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Transmission Rate Design for Hydro-Québec

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Direct Testimony of:

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Table of Contents

1. Introduction..... 1

2. Purpose and Organization of Testimony 2

3. Objectives of Transmission Tariff Design..... 3

4. Overview of HQ Transmission Tariff 10

5. Transmission Tariff Evaluation..... 15

 Goals of Transmission Rate Design 15

 Consistent with Industry Standard 17

 Appropriate to Market Conditions 18

6. Conclusion..... 20

List of Figures

Figure 1: Design Selection Process..... 8

1 **1. Introduction**

2 **Q1. Please state your name, affiliation and business address.**

3 A1. My name is Ren Orans. I am President of Energy and Environmental Economics
4 Inc. (E3) located at 353 Sacramento Street, Suite 1700, San Francisco, California,
5 94111, USA.

6

7 **Q2. Please state your qualifications and experience.**

8 A2. With nearly 20 years of experience in the electric utility business, I have worked
9 extensively in wholesale and retail ratemaking, integrated resource planning, and
10 transmission and distribution (T&D) planning. I have testified before state and
11 provincial regulators on transmission pricing, retail and wholesale rate design,
12 market restructuring, and stranded asset valuation. Over the last 5 years, my work
13 has focused on transmission and distribution pricing and planning for electric
14 utilities in North America. I received my Ph.D. in Civil Engineering from
15 Stanford University and my B.A. in Economics from U.C. Berkeley. The
16 attached C.V. further describes my qualifications and experience.

17

18 **Q3. Have you testified in Québec and other Canadian provinces?**

19 A3. I have not testified in Québec. However, I have testified before the British
20 Columbia Utilities Commission on related topics, including their 1995 Electricity
21 Market Structure Review and B.C. Hydro's 1996 and 1997 Wholesale
22 Transmission Service applications. B.C. Hydro's 1997 proceeding addressed
23 issues that were very similar to the issues in this case. Earlier this year, I testified

1 before the Ontario Energy Board (OEB) on behalf of Ontario Power Generation
2 (OPG), addressing Ontario Hydro Network Services' 2000 transmission rate
3 application.
4

5 **2. Purpose and Organization of Testimony**

6 **Q4. What is the purpose of your testimony?**

7 A4. The purpose of my testimony is to evaluate Hydro-Québec's transmission tariff in
8 the context of the market structure in place today in Québec and relative to the
9 generally accepted goals for transmission tariff design in North America.
10

11 **Q5. How is your testimony organized?**

12 A5. My testimony is organized into three major sections. First, I will summarize the
13 objectives of transmission tariff design. Second, I will describe Hydro-Québec's
14 transmission tariff proposal and show that it is consistent with both the industry
15 standard tariff used in North America for areas without competitive energy pools
16 and the U.S. Federal Energy Regulatory Commission's *Pro Forma* transmission
17 tariff.¹ Finally, I will demonstrate that the Hydro-Québec proposal meets the
18 major objectives for transmission tariff design, and conclude that it is the most
19 appropriate tariff form for the type of electricity markets that exist in Québec
20 today.

¹ The majority of jurisdictions that do not have an energy pool rely on a version of FERC's Pro Forma tariff to provide comparable access to transmission services. The jurisdictions with energy pools are PJM, New England, New York, California, Alberta, and soon, Ontario.

1 **3. Objectives of Transmission Tariff Design**

2 **Q6. What are the major objectives for Transmission Tariff Design?**

3 A6. Transmission tariff design should:

4 A) meet the goals of transmission rate design,

5 1) to collect the transmission revenue requirement;

6 2) to be simple to implement and use;

7 3) to offer open and comparable access;

8 4) to be equitable, and

9 5) to promote efficiency;

10 B) be consistent with the industry standard; and

11 C) be appropriate for the market environment in which it is applied.

12

13 **Q7. What is the industry standard for transmission tariff design?**

14 A7. In North America today, the industry standard tariff is the FERC *Pro Forma*
15 tariff.

16

17 **Q8. Please describe the objectives and main characteristics of the FERC *Pro***

