2008 Long Term Acquisition Plan

BC hydro

APPENDIX E

Direct Testimony of Dr. Ren Orans

1. Introduction and overview

Q1. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS AFFILIATION.

A1. My name is Ren Orans. I am the Managing Partner of Energy and Environmental Economics, Inc. (E3), located at 101 Montgomery Street, Suite 1600, San Francisco, California 94104, USA.

Q2. PLEASE STATE YOUR QUALIFICATIONS AND EXPERIENCE.

A2. With over 25 years of experience in the electric utility business, I have worked extensively in transmission planning and pricing, integrated resource planning, and wholesale and retail ratemaking. Prior to forming E3, I worked at Pacific Gas and Electric Company, where I was responsible for electric rate design.

I received my Ph.D. in Civil Engineering from Stanford University and my B.A. in Economics from U.C. Berkeley. My resume, included as Attachment 1 to this appendix, further describes my qualifications, experience and publications.

Q3. HAVE YOU PREVIOUSLY TESTIFIED ON MATTERS RELATED TO PRICE ELASTICITY IN THE ELECTRICITY SECTOR?

A3. Yes. In connection to my work in electricity planning and rate design, I have testified on electricity demand forecasts that incorporate estimates of customer price response.

Q4. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE BRITISH COLUMBIA UTILITIES COMMISSION (BCUC)?

A4. Yes. I have testified on behalf of BC Hydro before the BCUC in the following cases: Electricity Market Structure Review (1995); Wholesale Transmission Services Application (1995); Wholesale Transmission Services Application (1997); and Residential Inclining Block Rate Application (2008). I have also testified on behalf of British Columbia Transmission Corporation on its Open Access Transmission Tariff Application (2005).

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A5. The purpose is to describe my recommendations to BC Hydro regarding appropriate price elasticity estimates and their use in estimating rate-induced conservation impacts.

Q6. PLEASE DESCRIBE YOUR RECOMMENDATIONS.

A6. My recommendations are as follows. First, BC Hydro should use a single short-run price elasticity to project rate-induced conservation, with separate accounting of the longer term impacts of changes in government codes and standards and BC Hydro Power Smart programs. Adopting my recommendation has simplified BC Hydro's previous process that used short- and long-term price elasticities and will avoid double counting of rate-induced and codes and standards/program-induced conservation.

Second, BC Hydro should adopt a conservative price elasticity estimate of -0.1 to estimate the aggregate impact of an average rate increase and a rate design change from a flat rate to an inclining block tariff for residential and commercial customers.

Finally, it is reasonable for BC Hydro to use -0.05 as the price elasticity estimate for decomposing the total rate-induced conservation impact into rate level-induced and rate design-induced conservation, as is done in BC Hydro's 2007 Electric Load Forecast.

Q7. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A7. Section 2 discusses the estimation methods used by BC Hydro to quantify rate-induced conservation and the reasons supporting the use of a single short-run price elasticity estimate. Section 3 describes my development of the -0.1 elasticity value for use by BC Hydro. Section 4 concludes.

2. Estimating rate-induced conservation

Q8. PLEASE DESCRIBE HOW TO ESTIMATE RATE-INDUCED CONSERVATION FOR A GIVEN RATE CLASS.

A8. Given the data on the class' sales before a rate increase and an estimate of price elasticity, the conservation effect due to a rate increase can be estimated using equation (1) below:

Conservation effect = (Percent rate increase * Elasticity) * Class sales. (1)

This equation reflects the fact that price elasticity measures the price responsiveness of consumption, expressed as the percentage change in quantity per a 1-percent change in price. For example, an elasticity of -0.10 means that a 1-percent increase in real price would lead to a 0.1 percent decrease in consumption. Hence, the term (Percent rate change * Elasticity) in equation (1) is the percentage change in sales, which when multiplied by the class sales, yields an estimate of rate-induced conservation.

Q9. WHAT WERE THE ELASTICITY ASSUMPTIONS USED IN BC HYDRO'S 2006 ELECTRIC LOAD FORECAST?

A9. BC Hydro's 2006 Electric Load Forecast used both short- and long-run elasticities by sector. Table 1 below shows the elasticity values used by BC Hydro to prepare its 2006/07 to 2026/27 forecast. This forecast is net of separate conservation estimates due to changes in codes and standards and new Power Smart Programs.

Table 1: Mean price elasticity values used by BC Hydro for its 2006/07 to 2026/27 forecast

Sector	Short-term elasticity	Long-term elasticity
Residential	-0.2	-0.27
Commercial	-0.1	-0.35
Industrial	-0.2	-0.28

Source: "Electric Load Forecast 2006/07 to 2026/27", Market Forecasting, Energy Planning, Customer Care and Conservation, p.88.

Q10. DO YOU HAVE ANY CONCERNS REGARDING THE ESTIMATION APPROACH AND ELASTICITY ASSUMPTIONS USED IN BC HYDRO'S 2006 ANNUAL FORECAST?

