Expert report on Hydro One Distribution's density-based rates

Prepared for the School Energy Coalition (SEC)

October 29, 2009

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1. Introduction

Q. Please state your name, title, and business affiliation.

A. My name is C.K. Woo. I am a Senior Partner of Energy and Environmental Economics, Inc. (E3), a consulting firm located at 101 Montgomery Street, Suite 1600, San Francisco, California 94104, USA.

Q. Please state your qualifications and experience.

A. I specialize in public utility economics, applied microeconomics, and applied finance. With over 25 years of experience in the electricity industry, I have testified and prepared expert testimony for use in regulatory and legal proceedings in California, British Columbia and Ontario. I have also filed declaration for and testified in arbitration in connection to contract dispute.

My current research includes electricity deregulation, rate design, procurement, demand response and rationing, integrated resource planning, and transmission pricing. I have published over 80 refereed articles in such scholarly journals as *Energy Policy, The Energy Journal, Energy, Electricity Journal, Resource and Energy Economics, Energy Economics, IEEE Transactions on Power Systems, Economics Letters, Journal of Regulatory Economics, Journal of Public Economics,* and *Quarterly Journal of Economics.*

Recognized by *Who's Who in America*, *Who's Who in Finance and Business*, and *Who's Who in Science and Engineering*, I am an associate editor of *Energy* and a guest editor of a 2006 special issue on *Electricity Market Reform* *and Deregulation* and a forthcoming special issue on *Demand Response Resources*. I am also a member of the editorial board of *The Energy Journal* and have served as their guest editor for a 1988 special issue on *Electricity Reliability*.

I hold a Ph.D. (Economics) from the University of California, Davis. Prior to joining E3, I was Associate Professor of Economics at City University of Hong Kong. My curriculum vitae, included as Attachment 1 to this report, further describes my qualifications, experience and publications.

Q. What is the purpose of your report?

A. I was retained by the School Energy Coalition (SEC) to address the following questions:

- What methods are appropriate in cost allocation and rate design to reflect potential locational cost differences at Hydro One Distribution (HOD)?
- How may an urban/rural cost allocation be developed using available information?

Q. What are your key findings?

A. My key findings are as follows:

- HOD's density-based rates should be simplified to urban/rural rates, in obeisance of "the principles of acceptability, lack of controversy and ease of understanding."[1] HOD's density-based rates are uncommon when compared to the industry practice of locational ratemaking in Canada; and uncommon rates tend to invite controversies. Moreover, HOD's density-based rates use criteria that are more complicated for customers to understand than urban/rural rates set according to municipal boundaries.

- HOD's density-based rates are not adequately supported by a reasonably done cost allocation analysis. This finding echoes the OEB's directive in its December 18 2008 Decision (p.31): "[a]ccordingly, the Board directs Hydro One to provide a more detailed analysis on the relationship between density and cost allocation to the Board." Thus, HOD's density-based rates could be less reflective of cost-causation than urban/rural rates.

- An urban/rural cost allocation can be developed using available information. If a sufficiently large urban/rural cost difference is found, adopting urban/rural rates may yield the following benefits: (a) HOD will reduce the number of residential rate schedules from three to two; (b) the new rates will be easier to understand by customers than the density-based rates; and (c) the new rates will be cost-reflective.

[1] OEB (2009) *Rate Classification for Electricity Distribution Customers*, Staff Discussion Paper EB-2007-0031, January 29, 2009, p.19.

2. What methods are appropriate in cost allocation and rate design to reflect HOD's locational cost differences?

Q. Are HOD's density-based rates common in Canada?

A. No. As indicated in Table 1, locational rates used by Canadian electric utilities are based on geographic boundaries, not customer densities. Three utilities in Table 1 have urban/rural rates: NB Power, Maritime Electric, and Cornwall Electric. NB Power and Maritime Electric classify urban customers as those located in incorporated cities, towns and villages with population over 2,000. Cornwall Electric classifies urban customers as those within the city limits of Cornwall.

