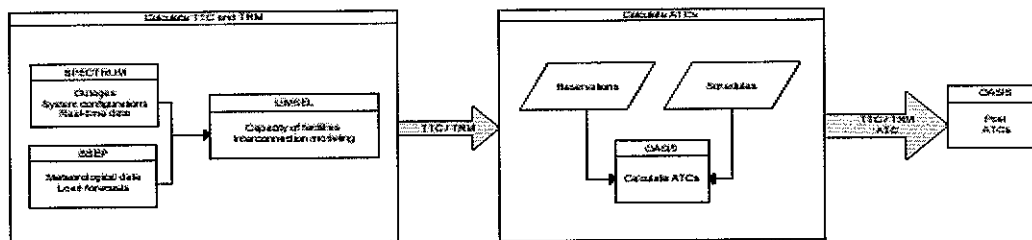
TTC: Total Transfer Capability as defined in Section 3a

ETC: Existing Transmission Commitments as defined in Section 3b

<u>CBM:</u>	<u>Capacity Benefit Margin as defined in Section 3e</u>
<u>TRM:</u>	<u>Transmission Reliability Margin as defined in Section 3d</u>
<u>CF:</u>	<u>Counterflows, scheduled flows over the related reverse path(s)</u>
<u>PBNS:</u>	<u>Postbacks - Non-Scheduled, portion of the non-scheduled ETC offered again as non-firm capacity</u>
<u>PBR:</u>	<u>Postbacks - Redirects, portion of PTP<sub>firm</sub> moved by the customer to another path and offered again on the original path</u>
<u>QCRD:</u>	<u>"Québec Ressource Désignée" [designated resource for Québec], capacity of a resource posted on OASIS and designated reserved by the Distributor as a designated resource for supplying Québec Native Load</u>
<u>QCRND<sub>firm</sub>:</u>	<u>"Québec Ressource Non Désignée" [non-designated resource for Québec], capacity of a resource posted on OASIS but not designated reserved by the Distributor as a non-designated resource for supplying Québec Native Load</u>
<u>QCRND<sub>non-firm</sub>:</u>	<u>"Québec Ressource Non Désignée" [non-designated resource for Québec], capacity of a resource posted on OASIS reserved by the Generator as a non-designated resource for supplying Québec Native Load and not designated by the Distributor</u>
<u>NITS:</u>	<u>Network Integration Transmission Service, capacity reserved for that service</u>
<u>PTP:</u>	<u>Point-to-Point, capacity reserved for confirmed Point-to-Point Transmission Services</u>
<u>ROR:</u>	<u>Roll-Over Rights, capacity reserved for renewal rights associated with Long-Term Firm Transmission Services</u>
<u>GF:</u>	<u>Grandfathered, capacity reserved under acquired rights</u>

OS: Other Services, capacity reserved under other types of Transmission Service

## 2. Steps in calculating transfer capability



## 3. Transfer capability components

### a. Total transfer capability (TTC):

- i) TTC is the amount of power that can be transmitted over an interconnection while ensuring that power system stability is maintained following a contingency and that voltage and thermal capacity limits comply with the Transmission Provider's rules and practices, and with NPCC and NERC guidelines. TTCs are estimated at the boundary of the Transmission Provider facilities.

Projected TTC values for a path are always less than or equal to that path's reference total transfer capability (TTC<sub>ref</sub>: the maximum TTC value demonstrated to be safely achievable).

- ii) To estimate TTC, the Transmission Provider uses off-line computer simulations to determine the operating limits of its Transmission System under a specific set of operating conditions. An operating limit is then established for each operating condition taken into account. Assumed operating conditions during the period under study are then compared to the limits thus determined.

TTC values for a specific period are calculated based on projected system operating conditions for that period.

TTC<sub>ref</sub> values are coordinated with the neighboring system when facilities are designed and are reassessed annually during operation.