A10. Yes. My concerns are as follows. First, double counting of energy savings may occur due to the combined use of a long-run elasticity estimate and conservation induced by government codes and standards and Power Smart programs. A long-term price elasticity estimate includes consumption changes due to customers changing their electricity consuming equipment, which are also influenced by changes in codes and standards and Power Smart programs. As long as BC Hydro's electricity rates were not increasing, the potential for, or magnitude of, double counting was relatively small. However, now as BC Hydro is faced with the potential need to increase both its rates and its expenditures on Power Smart programs, the possibility of double counting is substantially larger.

Second, for low electricity cost jurisdictions such as British Columbia, relatively small rate changes should have little impact on customers' equipment purchase behaviour (e.g., equipment replacement or turnover). Thus, it is reasonable to assume that the long-term impact due to energy efficiency improvements in equipment would mainly result from government codes and standards and Power Smart programs.

Finally, the long-run elasticity estimates used by BC Hydro in its 2006 demand forecast are on the higher end of the range of those found for other winter-peaking jurisdictions with low and stable rates (please see Section 3 below for more details).

These concerns have led me to recommend that BC Hydro eliminate the distinction between short- and long-run price elasticity and use a single estimate that reflects a plausible but relatively modest consumer price response. This elasticity value does not account for any sales reductions due to Power Smart programs and improvements in government codes and standards, which continue to be accounted for separately. I understand that BC Hydro has adopted my recommendation in its Demand Side Management (DSM) planning and Load Forecasting processes.

Q11. PLEASE DESCRIBE THE CURRENT RATE-INDUCED CONSERVATION FORECASTING METHOD USED BY BC HYDRO IN ITS DSM PLANNING PROCESS.

A11. BC Hydro uses the following process to estimate the total conservation induced by a new inclining block rate for residential and commercial customers:[1]

- Step 1: For estimating the conservation impact of the new rate, assume both residential and commercial customers will face a two-step inclining block rate design, with average rate increases reflective of BC Hydro's average rate forecasts for these customers.
- Step 2: Use a price elasticity of -0.1 to estimate the total amount of rate-induced conservation for each year of the forecast period.
- Step 3: Decompose the total rate-induced conservation estimate from Step 2 into rate level- and rate design-induced conservation. The decomposition

[1] Rate-induced conservation from industrial customers is estimated by making a site-by-site assessment of the incremental conservation potential that is provided by the Step-2 rate.

assumes that in the absence of the inclining block design, customers will continue to see a flat rate design and have a price elasticity of -0.05. After being placed on inclining block rate structures, however, these customers will become more responsive, with a price elasticity of -0.1.

Q12. DO YOU HAVE ANY CONCERNS REGARDING THE CURRENT ESTIMATION PROCESS AND ELASTICITY ASSUMPTIONS USED BY BC HYDRO TO QUANTIFY RATE-INDUCED CONSERVATION?

A12. I believe that BC Hydro's estimate of the total rate-induced conservation over the forecast period is reasonable, as will be explained in the next Q&A below.

However, I do have one methodological concern with the decomposition of the total conservation estimate (Step 3) into rate level and design components. Even though it is reasonable that the aggregate responsiveness of customers under an inclining block rate will be higher than a flat rate, it is more consistent with the price elasticity literature to assume that "large" customers with usage above the Step-1 threshold will be more price sensitive than "small" customers with usage below the Step-1 threshold.

Q13. CAN YOU DESCRIBE YOUR RECOMMENDED CONSERVATION ESTIMATION APPROACH?

A13. Yes. To compute the conservation effect of a two-step inclining block tariff, I would use the following steps:

- Step 1: Compute the real rate change faced by "small" customers with monthly consumption below the tariff's Step-1 Threshold. This rate change is the new Step-1 rate in real dollar terms less than the existing flat rate.
- Step 2: Find the total sales to "small" customers.
- Step 3: Apply equation (1) to find the conservation effect of the rate change for the total sales found in Step 1. The elasticity assumption should be specific to the "small" customers who may have a different price-sensitivity than the "large" users described in Step 4 below.
- Step 4: Compute the real rate change faced by "large" customers with monthly consumption above the tariff's Step-1 Threshold. This rate change is the new Step-2 rate in real dollar terms less than the existing flat rate. The elasticity assumption should be specific to the "large" customers.
- Step 5: Find the total sales to large customers.
- Step 6: Apply equation (1) to find the conservation effect of the rate change for the total sales found in Step 5.
- Step 7: Find the total conservation effect of the new inclining block tariff as the sum of the two effects obtained in Steps 3 and 6.

Q14. DOES BC HYDRO'S ESTIMATION APPROACH DIFFER FROM THE ESTIMATION APPROACH THAT YOU HAVE JUST DESCRIBED?