My answer here corroborates HOD's consultant report, *Principles for Defining and Allocating Costs to Density-Based Sub-Classes* prepared by Elenchus Research Associates Inc. (ERA Report):

- "ERA has been unable to find any other jurisdiction or electricity distributor that has defined distinct urban and rural classes based on explicit density criteria. As a result, examples from other jurisdictions do not provide insight into possible alternatives to the Hydro One approach for defining classes based on explicit density criteria." (p.1)

- "It is not uncommon; however, for customers inside municipal boundaries to be classified as urban (sometimes with a minimum population threshold for the municipality) and those outside the urban municipal boundaries to be classified as rural." (p.1)

Table 1: Locational rates as of October 15 2009 in Canada, with urban/rural rates in **bold**

Province	Utility	Description
Alberta	ATCO Electric	Rates are divided by 29 rural electrification associations. The difference in rates is reflected in the O&M Adder.
Alberta	EPCOR Energy Services	Rates are divided among specific regions: City of Edmonton, FortisAlberta, and Town of Ponoka. City of Edmonton and Town of Ponoka are distinguished by municipal boundaries and the FortisAlberta region makes up the remainder of the EPCOR service area.
British Columbia	BC Hydro	Rates are divided by 3 zones designated Zone I, Zone I B and Zone II. Zones are made up of integrated service area and specific districts.
New Brunswick	**NB Power**	**The residential rate is different for urban and rural customers. Urban customers are those customers located in incorporated cities, towns and villages with population over 2,000.**
Newfoundland and Labrador	Newfoundland and Labrador Hydro	Rates are divided by the Island Interconnected service area, Happy Valley-Goose Bay Interconnected service area, and Labrador City Wabush Interconnected service area.
Ontario	CNP Inc.	Separate rates exist for Fort Erie and Port Colborne, the two communities served.
Ontario	**Cornwall Electric**	**All service class rates are divided by urban and rural. Urban customers are those within the city limits of Cornwall.**
Ontario	Festival Hydro	Residential rates are divided between the community of Hensall and all other service territory.
Ontario	Niagara Peninsula Energy Inc.	Rates are divided among two service areas: Niagara Falls and Peninsula West. Peninsula West residential rates are divided between urban and suburban.
Ontario	Powerstream	Rates are divided among the region of York and the region of Barrie/Simcoe County.
Ontario	Veridian	Rates are divided among the town of Gravenhurst and all other service territory.
Prince Edward Island	**Maritime Electric**	**The residential rate is different for urban and rural customers. Urban customers are those customers located in incorporated cities, towns and villages with population over 2,000.**

Q. Except for Cornwall Electric, the Ontario local distribution companies (LDCs) in Table 1 plan to replace their locational rates with uniform rates. Does these LDCs' plan alter your previous answer?

A. No, because these LDCs' plan does not change the fact that when a Canadian utility uses locational rates, those rates are based on geographic boundaries, not customer densities.

Q. Are density-based rates common in the US?

A. No. I am not aware of any density-based rates in the US. A utility with a multi-state service territory, however, is likely to have locational rates. For example, Pacific Power, which serves Washington, Oregon, and California, has rates that vary by state. A utility with a large service territory may also have locational rates. For example, Pacific Gas and Electric Company, serving Northern California, has residential inclining block rates with block quantities that vary by weather zone.

Q. Are HOD's density-based rates more difficult for customers to understand than urban/rural rates?

A. Yes, because customers can better understand municipal boundaries than HOD's urban classification criteria of "60 customers per km and a minimum critical mass of 3,000 contiguous customers" (OEB's December 18 2008 Decision, p.23). A case in point is Cornwall Electric, which defines urban customers as those within city limits. Cornwall Electric's definition is transparent and informative when compared to HOD's density-based criteria.

According to Bonbright, a sound rate structure should have "[t]he related 'practical' attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application;"[2] In terms of simplicity and understandability, urban/rural rates are sounder than density-based rates.

Q. According to Bonbright, a sound rate structure should have "[f]reedom from controversies as to proper interpretation."[3] How do HOD's density-based rates fare under this criterion?

A. In terms of freedom from controversies, HOD's density-based rates do not fare well for two reasons. First, Table 1 above shows that they are an exception to the Canadian industry practice of locational ratemaking. Uncommon rates tend to invite controversies. Second, the OEB's December 18 2008 Decision (p.31) indicates the inadequacy of HOD's cost allocation used to set the density-based rates. Inadequately supported rates tend to invite controversies.

Q. Besides simplicity and understandability, what are the other benefits from replacing HOD's density-based with urban/rural rates?

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[2] Bonbright. JC, AL Danielsen and DR Kamerschen (1988), Principles of Public Utility Rates, Public Utilities Reports, Inc., VA: Arlington, p.384.
[3] Bonbright. JC, AL Danielsen and DR Kamerschen (1988), Principles of Public Utility Rates, Public Utilities Reports, Inc., VA: Arlington, p.384.

A. The replacement will reduce the number of HOD's residential rate schedules from three to two. Moreover, municipality-based urban/rural rates will likely reduce customer re-classification because municipal boundaries tend to be more stable than area-specific densities.