18 ***Forma* tariff.**

19 A8. The *Pro Forma* tariff standardizes what FERC considers to be comparable terms
20 and conditions that provide for non-discriminatory open access to transmission
21 systems. The purpose of the tariff is to allow all transmission users, be they utility
22 owned generators or other parties, to have transmission access to wholesale power
23 markets under the same transmission rates, terms and conditions. The FERC

1 tariff specifies two types of transmission service, Network Integration and Point-
2 to-Point, and both services use non-geographically differentiated (postage stamp)
3 tariffs. FERC does not require native load to be served under the *Pro Forma*
4 tariff. The Network Integration service is typically used to serve domestic loads,
5 while Point-to-Point service is typically used for imports, exports and other third
6 party wheeling transactions. Under the FERC tariff, if there is a shortage of
7 available transmission capacity, transactions are prioritized according to the so-
8 called bumping rules. Firm transactions and those with longer durations are given
9 priority.

10
11 **Q9. What jurisdiction does FERC have over the transmission pricing form used**
12 **by Hydro-Québec?**

13 A9. Although FERC has no direct jurisdiction over Hydro-Québec, FERC indirectly
14 influences Hydro-Québec's choice of tariff design through its licensing process of
15 those wishing to sell electric power at market based prices in the U.S. As part of
16 its open access policy, FERC instituted a reciprocity requirement on all non-
17 jurisdictional utilities that use open access transmission tariffs. The reciprocity
18 clause requires that in order for a supplier to receive comparable transmission
19 access to U.S. markets, that supplier's transmission affiliate must provide
20 comparable access to its own market. The reciprocity clause has had the impact
21 of requiring foreign utilities in both Canada and Mexico to develop and
22 implement *Pro Forma* tariffs in order to sell into U.S. wholesale markets at
23 market-based prices. FERC does not have any jurisdiction over or intent to

1 influence the rate levels of non-jurisdictional utilities, but is only concerned that
2 the form of the rate and the terms and conditions of access are comparable.

3

4 **Q10. Why does a market environment drive the choice of a transmission tariff?**

5 A10. As background, it is important to realize that transmission pricing serves two
6 purposes. First, it should collect the transmission revenue requirement of the
7 transmission owning utilities. Postage stamp tariffs are the industry standard
8 method for collecting the transmission revenue requirement. And second, it
9 should also promote efficient use of transmission and generation assets. Location
10 and time-specific congestion pricing by the grid operator or ISO, such as in PJM
11 and New York, is an example of how pricing can be used to promote efficient use
12 of transmission and generation assets.

13

14 The ability of a transmission tariff design to promote efficient use of assets is
15 dependent upon the characteristics of the wholesale market environment. The
16 market environments that exist today in North America can be divided into two
17 general types: *centralized* and *decentralized*.

18

19 In *centralized* markets, such as those in British Columbia and Québec, there is
20 one primary user of the transmission network, the integrated utility that controls
21 and operates the network and dispatches most or all of the generation resources in
22 its service territory. This type of market environment is common in jurisdictions

1 without retail access.² In this centralized environment, the primary role of the
2 transmission tariff is to provide comparable, open transmission access to non-
3 utility generators under the same terms, conditions and rates that the utility offers
4 to its own generators. The utility continues to be responsible for efficiently
5 dispatching its generation resources and maintaining system reliability based on
6 its full knowledge of its system demand, generation costs and available capacity.
7 As a result, the utility does not need a sophisticated transmission tariff design to
8 coordinate and schedule transactions between many decentralized energy buyers
9 and sellers to assure efficient and reliable operation of the bulk power system. A
10 simple, embedded cost-based postage stamp tariff can be used to implement
11 comparable open access.