A14. Yes it does. To illustrate the difference, consider the example of a two-step inclining block tariff that embodies an average rate increase. The process used by BC Hydro assumes that the nominal Step-1 rate is the existing flat rate escalated at the projected rate of inflation, until the Step-2 rate reaches 12 cents per kWh after the forecast period. Thus, customers with usage below the Step-1 threshold will not see a real rate increase during the forecast years and will not yield rate-induced conservation, *irrespective of their price elasticity*, which is assumed by BC Hydro to be -0.1. BC Hydro estimates that an inclining block tariff's conservation effect will come from the real increase of the marginal rate (i.e., Step-2 rate) faced by the "large" customers, who are also assumed to have a price elasticity of -0.1.

The process I recommend differs from BC Hydro's process because my process does not assume that "small" and "large" customers have the same price elasticity. However, since BC Hydro's assumes that there will be no real rate increase for the "small" customers over the forecast period, the two approaches should yield very similar conservation estimates.

Q15. WHY IS YOUR RECOMMENDED APPROACH NOT USED BY BC HYDRO IN DEVELOPING THE CONSERVATION ESTIMATES FOR ITS 2008 LONG-TERM ACQUISITION PLAN APPLICATION?

A15. My recommended approach can be computationally burdensome when conservation estimation is done for many scenarios, each formed by a combination of a hypothetical rate design and a pair of elasticity assumptions for large and small customers. BC Hydro's chosen method, when applied to a representative sample of residential customers, is less computational burdensome and reasonably accurate.

Q16. DOES BC HYDRO'S USE OF A LOWER PRICE ELASTICITY UNDER A FLAT RATE DESIGN THAN UNDER NEW INCLINING BLOCK RATE DESIGNS ALTER BC HYDRO'S ESTIMATION OF THE TOTAL RATE-INDUCED CONSERVATION?

A16. No, but the assumption can affect the amount of conservation designated as rate level-induced vs. rate design-induced. To see this point, suppose that the assumption of price elasticity under the flat rate is changed from -0.05 to -0.08. While the total rate-induced conservation impact remains unchanged, the assumption change will lead to relatively more rate level-induced conservation and less rate design-induced conservation.

As an illustration, consider the following two hypothetical examples that make use of the following four assumptions:

1. There is a single customer class with total existing sales of 100 TWh per year.
2. The existing tariff is a flat rate. The average real rate increase under the flat rate design for all 100 TWh of the class sales is 5%.
3. The new tariff is a two-step inclining block tariff. Under the new rate design, 70 TWh of the class sales is attributable to the *total* monthly kWh sales to a "large" customer whose monthly consumption is above the Step-1 threshold. Thus, 70 TWh have a marginal price equal to the Step-2 rate, assumed to be 10% above the existing flat rate in real dollar terms. The remaining 30 TWh is attributable to the *total* monthly kWh sales to a

"small" customer whose monthly consumption is below the Step-1 threshold. Thus, 30 TWh have a marginal price equal to the Step-1 rate, assumed to be the existing flat rate in real dollar terms.

4. The price elasticity under the inclining block tariff is -0.1.

The two examples will illustrate how to calculate rate design-induced conservation for two different flat rate elasticity assumptions. Specifically, Example 1 assumes a price elasticity of -0.05 and Example 2 a higher price elasticity of -0.08 under a flat rate design.

Example 1: Elasticity = -0.05 under a flat rate design

When faced with the marginal price equal to the new Step-2 rate, the "large" customers yield an estimated conservation of 0.7 TWh (= 10% real rate increase * -0.1 elasticity * 70 TWh). The "small" customers, however, do not have price-induced conservation because their marginal price remains at the existing flat rate in real dollar terms. Had the flat rate design continued, the -0.05 price elasticity estimate would imply 0.25 TWh of conservation (= -0.05 * 5% rate increase * 100 TWh) for the 5% average real rate increase. Hence, 0.45 TWh (= 0.7 TWh – 0.25 TWh) is the conservation effect of the rate design change from a flat rate to an inclining block.

Example 2: Elasticity = -0.08 under a flat rate design

Since this example has the same -0.1 elasticity under the inclining block rate design as Example 1, its estimated conservation for all customers on the inclining block tariff continues to be 0.7 TWh as shown above. However, had the flat rate design continued, the -0.08 price elasticity estimate would imply 0.40 TWh (= -0.08 * 5% real rate increase * 100 TWh) of conservation for the 5% average real rate increase for all 100 TWh of the total class sales. Hence, 0.3 TWh (= 0.7 TWh – 0.4 TWh) is the conservation effect of the rate design change from a flat rate to an inclining block. This 0.3 TWh rate design-induced conservation is less than the 0.45 TWh estimate when the flat rate price elasticity is assumed to be -0.05 in Example 1.

These two examples confirm that BC Hydro's price elasticity assumption of -0.05 under the flat rate design, is only used for computing the rate design-induced conservation, and it does not affect the total rate-induced conservation impact.

Q17. DOES YOUR APPROACH YIELD ESTIMATES THAT ARE VERY DIFFERENT FROM THOSE FOUND BY BC HYDRO?