Q. The OEB's 01/29/2009 Staff Discussion Paper EB-2007-0031: *Rate Classification for Electricity Distribution Customers* (p.19) states: "Locational costs vary with other factors besides density, yet the Board and stakeholders have generally rejected locational rates or locational classes. Staff suggests that the principles of acceptability, lack of controversy and ease of understanding are important considerations in this discussion." What is your view on this statement?

A. I agree that "locational costs vary with other factors besides density". I also agree with "the principles of acceptability, lack of controversy and ease of understanding". However, I caution against an outright rejection of urban/rural rates for HOD because of the current lack of empirical evidence on the urban/rural cost difference. To the extent that the urban/rural cost difference is large, urban/rural rates should follow the principle of fairness.

According to the Bonbright, "[f]airness of the specific rates in the apportionment of total costs of service among the different ratepayers [aims] to avoid arbitrariness and capriciousness and to attain equity ....".[4] Also stated in the same OEB Staff Discussion Paper (p.4), "[t]he principle of fairness in rate design

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[4] Bonbright. JC, AL Danielsen and DR Kamerschen (1988), Principles of Public Utility Rates, Public Utilities Reports, Inc., VA: Arlington, p.383.

can be expressed as the drive to reduce cross-subsidization. Traditionally, rate classes are set to try to ensure that inter-class fairness is achieved by grouping customers so that like customers can be treated in a like manner. Inter-class cross subsidization is addressed by reducing the revenue to cost ratio for each class to unity as closely as possible."

Q. What is your view on HOD's density-based rates' reflection of cost-causation?

A. My view is that HOD's density-based rates are based on the urban classification criteria of 60 customers per km and a minimum critical mass of 3,000 contiguous customers. HOD has not provided evidence on whether the chosen criteria have yielded more reasonable cost differentiation among its customer classes than alternatively defined criteria.

My view here is corroborated by the OEB's directive in its December 18 2008 Decision (p.31): "[a]ccordingly, the Board directs Hydro One to provide a more detailed analysis on the relationship between density and cost allocation to the Board. This should consider whether the number of Residential and General Service customer classes in the new class structure is adequate, and whether the customer class demarcations approved in this Decision offer the best reflection of cost causation. The study should include consideration of alternative density weightings, with descriptions and criteria for comparing alternatives. Comparisons with the costs of distributors similar in size and location to Acquired Distributors would also be useful. The Board requires that Hydro One submit this information in its next cost of service application."

Q. In your view, has HOD fully complied with the OEB's directive?

A. No, because the ERA Report, as its title suggests, only focuses on the principles of density-based cost allocation. My view is confirmed by HOD's response to SEC's Interrogatory #48 List 1: "Yes, Hydro One confirms that the study is not intended to be in full compliance with the Board's direction and further steps would be required."

In particular, the ERA Report does not contain empirical evidence to address the specific topics raised by the OEB:

- Whether the number of Residential and General Service customer classes in the new class structure is adequate;
- Whether the customer class demarcations approved in this Decision offer the best reflection of cost causation;
- Consideration of alternative density weightings, with descriptions and criteria for comparing alternatives; and
- Comparisons with the costs of distributors similar in size and location to Acquired Distributors.

Q. What customer-related drivers are commonly used to explain the cost difference between two areas?

A. Based on my review of the econometric cost studies in Table 2, these drivers are total MWH volume, number of customers, and line-km. From these drivers, other metrics can be found (e.g., load density = MWH per customer; customer density = number of customers per line-km). The general finding is that a LDC's average cost (= $ per customer or $ per MWH) declines when the LDC's load density or customer density rises. This finding is also supported by the cost analyses referenced by the studies in Table 2.

Table 2: Statistical cost studies reviewed

Study	Data
Lowry, MN, L Getachew and S Fenrick (2008) Benchmarking the Costs of Ontario Power Distributors, Final Report submitted to the OEB, Pacific Economics Group, WI: Madison	Ontario LDC in 2002-2006
Yatchew, A (2000) "Scale economies in electricity distribution: a semi-parametric analysis," Journal of Applied Econometrics 15: 187-210.	Ontario LDC in 1993-1995
Lowry, MN, L Getachew and D Hovde (2005) " Econometric benchmarking of cost performance: the case of U.S. power distributors," Energy Journal 26(3): 75-92.	U.S. power distributors in 1991 - 2002
Filippinia M and J Wild (2001) "Regional differences in electricity distribution costs and their consequences for yardstick regulation of access prices," Energy Economics 23: 477-488.	Swiss electricity distribution utilities in 1988-1996
Goto M and T Sueyoshi (2009) "Productivity growth and deregulation of Japanese electricity distribution" Energy Policy 37: 3130-3138.	Distribution divisions in Japanese electric power companies in 1983–2003
Huang YJ, KH Chen and CH Yang (2009) "Cost efficiency and optimal scale of electricity distribution firms in Taiwan: An application of metafrontier analysis," Energy Economics forthcoming.	Distribution units in Taiwan's electric power sector in 1997–2002