12
13 In contrast, in a *decentralized* markets like those in California, PJM, New York,
14 New England and Alberta, there are many separate users of the transmission
15 network. Unlike the case of the centralized environment, where the integrated
16 utility directly controls the normal operation of the bulk power grid, system
17 operation is based on scheduled transactions that result from energy bidding and
18 trading among numerous transmission users. The design of a transmission tariff
19 in this decentralized decision-making model now takes on an important new
20 function: to induce grid users to schedule transactions that promote efficient

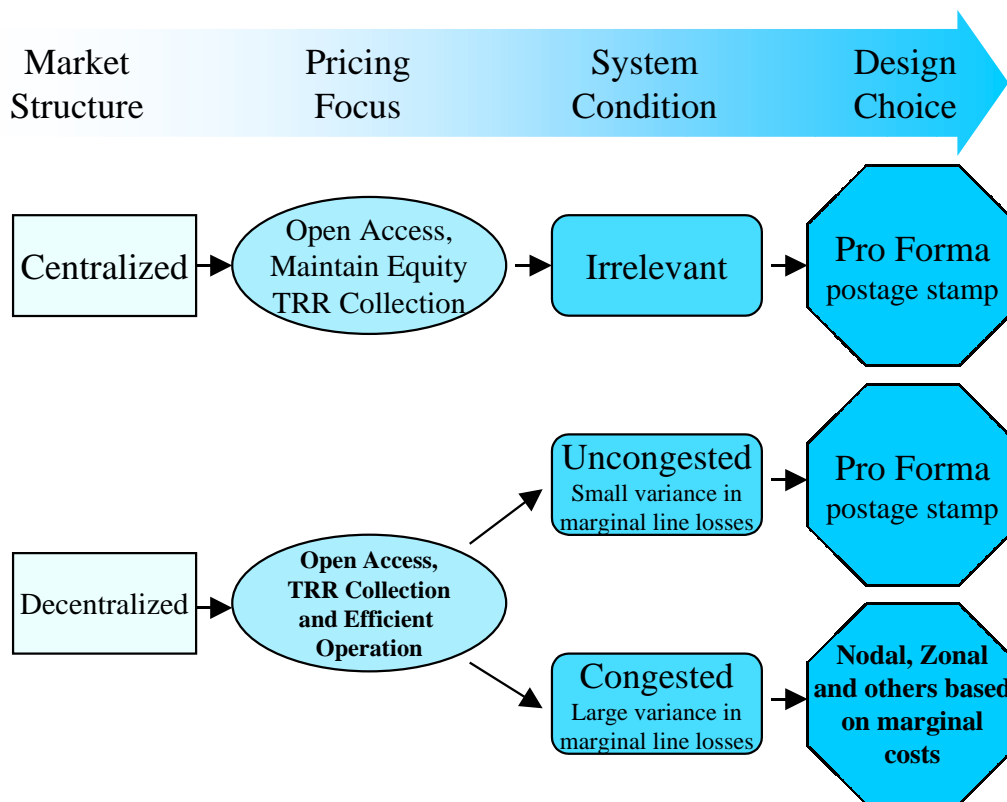
² In jurisdictions with retail access, retail customers can purchase electricity from individual suppliers in competitive generation markets and are not required to purchase generation from the incumbent utility.

1 dispatch of generators, while maintaining system reliability. To accomplish this,
2 the transmission tariff needs to reflect the variable costs of transmission use. The
3 variable costs include the out-of-pocket costs (i.e., losses and scheduling)
4 associated with each transaction, as well as a premium (congestion) sufficient to
5 clear the transmission market when transmission capacity would otherwise be
6 inadequate to meet demand. Congestion costs reflect the full premium, exclusive
7 of losses and administration, that the market is willing to pay for using a
8 congested transmission path. Thus, the efficient price for transmitting power
9 from one location to another location in these decentralized markets should reflect
10 the differences in the locational out-of-pocket costs and the costs of congestion.

11

12 The diagram depicted in Figure 1 illustrates a process for identifying tariff designs
13 that are appropriate for the two types of market environments.

1 **Figure 1: Design Selection Process**



2

3

4 In a *centralized* market, the primary goals of a tariff design are to promote open
 5 and comparable access to transmission services, to avoiding shifting embedded
 6 costs among existing bundled service transmission users, and to collect the
 7 transmission owner’s revenue requirement. Congestion is relieved in this system
 8 through economic redispatch by the integrated utility. Because efficient dispatch
 9 and reliable operation are already achieved by the integrated utility, a simple
 10 postage stamp design is the most appropriate choice.³

³ Transmission owners that offer comparable wholesale transmission services in a centralized market structure tend to focus on minimizing bill impacts to existing customers.