A17. No. Under the range of forecasted rate levels considered by BC Hydro, the two methods produce similar estimates for the total conservation impact of a new inclining block rate that embodies an average rate increase. This result is expected because if the nominal Step-1 Rate does not imply a material change in the real rate, the impact of the new rate will come from the large customers; and hence, the two methods would produce very similar results.

3. Price elasticity assumption

Q18. PLEASE DESCRIBE THE BASIS OF YOUR RECOMMEDNED ELASTICITY VALUE OF -0.01.

A18. My recommended value of -0.1 is based on:

- A review of published studies of measured price response results in other jurisdictions with relatively low rates and a winter peaking system, similar to BC Hydro's jurisdiction; and
- The elasticity values used in the Integrated Resource Plans (IRPs) of two electric utilities in the U.S. Pacific Northwest.

Q19. PLEASE DESCRIBE YOUR FINDING FROM YOUR REVIEW OF RESIDENTIAL DEMAND STUDIES.

A19. My review of over 100 studies identifies a wide range of residential price elasticity estimates. A case in point are the residential estimates reported in a 2004 meta-analysis, summarizing (a) 123 short-run estimates that range from -0.004 to -2.01, with an average of -0.35; and (b) 125 long-run estimates that range from -0.04 to -2.25 with an average of -0.85.[2] The variance in these estimates is due to differences in data samples (e.g., time-series versus cross-sectional data, regional versus customer level), estimation methods (e.g., simple versus complicated), and model specifications (e.g., linear versus log-linear, static versus dynamic). Hence, I find that it is more appropriate to use elasticity estimates from

[2] Espey, J. A. and M. Espey (2004) "Turning on the Lights: A Meta-Analysis of Residential Electricity Demand Elasticities." *Journal of Agricultural and Applied Economics* 36: 65-81.

suitably chosen studies that can better match BC Hydro's characteristics of being winter peaking and having comparatively low and stable rates.

Q20. PLEASE DESCRIBE THE RELEVANT STUDIES SUPPORTING THE -0.1 ELASTICITY RECOMMENDATION FOR THE RESIDENTIAL SECTOR.

A20. Table 2 below describes four studies that reflect the results from jurisdictions comparable to British Columbia and cover a price elasticity range from a low of 0.0 in one case to a high of -0.28. These studies bound my recommended -0.1 elasticity and provide evidence that it is reasonable to expect relatively low-cost jurisdictions in the U.S. Pacific Northwest to have elasticities below -0.2.

The first study is a 2005 analysis by Rand Corporation of regional differences in demand for energy. It is chosen because it contains elasticity estimates for Washington, a winter-peaking state next to British Columbia with relatively low rates. This analysis indicates a short-run price elasticity estimate of -0.079 and a long-run estimate of -0.161.

The second study is a 1994 paper reporting the results of a Wisconsin rate experiment designed to test customer price response to inclining block rates. It is chosen because (a) Wisconsin had high winter demand and relatively low rates during the study period, and (b) the rate experiment's focus was customer response to an inclining block tariff. This paper reports low price elasticity estimates: -0.02 for summer and -0.04 for winter.

The third study is a 1994 paper that quantifies the price elasticity of sales by municipal utilities in Ontario. It is chosen because Ontario had low rates in the late 1980s and was a winter peaking jurisdiction.[3] This paper shows low price elasticity estimates between 0.0 to -0.07.

The last study is a 1984 paper reporting the price responsiveness of residential customers in Washington, Oregon, Idaho and Montana. These states had low rates and were winter-peaking during the study period. This paper reports short-run elasticity estimates between -0.11 to -0.28.

Taken together, these four studies suggest that a price elasticity estimate of -0.1 is a conservative but plausible assumption used to quantify the residential consumption response to a new inclining block tariff that embodies an average rate change.

[3] Ontario now has relatively high rates and is becoming a summer peaking utility due to rising cooling loads.

Table 2: Residential demand studies used to support an elasticity value of -0.1

Study	Data sample	Jurisdiction	Short-run elasticity	Long-run elasticity
Bernstein and Griffin (2005)[4]	Annual consumption by state for 1977-2004	Washington	-0.079	-0.161
Herriges and King (1994)[5]	Monthly billing data for a rate experiment for 1500 customers in 1984-85	Wisconsin	-0.02 (Summer) -0.04 (Winter)	Not available
Hsiao and Mountain (1994)[6]	Monthly sales by municipal utility in 1989	Ontario	-0.0 to -0.07	Not available
Henson (1984)[7]	Monthly data for 1077 households observed during 1977-78	Bonneville Power Administration	-0.11 to -0.28	Not Available

Q21. PLEASE DESCRIBE YOUR FINDINGS FROM YOUR REVIEW OF NON-RESIDENTIAL DEMAND STUDIES.