The transfer capability of a neighboring system has an impact on the amount of power that can be transferred over interconnections. Except for interconnection facilities jointly owned by the Transmission provider and neighboring system's transmission provider, parameters outside the Transmission Provider control (facility outages, system operating conditions and limits) that affect the transfer capability of neighboring systems may be factored into the Transmission Provider TTC calculations.

iii) The Transmission Provider uses the following data to calculate TTC values:

- Forecast regional loads;
- Forecast ambient air temperatures;
- Scheduled generation from resources designated for supplying Native Load; and
- Approved outage schedules.

Forecasts of hourly Québec power needs are established for the coming ten days based on a combination of models that factor in hourly weather data. Such forecasts are updated every five minutes based on the latest discrepancies observed. They are also refreshed every 20 minutes based on any new pertinent information. The subsystem load is forecast using a linear model relating the hourly power of each subsystem to forecast hourly Québec power needs. The forecast regional subsystem load is refreshed every 20 minutes, just after forecast hourly Québec power needs are calculated.

Beyond ten days, a longer-term forecast revised two to four times a year is used. That forecast establishes hourly Québec needs and weekly demand peaks corresponding to the Distributor's monthly forecasts for the present year and for the coming year.

When outages of certain transmission facilities in the interconnection system occur, the amount of

local generation available affects TTC values. Assumptions based on mean runoff are then used since run-of-the-river hydropower is involved.

Only actual outages and transmission facility outages, planned for the long term or approved for the short term, are factored into the TTC calculation.

- iv) The following factors affect the Transmission Provider transfer capabilities.

Transfer capability of interconnection systems:

Interconnection systems are regional transmission systems operated at 120, 230 or 315 kV. These systems feed interconnections and sometimes also load-serving substations. The transfer capability of such systems can be limited by the thermal constraints of component equipment (transformers, transmission lines). Capability may also be limited by minimum-voltage constraints of component load-serving substations or by stability constraints of component generating stations.

Electrical ratings for interconnection equipment:

The Transmission Provider equipment is designed to be used in compliance with precise mechanical and electrical ratings. In particular, the thermal capacity of interconnection equipment varies with ambient air temperature. For most interconnection equipment, increased temperature results in decreased capacity.

Equipment outages for facility maintenance:

Equipment in the Transmission Provider's system must occasionally be taken out of service to ensure the maintenance of facilities. Such outages result in reduced transfer capability over interconnections.

Loads connected to interconnection systems:

Some interconnection systems supply load-serving substations. The effect of such internal loads is factored into the TTC calculation for deliveries to the neighboring system.

For some interconnections, energy is transferred by switching a load block from a neighboring system to

the Transmission Provider's system. The transfer capability then considers the maximum load, annual or seasonal, of the substations switched.

Generation connected to interconnection systems:

Some interconnections are supplied in part by local generating stations. The effect of such internal generation is factored into the TTC calculation for energy received from the neighboring system.

For some interconnections, energy is transferred by switching generating units from one system to the other. Since the transfer capability in such instances considers the rated capacity of the generating units switched over rather than the output actually available, the calculated TTC for a given period may exceed the generation that can be transferred during that period.

For interconnections where generating units must be isolated on the neighboring system, prior agreement shall be reached with the Generator operating the generating units for each reservation request for Transmission Service over such interconnections, and this at the Generator's discretion.

Single-contingency loss of load (SCLL) limit:

The tripping of an interconnection being used for deliveries is equivalent to a loss of load on the Transmission Provider's system and results in a rise in system frequency. In order to ensure integrity of the Transmission Provider's system and continuity of service, the system operator limits the amount of load (MW) that can be tripped following a single contingency. This limit, called "SCLL", depends on the spinning capacity feeding the Transmission Provider's system and on the interconnection's location. The higher the spinning capacity, the higher the SCLL limit. Generally, spinning capacity increases with deliveries, decreases with receipts and follows changes in load. The SCLL limit is thus most constrictive at low loads and maximum receipts. The TTC for deliveries that the Transmission Provider establishes for each interconnection takes the SCLL limit into account.