1 In a *decentralized* environment, the transmission tariff takes on the additional role
2 of providing price signals to achieve efficient dispatch and operation of the bulk
3 power system. This is particularly important in areas like New York and PJM
4 where there is a shortage of transmission capacity, a significant amount of loop
5 flow, and many thermal generators with different operational costs. In these
6 markets, efficient dispatch through locational pricing of transmission service
7 assures that the lowest cost generators are dispatched and are given access to the
8 transmission system. In these systems with significant congestion, nodal pricing,
9 zonal pricing and other marginal-cost based tariff designs are appropriate. In
10 contrast, in large hydro-based systems with extensive high voltage transmission
11 systems, where there is generally very small amounts of congestion and losses are
12 not material to dispatch order, such price signals are immaterial and a simple
13 postage stamp tariff is a suitable design.

14

15 **Q11. How are the fixed costs of the existing transmission system recovered in**
16 **decentralized systems?**

17 A11. Even in decentralized systems that require locational congestion pricing to
18 encourage efficient operations, the transmission revenue requirement is collected
19 on a postage stamp basis within each transmission owner's service territory. For
20 example, in PJM, New York and California, which all have location specific
21 congestion pricing, each transmission owner collects the majority of its fixed
22 costs from postage stamp access fees paid by loads connected to its system. To
23 avoid cost shifting between different transmission owning utilities within the

1 same market, each transmission owner has a different access fee. The postage
2 stamp tariff collects the fixed or embedded costs of the transmission system.
3 Locational pricing only collects the variable costs of transmission.
4

5 **4. Overview of HQ Transmission Tariff**

6 **Q12. Please describe the transmission rate design that Hydro-Québec uses today.**

7 A12. Hydro-Québec has an Open Access *Pro Forma* Transmission Tariff that follows
8 the tariff form, terms and conditions prescribed by FERC in Order 888, issued in
9 April 1996. The tariff offers two transmission services, Network Integration and
10 Point-to-Point Transmission Service. The terms and conditions of both services
11 are designed to provide comparable transmission access to all eligible wholesale
12 customers. Hydro-Québec proposes that native load customers, customers not
13 eligible to take either Network Integration or Point-to-Point Service, receive
14 transmission service at the same rate as Network Integration Service.
15

16 The Network Integration Service rate is available for firm service with contract
17 durations equal to or greater than one year. It is designed for customers with
18 multiple points of delivery (POD) or points of receipt (POR). Network
19 Integration Service is billed to customers on the basis of the maximum of the
20 projected sum of their demands at either the customer's points of delivery or
21 points of receipt. This feature allows Network Integration Service customers with
22 multiple sources of generation to efficiently utilize their resources to serve
23 network loads in Hydro-Québec's control area.

1 In contrast to Network Integration Service, Point-to-Point Service applies to
2 transactions with a specified Point-of-Delivery (POD) and Point-of-Receipt
3 (POR). It requires reservation by its users for a specific period of time (day,
4 week, month, or year). The reservation fee is a take-or-pay payment equal to the
5 capacity reserved times the applicable rate. The applicable rates in the tariff are
6 postage stamp rates based on the transmission provider's system-wide average
7 embedded costs. The standard Point-to-Point rate offered by Hydro-Québec can
8 be discounted to improve the grid's capacity utilization. If a rate discount is
9 given, however, the same discount must be offered to all eligible users as long as
10 they have the same POD and capacity is available.

11

12 Point-to-Point service can be long-term (1 year or more) or short-term (under 1
13 year). Long-term service is always firm. Short-term service can be firm or non-
14 firm. Non-firm service is curtailed before firm service in the event of a shortage
15 of available transmission capacity.

16

17 To provide usage flexibility, the tariff allows a user of firm Point-to-Point service
18 to request Hydro-Québec to alter the POR and POD. But the resulting service
19 will only be provided on a non-firm basis and will not displace services already
20 scheduled.

21

1 **Q13. Do retail customers in Québec have access to these two services?**

2 A13. No. Only wholesale customers (those who buy power for resale) are eligible to
3 use Hydro-Québec's transmission tariff.