A21. My review of 60 non-residential studies also identifies widely dispersed non-residential price elasticity estimates. A 1984 Rand Report, for example, summarizes 120 price elasticity estimates that are as low as -0.04 and as high as -

[4] Bernstein M. and J. Griffin (2005) “Regional Differences in the Price-Elasticity of Demand for Energy,” (http://RAND.org/pubs/technical_reports/2005/RAND_TR292.pdf, pp.82-84.

[5] Herriges, J. and K. King (1994) "Residential Demand for Electricity Under Block Rate Structures: Evidence from a Controlled Experiment," *Journal of Business and Economic Statistics*, 12(4): 419-430, Table 4.

[6] Hsiao C. and D.C. Mountain (1994) “A Framework for Regional Modeling and Impact Analysis: An Analysis for the Demand for Electricity by Large Municipalities in Ontario, Canada,” *Journal of Regional Science*, 34(3): 361-385, Table 3.

[7] Henson, S. E., (1984) “Electricity Demand Estimates under Increasing-Block Rates,” *Southern Economic Journal* 51(1): 147-156, Table 11.

4.5.[8] A more recent 2004 price elasticity survey summarizes 44 estimates and finds a short-run price elasticity range of +0.11 to -0.33 and a long-run price elasticity range of 0.0 to -1.88.[9] Similar to the residential case, the variance in non-residential estimates is attributable to differences in data samples, estimation methods, and model specifications. Hence, rather than use an average from a broad range, I find that it is more appropriate to use elasticity estimates from suitably chosen studies that better match British Columbia's characteristics of being winter peaking and having comparatively low and stable rates.

Q22. PLEASE DESCRIBE THE RELEVANT STUDIES SUPPORTING THE -0.1 ELASTICITY RECOMMENDATION FOR THE NON-RESIDENTIAL SECTOR.

A22. Listed in Table 3, the first three studies report elasticity estimates by time of use TOU for comparable jurisdictions with relatively low rates and cold climates.[10] They are chosen because I cannot find suitable studies with elasticity estimates for non-TOU pricing that entails a flat or inclining block rate design. That said, the non-TOU average price elasticity estimate is the volume-weighted average of each set of TOU elasticity estimates. Thus, the TOU price elasticities in Table 3 bound their associated non-TOU average price elasticity.

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[8] Acton, J.P. and E.R. Park (1984) *Projecting Response to Time-of-Day Electricity Rates*. RAND Report: N-2041-MD. Appendix B of this report shows a range of -0.04 to -4.5.

[9] Dahl, C. and C. Roman (2004) "Energy Demand Elasticities – Fact or Fiction: A Survey," Working Paper, Colorado School of Mines, Table 5. Based on 11 estimates, this survey reports a range of +0.11 to -0.33 for the short-run price elasticity, yielding an average of -0.14. Based on 44 estimates, the same survey finds a range of 0.0 to -1.88 for the long-run price elasticity, resulting in an average of -0.56.

[10] Even though each sample may contain relatively few customers, the sample size for estimation is large because of the use of daily observations, thus mitigating criticism that the empirical findings in these studies may be unreliable.

The first study is a recently completed 2007 Fraser Institute Report for Ontario’s industrial customers. It shows elasticity values of between -0.1 to -0.14 in response to TOU pricing. The second study is my firm’s 1997 analysis of the nine large industrial customers on Rate Schedule 1821 who participated in BC Hydro’s Real-Time Pricing program. The analysis indicates very limited price responsiveness, with elasticity values between -0.04 and -0.08. The third study is a 1997 paper that estimates the price responsiveness of small commercial firms in Ontario, finding elasticity estimates between -0.04 to -0.09.

In addition to the three studies described above, I have also consulted a 1987 Rand study of large customers served by 10 U.S. utilities in the late 1970s. The study’s extensive data file helps determine if significant price responsiveness exists among large customers across the U.S. The elasticity estimates from this 1987 study are small, ranging from 0.0 to -0.02.

Taken together, the four studies show short-run elasticity values between 0.0 and -0.142, confirming that -0.1 is also a conservative but plausible price elasticity estimate for use in sales forecasting in British Columbia for commercial customers as well.

Table 3: Non-residential demand studies used to support an elasticity value of -0.1

Study	Data sample	Jurisdiction	Short-run elasticity	Long-run elasticity
Angevine and Hrytzak-Lieffers (2007))[11]	Hourly load data for 47 companies from May 2002 to August 2006.	Ontario	-0.102 to -0.142 (on-peak hours)	Not available
Woo (1997)[12]	Daily consumption data by TOU for 9 customers during 04/01/94 to 01/31/97	B.C.	-0.041 (Heavy load hours); -0.083 (Light load hours)	Not available
Ham et al (1997)[13]	15-minute load data for 120 small customers in a TOU experiment from 1985 – 1987.	Ontario	-0.04 to -0.09	Not Available
Acton and Park (1987)[14]	Monthly data by time-of-use for large customers served by 10 utilities in the US during 1977-1980	California, Wisconsin, Illinois and New York	-0.00 to -0.025	Not available

Q23. PLEASE DESCRIBE YOUR REVIEW OF U.S. ELECTRIC UTILITY IRPS.