Single-contingency loss of generation (SCLG) limit:

The tripping of an interconnection being used to

receive power is equivalent to a loss of generation on the Transmission Provider's system and results in a drop in system frequency. In order to ensure integrity of the Transmission Provider's system, the system operator limits the amount of generation (MW) that can be tripped following a single contingency. This limit, called "SCLG", depends on the spinning capacity feeding the Transmission Provider's system. The higher the spinning capacity, the higher the SCLG limit. Generally, spinning capacity increases with deliveries, decreases with receipts and follows changes in load. The SCLG limit is thus most constrictive at low loads and maximum receipts. The TTC for receipts that the Transmission Provider establishes for each interconnection takes the SCLG limit into account.

Concurrent paths:

Certain portions of the Transmission Provider's system may supply more than one interconnection. Transfer capacity over such portions of the system may be less than the sum of the individual transfer capabilities of all interconnections supplied. ATC calculations factor in existing transmission commitments over such concurrent paths.

Simultaneous wheel-in capacity:

The total wheel-in capacity of the Québec Control Area varies as a function of system load, deliveries to neighboring systems, and the minimum generating capacity to be maintained on the system. This constraint could affect TTC values for receipts but is very rarely a limiting factor.

b. Existing transmission commitments (ETC):

- i) ETC is the total amount of power that is already reserved over a path, plus capacity required for supplying Native Load and posted on OASIS.
- ii) Since the Transmission Provider offers ~~Point to Point~~ Transmission Services over interconnections with neighboring systems, the ETC related to Native Load needs is represented directly by ~~Point to Point (PTP) Service~~ reservations designated as "QCRD and QCRDN entries".
- iii) The ETC includes reservation requests for PTP service once they reach "Confirmed" status or, for

long-term PTP service reservations, once the Service Agreement is executed.

- iv) It is assumed that the customer will exercise roll-over rights (ROR) associated with long-term PTP service reservations until such rights expire or are superseded by a competing requests under the provisions of Section 2.2 of Part I herein.
- v) On a real-time horizon, if no schedule is received in association with an existing reservation, the transfer capability available for non-firm PTP services is increased by the amount reserved but not scheduled.

c. Available flowgate capability (AFC):

AFC is used instead of ATC to estimate the transfer capability between Transmission Provider systems when transmission facilities in one of the systems involved are affected by power flows in the other systems. Given that the Transmission Provider's system is not subject to inadvertent power flows from neighboring systems since it is connected to them only by controllable interconnections, the flowgate concept does not apply to it.

d. Transmission reliability margin (TRM):

i) Definition of TRM

TRM quantifies inaccuracies associated with transfer capability forecasts. The inaccuracies are due to the variability of the following factors affecting the TTC calculation: system load, ambient air temperature, operating voltage of the interconnection system, internal generation on the interconnection system, and spinning capacity of the system as a whole. The TRM for some interconnections also includes uncertainty for unexpected transmission equipment failure, a reserve to cover system configuration changes that may be required as a result of Transmission Service requests and parameters outside the Transmission Provider control (facility outages, system operating conditions and limits) that affect the transfer capability of neighboring systems.

For interconnections where firm transfer capability is coordinated between the Transmission Provider's system and a neighbouring system, the definition of TRM corresponds to the higher of the following two values: (1) the TRM of the neighbouring system, and (2) the TRM of the Transmission Provider.

ii) TRM calculation method

TRM values are generally based on historical forecasting errors. On interconnections where Transmission Service requests may entail system configuration changes, TRMs are fixed values set on the basis of the configurations possible.

For interconnections where firm transfer capability is coordinated between the Transmission Provider's system and a neighbouring system, the calculation of TRM for these interconnections corresponds to the difference between the total transfer capability (TTC) of the Transmission Provider and the firm transfer capability before the ETCs on the neighbouring systems are taken into account.

iii) Databases for TRM calculations

The databases used for TTC calculations are also used to calculate TRM values.

iv) Application of TRM

TRM values are only used in calculating firm available transfer capability. A nil TRM is generally used in calculating non-firm available transfer capability.

e. Capacity benefit margin - CBM

CBM is a firm transfer capability reserved for importing power in an emergency situation. The Transmission Provider does not presently use CBMs in calculating ATCs.