4

5 **Q14. What service will be used by Hydro-Québec's retail affiliate to purchase**
6 **transmission services for native load?**

7 A14. Hydro-Québec proposes to provide transmission service for native load at rates
8 equal to the Network Integration Service rate, consistent with FERC Order 888.

9

10 **Q15. How does Hydro-Québec compute the rates for the Network Integration and**
11 **Point-to-Point services?**

12 A15. Rates for Point-to-Point and Network Integration service are calculated to ensure
13 that the embedded costs of the existing interconnected transmission system are
14 collected on the basis of a customer's load ratio share of the system peak. Rates
15 are calculated on the basis of demand (MW), rather than energy (MWh). For
16 annual services (Network Integration and Point-to-Point reservations of one year
17 or longer), the rate is calculated to reflect the customer's share of Hydro-Québec's
18 annual peak. For shorter term Point-to-Point services, the rates are calculated to
19 reflect the customer's contribution to each of the monthly peaks. The steps below
20 describe how the rates are calculated.

- 21 1. Develop the Transmission Revenue Requirement (TRR).
- 22 2. Estimate short term sales revenues, and subtract from TRR.

23

24

- 1 3. Develop Point-to-Point Rates.
- 2 ▪ The annual Point-to-Point rate is equal to the total TRR (less short-
- 3 term sales revenues) divided by the annual peak demand. Annual peak
- 4 demand is estimated as the sum of the Hydro-Québec estimated
- 5 internal market peak demand and estimated Point-to-Point
- 6 reservations.
- 7 ▪ The monthly Point-to-Point rate is equal to the total TRR (less short-
- 8 term sales revenues) divided by the sum of the twelve monthly
- 9 maximum peak demands. Daily rates are equal to the monthly rate
- 10 divided by 20 days. Weekly rates are equal to the daily rates
- 11 multiplied by 5. Hourly rates are equal to the daily rate divided by 24.
- 12 ▪ The postage stamp rate is applied to the customer's transmission
- 13 capacity reservation for the specified time period.
- 14 4. Calculate the Network Integration Rate. The rate for Network Integration
- 15 Service is calculated for each user based on the user's load-ratio share of
- 16 the sum of the estimated annual peak of Network Integration Service and
- 17 native load customers. The revenue or rate paid by each user is equal to
- 18 their load-ratio share multiplied by the TRR (less Point-to-Point revenues).
- 19 For example, if total annual peak was 100 MW, and one user had 25 MW
- 20 of that total, then that user's share of revenues would be equal to one-
- 21 fourth (25/100) of the TRR (less Point-to-Point revenues).
- 22 5. Calculate the Rate for Native Load. Native load will pay the same rate as
- 23 Network Integration Service customers.
- 24

25 **Q16. Is the computation consistent with FERC Order 888 and standard**

26 **ratemaking practice?**

27 A16. Yes, it is, with the exception that FERC generally recommends that transmission

28 owners base their rates on the sum of the monthly coincident peaks (12-CP basis),

29 rather than on a single annual peak (1-CP). Hydro-Québec has chosen to use both

1 the 12-CP and 1-CP methods in its rate design. It uses a 12-CP basis for
2 calculating monthly, weekly, daily and hourly rates for Point-to-Point service, but
3 uses a 1-CP basis for calculating the annual services (Network Integration and
4 long term Point-to-Point). In general, the 12-CP method is best suited for
5 transmission systems that are planned to meet each of the twelve monthly peak
6 demands. However, Hydro-Québec plans its system for its single winter peak.
7 Hence, for annual service (Network Integration and long term Point-to-Point), the
8 costs of service are more closely reflected in rates if the 1-CP method is used. For
9 utilities that plan their systems to meet their annual peak, FERC has
10 acknowledged that the 12-CP method is not as appropriate as the use of 1-CP and
11 has stated a willingness to accept alternative allocation proposals.

12
13 In contrast, Hydro-Québec has proposed that customers relying on shorter-term
14 services, defined as reservations equal to or less than one month, pay for their fair
15 share of the fixed costs of the system based on a 12-CP method. This more
16 closely reflects the strong seasonal nature of electricity demand in Québec. In
17 other words, the billing determinants now have the potential to more accurately
18 track differences in the month to month use of short-term services.