[11] Angevine, G. and D. Hrytzak-Lieffers (2007) *Ontario Industrial Electricity Demand Responsiveness to Price*, Fraser Institute, p.10.

[12] E3 (1997) Consumption response to optional real time pricing, 04/07/97 memo to Peter Chow, BC Hydro.

[13] Ham, J., *et al*. (1997) "Time-of-Use Prices and Electricity Demand: Allowing for Selection Bias in Experimental Data," *RAND Journal of Economics* 28(0): 113-141, Table 5.

[14] Acton, J.P and R.E. Park (1987) *Response to Time-of-Day Electricity Rates by Large Business Customers: Reconciling Conflicting Evidence*, Rand Report R-3477-NSF, Table 16.

A23. To gauge the reasonableness of my recommended elasticity value of -0.1, I also compare it to those used by Avista Corp. (Avista) and PacifiCorp in their IRPs. Table 4 shows that -0.1 is comparable to those used by Avista and PacifiCorp.

Table 4: Residential elasticity estimates used by Pacific Northwest utilities in their 2007 IRP

Utility	Short-run elasticity	Long-run elasticity
Avista[15]	-0.15 (Residential) -0.10 (Non-residential)	Not available
PacifiCorp [16]	-0.05 (Residential) -0.1 (Non-residential)	-0.09 (Residential)

Q24. BC HYDRO ASSUMES A LOWER ELASTICITY TO COMPUTE THE CONSERVATION EFFECT OF A RATE LEVEL CHANGE UNDER A FLAT RATE DESIGN THAN AN INCLINING BLOCK DESIGN. IS THIS ASSUMPTION REASONABLE?

A24. This assumption asserts that sales response to a change in price is smaller under a flat rate deign than an inclining block design. The assertion is reasonable under the following two conditions:

- Customers respond to marginal prices. That is, a customer with consumption below (above) the Step-1 threshold of a Two-Step inclining block tariff will

[15] Avista Utilities 2007 Electric Integrated Resource Plan, filed with the Idaho Public Utilities Commission, p.2-7, stating "We estimate customer class price elasticity in our computation of electricity and natural gas demand. Residential customer price elasticity is estimated at negative 0.15. Commercial customer price elasticity estimated at negative 0.10."

[16] PacifiCorp 2007 Integrated Resource Plan, Appendices, p.12, p.22. The residential elasticity estimates are found by estimating an econometric equation that explains per customer usage during 1982-2005 using real electricity price, real natural gas price, real household income, weather, and lagged usage. The -0.1 non-residential elasticity is based on the Department of Energy's 2006 Demand Response Report to the Congress.

face and respond to a marginal price equal to the relatively low Step-1 rate (high Step-2 rate).

- There is more marginally priced energy at the Step-2 rate than the Step-1 rate.

Under these two conditions, the conservation impact of an inclining block tariff designed to collect a given average rate increase is larger than the impact of a flat tariff that collects the same rate increase. This is because even though the Step-1 rate is not as high as the new flat rate, the Step-2 rate can exceed the new flat rate by a large amount. Since there is more energy marginally priced at the Step-2 rate, the incremental conservation (above the new flat rate's impact) can more than offset the decremental conservation (below the flat rate's impact). As a result, the conservation impact is smaller under the flat rate than the inclining block rate for a given rate level change.

Q25. IS BC HYDRO'S ELASTICITY ASSUMPTION OF -0.05 REASONABLE FOR COMPUTING THE CONSERVATION EFFECT OF A RATE LEVEL CHANGE UNDER A FLAT RATE DESIGN?

A25. This assumption is reasonable under the two conditions identified in A24. These two conditions are met in BC Hydro's case. Moreover, the -0.05 value is consistent with the low end of the range of elasticity estimates reported in Tables 2-4 above.

Q26. IS BC HYDRO'S ESTIMATION OF THE TOTAL CONSERVATION EFFECT OF A NEW INCLINING BLOCK RATE REASONABLE?

A26. Yes, as I have indicated in A17 above.

4. Conclusion

Q27. WHAT ARE YOUR KEY FINDINGS?

A27. They are as follows:

- BC Hydro should use a single short-run price elasticity to project rate-induced conservation, with separate accounting of the longer term impacts of changes in codes and standards and Power Smart programs.
- BC Hydro should adopt a conservative price elasticity estimate of -0.1 to estimate the combined impact of an average rate increase and a rate design change from a flat rate to an inclining block tariff.
- It is reasonable for BC Hydro to use -0.05 as the price elasticity estimate for decomposing the total conservation impact of an inclining block rate into rate level-induced and rate design-induced conservation, as is done in BC Hydro's 2007 Electric Load Forecast.

Q28. DOES THIS CONCLUDE YOUR TESTIMONY?

A28. Yes.