19
20 Other than this minor difference, the computation of rates mirrors the standard
21 industry practice.

22

1 **5. Transmission Tariff Evaluation**

2 **Q17. How did you evaluate Hydro-Québec's transmission tariff proposal?**

3 A17. I evaluated the tariff relative to each of the overall objectives for transmission
4 tariff design: A) does the tariff meet the goals of transmission rate design, B) is
5 the tariff consistent with the industry standard, and C) is the tariff appropriate for
6 the market environment in which it is applied.

7 Goals of Transmission Rate Design

8 **Q18. Does the Hydro-Québec proposal meet the first four goals of transmission**
9 **rate design: 1) to collect the transmission revenue requirement, 2) to be**
10 **simple to implement and use, 3) to offer open and comparable access, and 4)**
11 **to be equitable?**

12 A18. Yes, it does. First, Hydro-Québec's proposed tariff prices the Network
13 Integration, native load, and point-to-point services based on average embedded
14 costs, thus ensuring the full collection of the estimated transmission revenue
15 requirement. Second, the tariff has a postage stamp design with well-understood
16 terms and conditions that Hydro-Québec has already implemented. Being the
17 industry standard, it is easy to use by all eligible customers. Third, the tariff
18 adheres to FERC's Order 888 *Pro Forma* tariff and therefore offers open and
19 comparable access to all eligible users. Finally, the tariff is equitable because it
20 minimizes the rates of native load customers, for whom the system was primarily
21 built to serve.

22

1 **Q19. How does the tariff meet the last goal of promoting economic efficiency?**

2 A19. The tariff promotes economic efficiency under Québec’s market environment and
3 system condition by encouraging efficient use of the transmission system.

4 Because the grid is primarily used by an integrated utility, Hydro-Québec can
5 operate the grid efficiently and reliably, without relying on a more complicated
6 tariff that prices congestion by location. To improve capacity utilization, the tariff
7 permits discounting to promote efficient use the capacity of the system.

8 Moreover, the discounting can be differentiated by location. In the unlikely event
9 of a transmission constraint that is not resolved through centralized generation
10 redispatch, the tariff resolves congestion based on reliability differentiation of
11 transmission service (the FERC *Pro Forma* “bumping rules” previously
12 discussed).

13
14 Hydro-Québec’s rate discounting also has the potential to promote economically
15 efficient levels of trade. With rates based on the full average embedded costs, the
16 *Pro Forma* tariff can at times prevent economically efficient transactions. FERC
17 recognized this fact in its Order 888A by explicitly allowing transmission owners
18 to voluntarily offer discounts for the purpose of increasing throughput on the
19 transmission system. This discounting policy is important to Hydro-Québec
20 because there are times when the full average embedded cost-based transmission
21 rate could be so high as to stifle trade. To assure comparability, FERC requires
22 that any discounts that are offered must be posted on the electronic bulletin board

1 (i.e., the Open Access Same Time Information System or OASIS), and the same
2 discount must be offered on all unconstrained paths that have the same POD.

3

4 **Q20. Does this practice of discounting short-term point to point service create cost**
5 **shifting to native load and customers of Network Integration Service?**

6 A20. No, discounting actually provides a method for Hydro-Québec to increase the
7 revenues it receives for additional transactions on its system, including exports,
8 thereby reducing the charges paid by native load, long-term Point-to-Point
9 customers, and Network Integration Service customers. Increasing the volume
10 of transactions allows Hydro-Québec to generate revenues that reduce the portion
11 of embedded costs that must be collected from native load and customers of the
12 Network Integration and long term Point-to-Point Services.

13

14 Consistent with Industry Standard

15 **Q21. Is the Hydro-Québec proposal consistent with the industry standard?**

16 A21. Yes. As I explained earlier in my testimony, Hydro-Québec's proposal is
17 consistent with the FERC *Pro Forma* tariff, which is the standard tariff form used
18 by the vast majority of all North American transmission owners.

19

20 **Q22. What jurisdictions are most comparable to Québec?**

21 A22. Québec is a centralized, hydro-based generation system that uses a bilateral
22 trading model. Similar jurisdictions include British Columbia and the U.S.
23 Pacific Northwest.

1 **Q23. What forms of transmission tariffs are used in these comparable**
2 **jurisdictions?**

3 A23. The *Pro Forma* tariff is used in British Columbia and throughout the U.S. Pacific
4 Northwest, where bilateral trading is the foundation of the wholesale electricity
5 market.

6

7 **Q24. Do all Canadian provinces follow the standard tariff form used in British**
8 **Columbia and Québec?**

9 A24. No. The transmission tariffs in both Alberta and Ontario differ substantially from
10 the *Pro Forma* tariff used in British Columbia and in Québec. Alberta and
11 Ontario have adopted pool market structures. Access to transmission is granted
12 to generators who are dispatched by the pool based on who has the lowest bids to
13 supply energy. However, even though these jurisdictions do not offer the same
14 types of transmission services as the *Pro Forma* tariff, the majority of the
15 embedded costs of the transmission system are still collected on a postage stamp
16 basis.

17

18 Appropriate to Market Conditions

19 **Q25. Is Hydro-Québec's proposed tariff appropriate for the market environment**
20 **in Québec?**

21 A25. Yes, it is. Québec has a centralized market environment in which efficient
22 dispatch and reliable operation are achieved by the integrated utility. Under these

1 conditions, a postage stamp design based on average embedded costs as proposed
2 by Hydro-Québec is the most appropriate choice.

3 **Q26. Do you believe the conditions you described in the jurisdictions with**
4 ***decentralized* markets exist in Québec?**

5 A26. No, Québec has neither retail access, nor a wholesale power pool, and continues
6 to have *centralized* decision making for generation dispatch. The FERC *Pro*
7 *Forma* was designed to promote wholesale bilateral trading through functional
8 separation of regulated and unregulated services, as has happened in Québec.

9
10 **Q27. How does Hydro-Québec's proposed tariff resolve congestion?**

11 A27. The tariff differentiates its services by priority consistent with the FERC *Pro*
12 *Forma* tariff. Should congestion occur, Point-to-Point service using secondary
13 PODs or PORs will be curtailed first. This is followed by short-term non-firm
14 service. Firm services are curtailed last. However, I understand from my
15 communications with Hydro-Québec that there have been no significant levels of
16 congestion in Hydro-Québec's transmission system.

17
18 **Q28. If the Régie adopts the postage stamp tariff, are they forsaking any potential**
19 **efficiency gains provided by more complicated designs?**

20 A28. No, they are not. The postage stamp design, with discounting of short-term
21 transmission and the flexibility to reassign points of delivery and receipt, does
22 have the ability to efficiently use the capacity of the system. Further, congestion,
23 though rare for Hydro-Québec's grid, can be efficiently resolved by the

1 centralized dispatch of the primary user, Hydro-Québec, using extensive
2 operating and cost information.

3

4 **Q29. How would your conclusion change if the market environment in Québec**
5 **were *decentralized*?**

6 A29. The response to this question depends on what I have called the system condition.
7 Based on my knowledge of the Hydro-Québec system, I would expect that the
8 efficiency gains from instituting locational pricing for congestion and losses
9 would be relatively small compared to the implementation costs, even in a
10 *decentralized* decision-making market.

11

12 **6. Conclusion**

13 **Q30. Based on your testimony, what is your overall recommendation?**

14 A30. The Régie should adopt Hydro-Québec's proposed transmission tariff. The
15 proposed tariff is consistent with the industry standard and provides an efficient,
16 comparable, equitable and simple method to collect Hydro-Québec's transmission
17 revenue requirement. This tariff form is also appropriate for the type of electric
18 market environment present in Québec today. It collects embedded costs for all
19 customers based on their load ratio share of the average costs of the entire system.
20 More complex forms of congestion pricing, such as nodal or zonal pricing, would
21 offer little or no additional benefits to Québec's electricity markets and would be
22 much more costly and complex to implement.