Ren Orans ren@ethree.com 415.391.5100

ENERGY & ENVIRONMENTAL ECONOMICS, INC. San Francisco, CA
Managing Partner 1993 – Present

Dr. Orans founded this consulting firm in 1993. 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 both pricing and evaluation of grid infrastructure alternatives. 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.

Dr. Orans also used the same data to develop a process called local integrated resource planning (LIRP) using detailed estimates of incremental costs for transmission and distribution planning areas. This work was formalized in his dissertation, *Area-Specific Cost of Electric Utilities: A Case Study of Transmission and Distribution Costs* and his work with the Electric Power Research Institute to document this new LIRP process. This seminal work led to 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 working experience at Pacific Gas and Electric Company, where he was responsible for designing electric rates from 1982 to 1985. He has relied on this background along with his published papers to provide expert testimony on transmission pricing on behalf of BC Hydro (1996, 1997 and 2004), Ontario Power Generation (2000) and Hydro Quebec (2001, 2005). He has also worked extensively on the formulation of Regional Transmission Organizations (Grid West) in the U. S. Pacific Northwest. His current cases include the development of estimates the cost to comply with California's greenhouse gas compliance law (AB32) for the California PUC and the California Air Resource Board (CARB), and the independent evaluation of San Diego Gas and Electric's proposed Sunrise 500 KV transmission line on behalf of the California ISO in a need determination proceeding before the CPUC.

DEPARTMENT OF ENERGY Washington, DC
NATIONAL RENEWABLE ENERGY LABORATORY 1992 – 1993
ELECTRIC POWER RESEARCH INSTITUTE
Lead Consultant

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

PACIFIC GAS & ELECTRIC COMPANY San Francisco, CA
Research and Development Department 1989 – 1991

Dr. Orans developed an economic evaluation method for distributed generation alternatives. The new approach shows that targeted, circuit-specific, localized generation packages or targeted DSM can in some cases be less costly than larger generation alternatives. He also developed the evaluation methodology that led to PG&E's installation of a 500KW photovoltaic (PV) facility at their Kerman substation. This is the only PV plant 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 & ELECTRIC COMPANY San Francisco, CA
Corporate Planning Department 1989 – 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 utilities in California.

PACIFIC GAS & ELECTRIC COMPANY San Francisco, CA
Rate Department Economist 1981 – 1985

As an economist at PG&E, he was responsible for the technical quality of testimony for all electric rate design filings. He was also responsible for research on customers' behavioral response to conservation and load management programs. The research led to the design and implementation of the first and largest residential time-of-use program in California and a variety of innovative pricing and DSM programs.

Education

STANFORD UNIVERSITY Palo Alto, CA
Ph.D. in Civil Engineering

STANFORD UNIVERSITY Palo Alto, CA
M.S. in Civil Engineering

UNIVERSITY OF CALIFORNIA Berkeley, CA
B.A. in Economics

Refereed Papers

Woo, C.K., E. Kollman, R. Orans, S. Price and B. Horii (2008) "Now that California Has AMI, What Can the State Do with It?" Energy Policy, 36, 1366-74.

Lusztig, C., P. Feldberg, R. Orans and A. Olson (2006) "A survey of transmission tariffs in North America," Energy-The International Journal, 31, 1017-1039.

Woo, C.K., A. Olson and R. Orans (2004), "Benchmarking the Price Reasonableness of an Electricity Tolling Agreement," Electricity Journal, 17:5, 65-75.

Orans, R., Woo, C.K., Clayton, W. (2004) "Benchmarking the Price Reasonableness of a Long-Term Electricity Contract," Energy Law Journal, 25: 2, 357-383.

1. *Orans, R., Olson, A., Opatrny, C., (2003) "Market Power Mitigation and Energy Limited Resources," Electricity Journal, 16:2, 20-31.*

2. *Chow, R.F., Horii, B., Orans, R. et. al. (1995), Local Integrated Resource Planning of a Large Load Supply System, Canadian Electrical Association.*

3. *Feinstein, C., Orans, R. (1995) "The Distributed Utility Concept," The Annual Energy Review,1988.*

4. *Woo, C.K., R. Orans, B. Horii and P. Chow (1995), "Pareto-Superior Time-of-Use Rate Options for Industrial Firms," Economics Letters, 49, 267-272.*

5. *Woo, C.K., B. Hobbs, Orans, R. Pupp and B. Horii (1994), "Emission Costs, Customer Bypass and Efficient Pricing of Electricity," Energy Journal, 15:3, 43-54.*

6. *Orans, R., C.K. Woo, R. Pupp and I. Horowitz (1994), "Demand Side Management and Electric Power Exchange," Resource and Energy Economics, 16, 243-254.*

7. *Pupp, R., C.K.Woo, R. Orans, B. Horii, and G. Heffner (1995), "Load Research and Integrated Local T&D Planning," Energy - The International Journal, 20:2, 89-94.*

8. *Woo, C.K., R. Orans, B. Horii, R. Pupp and G. Heffner (1994), "Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution," Energy - The International Journal, 19:12, 1213-1218.*

9. *Orans, R., C.K. Woo and B. Horii (1994), "Targeting Demand Side Management for Electricity Transmission and Distribution Benefits," Managerial and Decision Economics, 15, 169-175.*

10. *Orans, R., C.K. Woo and R.L. Pupp (1994), "Demand Side Management and Electric Power Exchange," Energy - The International Journal, 19:1, 63-66.*

11. *Orans, R., Seeto, D., and Fairchild, W., (1985), "The Evolution of TOU Rates," Pergamon Press.*

Research Reports

1. *Orans, R. Olson, A., Integrated Resource Plan for Lower Valley Energy, December, 2004.*

2. *Orans, R., Woo C.K., and Olsen, Arne, Stepped Rates Report, prepared for BC Hydro and filed with the BCUC, May, 2003.*

3. *Orans, R., Woo, C.K, and B. Horii (1995), Impact of Market Structure and Pricing Options on Customers' Bills, Report submitted to B.C. Hydro.*

4. *Horii, B., Orans, R., Woo, C.K., (1994) Marginal Cost Disaggregation Study, Report submitted to PSI Energy.*

5. *Woo, C.K., L. Woo and R. Orans (1995), Rationing and Area-Specific Generation Costs, Report submitted to Pacific Gas and Electric Company.*

6. *Orans, R., C.K. Woo and C. Greenwell (1994), Designing Profitable Rate Options Using Area- and Time-Specific Costs, Report No. TR-104375, Electric Power Research Institute.*

7. *Singer, J., Orans, R., Energy Efficiency Lending, A Business Opportunity for Fannie Mae, Report submitted to Fannie Mae.*

8. *Orans, R., Feinstein, C. et. al., (1993), Distributed Utility Valuation Study, submitted to the Electric Power Research Institute, the National Renewable Energy Laboratory, and PG&E.*

9. *Orans, R., Pupp, R., (1993), Menomonee Falls Case Study, Submitted to Wisconsin Electric Power Corporation.*

10. *Orans, R. and C.K. Woo (1992), Marginal Cost Disaggregation Study, Report submitted to Wisconsin Electric Power Corporation.*

11. *Orans, R., C.K. Woo, J.N. Swisher, B. Wiersma and B. Horii (1992), Targeting DSM for Transmission and Distribution Benefits: A Case Study of PG&E's Delta District, Report No. TR-100487, Electric Power Research Institute.*

12. *Orans, R., Swisher, J., Duane, T., (1989), Lessons Learned from U.S. Electric Utilities, Prepared for the Department of Energy for the Peoples Republic of China.*

13. *Orans, R., Area-Specific Marginal Costing for Electric Utilities: A Case Study of Transmission and Distribution Costs (1989) PhD Thesis, Stanford University.*

14. *Orans, R., (1987)The Risk of Sales Forecasts: Controllable through Indexation and Careful Disaggregation, Submitted to Stanford University and Pacific Gas and Electric Company.*

15. *Woo, C.K. and R. Orans (1983), Transferability of Other Utilities' Time of Use Experiments to PG&E's Service Schedule D-7, Pacific Gas and Electric Company Reports filed with the California Public Utilities Commission.*

Conference Papers

1. *Orans, R. Evaluating Generating Resources based on a Equivalent Reliability Methodology, 2nd Annual Resource Planning Symposium, January, 2004, Vancouver, Canada.*

2. *Martin, J., Orans, R., Knapp, K., “DG Economics and Distribution Rate Design” (2000), Western Electric Power Institute, Distributed Generation and the Utility Distribution System Conference, March 22-23, Reno, NV.*

3. *Orans, R. (1997), “Getting the Transmission Prices Right,” Facilitating Cross Border Trade, New Mexico.*

4. *Orans, R. (1997), “Deregulation on the Mainland, What is Happening and What is Not, PCEA Conference, Hawaii.*

5. *Swisher, J., Orans, R., (1995), "A New Utility DSM Strategy Using Intensive Campaigns Based on Area Specific Costs," ECEEE 1995 Summer Study.*

6. *Orans, R., Greenwell, C., (1995), "Designing Profitable Rate Options Using Area and Time-Specific Costs," Prepared for EPRI, Annual DSM Review, Dallas, Texas.*

7. *Orans, R, Integrated Local Area Planning, (1995), Prepared for NELPA and presented in Calgary.*

8. *Orans, R., Local Area Planning for Profit, "Annual Review of Distributed Resource Studies," Prepared for EPRI, Lake George, New York.*

9. *Orans, R., C.K. Woo, B. Horii and R. Pupp, (1994), "Estimation and Applications of Area- and Time-Specific Marginal Capacity Costs," Proceedings: 1994 Innovative Electricity Pricing, (February 9-11, Tampa, Florida) Electric Research Power Institute, Report TR-103629, 306-315.*