23

1 **Q31. Does this conclude your prepared testimony?**

2 A31. Yes, it does.

1 Attachment: Dr. Ren Orans CV

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San Francisco, CA 94111

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Ren Orans

Professional Experience

ENERGY AND ENVIRONMENTAL ECONOMICS, INC. (E3)
President

SAN FRANCISCO, CA
1993 - Present

Dr. Orans founded this consulting firm in 1993. The firm has three main practice areas: Litigation support, Utility planning and Business restructuring. The firm has nationally recognized experts in the fields of transmission and distribution planning, economic and regulatory theory and finance. Dr. Orans heads the Litigation support and utility planning practices for E3.

Dr. Orans' work in utility planning is centered on the design and use of area and time-specific costs for electric utilities. The first successful application was conducted for Pacific Gas and Electric Company in their 1993 General Rate Case. Using costs developed by Dr. Orans, PG&E became the first electric utility to use area and time specific costing in its ratemaking process. This seminal work led to detailed area costing applications in pricing, marketing and planning for Wisconsin Electric Company, Niagara Mohawk Power Company, Public Service of Indiana, Kansas City Power and Light, Central and Southwest Utilities, Central Power and Light, Philadelphia Electric Company, Tennessee Valley Authority and Ontario Hydro.

Dr. Orans expertise in utility planning is complimented by his practical working experience at Pacific Gas and Electric Company, where he was responsible for designing and testifying in support of their electric utility rates between 1981 to 1985. He has relied on this background along with his published papers to provide recent expert testimony on transmission pricing on behalf of BC Hydro (1996 and 1997) and Ontario Power Generation (2000). Dr. Orans has also recently testified in stranded asset cases before the British Columbia Utilities Commission and the Texas PUC on behalf of BC Hydro and Central Power and Light, respectively.

**DEPARTMENT OF ENERGY, NATIONAL ENERGY RENEWABLE LABORATORY, ELECTRIC POWER
RESEARCH INSTITUTE**

WASHINGTON, DC

Lead Consultant

1992 – 1993

Developed new models to evaluate small-scale generation and DSM placed optimally in utility transmission and distribution systems.

PACIFIC GAS AND ELECTRIC CO. - RESEARCH AND DEVELOPMENT DEPT.

SAN FRANCISCO, CA

1989 – 1991

Developed an economic evaluation method for distributed generation alternatives. The new approach shows that targeted, circuit-specific, localized generation packages or targeted DSM can be less costly than larger central generation alternatives. Developed the evaluation methodology that led to PG&E's installation of a 500KW PV facility at their Kerman substation. This is the only PV ever designed to defer the need for distribution capacity.

ELECTRIC POWER RESEARCH INSTITUTE

PALO ALTO, CA

1988 – 1992

Developed the first formal economic model capable of integrating DSM into a transmission and distribution plan; the case study plan was used by PG&E for a \$16 million pilot project that was featured on national television.

DEPARTMENT OF ENERGY**WASHINGTON, DC****1989–1990**

Lead consultant on a cooperative research and development project with the People's Republic of China. The final product was a book on lessons learned from electric utility costing and planning in the United States.

PACIFIC GAS AND ELECTRIC COMPANY -CORPORATE PLANNING DEPT.**SAN FRANCISCO, CA****1987–1992**

Lead consultant on a joint EPRI and PG&E research project to develop geographic differences in PG&E's cost-of-service for use in the evaluation of capital projects. Developed shared savings DSM incentive mechanisms for the California Collaborative.

PACIFIC GAS AND ELECTRIC COMPANY**SAN FRANCISCO, CA****Rate Department Economist****1981–1985**

Responsible for the technical quality of the testimony for all electric rate design filings. Developed the policy and rates for collecting more than \$5.5 billion per year from nearly 3.5 million customers. Also responsible for research on customers' behavioral response to conservation and load management programs. The research led to the design and implementation of the largest residential time-of-use program in California and a variety of DSM programs.

*Education***STANFORD UNIVERSITY****PALO ALTO, CA****Ph.D. in Civil Engineering , Specialization in utility costing and pricing.****1989****MS in Engineering, Specialization in water and energy.****1987****UNIVERSITY OF CALIFORNIA AT BERKELEY****BERKELEY, CA****BA in Economics, Concentration in applied microeconomics.****1981**

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