Q. Can you provide an example to illustrate the possible cost difference between urban and rural areas?

A. Yes. My example assumes the following cost regression:

$$ln\ Y \quad = \quad b_0 + b_1\ ln\ X_1 + b_2\ ln\ X_2 + b_3\ ln\ X_3 \qquad (1)$$

where $ln\ Y$ = natural-log of total cost; $ln\ X_1$ = natural-log of total MWH; $ln\ X_2$ = natural-log of total number of customers; and $ln\ X_3$ = natural-log of total line-km. The regression's intercept estimate is b_0 and slope coefficient estimates are (b_1, b_2, b_3). The slope coefficient estimates are elasticity estimates. If $b_1 = 0.4$, a 1-percent difference in total MWH would alter total cost by 0.4 percent. The other slope coefficient estimates have similar interpretations.

Computing the percent-difference in total costs between an urban and a rural area requires data on $\Delta\ ln\ X_1$ = percent-differences in total MWH, $\Delta\ ln\ X_2$ = percent-difference in total number of customers, and $\Delta\ ln\ X_3$ = percent-difference in total line-km. Using such data, the percent-difference in total costs is:

$$\Delta\ ln\ Y \ = \quad b_1\ \Delta\ ln\ X_1 + b_2\ \Delta\ ln\ X_2 + b_3\ \Delta\ ln\ X_3, \qquad (2)$$

the elasticity-weighted sum of percent-differences in area-specific drivers.

To inject empirical content into my example, consider the OM&A cost benchmarking study recently done for Ontario LDC that provides average elasticity values (Lowry, Getachew and Fenrick, 2008, pp.52-53). Solely for the purpose of illustration, Table 3 below assumes a set of *hypothetical* percent-differences in cost drivers because the actual percent-differences are yet to be determined. These assumed driver differences result in a 5.61% OM&A expense difference, which does not account for the capital cost difference that may exist between an urban area and a rural area. Section 3 below will show how one may determine the total cost difference between an urban area and a rural area.

Table 3: Example of percent-difference in total OM&A costs between an urban area and a rural area

Variable	Elasticity estimate	*Hypothetical* percent-difference [= (Urban value / Rural value) - 1]	Elasticity estimate × percent-difference
Total number of customers	0.491	10	4.91
Total MWH volume	0.366	10	3.66
Total line-km	0.094	-10	-0.94
Input price index	1.399	0	0
Percent of distribution line underground	-0.096	10	-0.96
10 year customer growth / output index	-0.106	10	-1.06
Canadian Shield (binary)	0.011	0	0
Total	--	--	5.61

3. How may an urban/rural cost allocation be developed using available information?

3.1 Process

Q. How may an urban/rural cost allocation be developed using available information?

A. The allocation may be developed using the following 7-step process:

- Step 1: Assume an urban/rural definition based on municipal boundaries.
- Step 2: Use billing data to find area-specific values for the total number of customers and total MWH volume.
- Step 3: Use distribution data to find area-specific values for total line-km and percent of distribution line underground.
- Step 4: Apply the model in Lowry, Getachew and Fenrick (2008, p.53, Table 3) to compute the log of total OM&A expenses for the urban area.
- Step 5: Repeat Step 4 to compute the log of total OM&A expenses for the rural area.
- Step 6: Estimate the percent-difference in total costs, using the OM&A expense difference based on the results from Steps 4 and 5.

- Step 7: Solve for the urban/rural cost allocation using the result from Step 6 and the revenue requirement for the customers subject to the urban/rural rates.

Q. Please remark on Steps 1 to 3.

A. HOD's system-level data are already available (Lowry, Getachew and Fenrick, 2008, Appendix Table A). These three steps split the system-level data into urban and rural values.

Q. Please further explain Steps 4 and 5.

A. Table 3 of Lowry, Getachew and Fenrick (2008, p.53) has the regression coefficient estimates of the log of total OM&A expenses. Step 4 applies these estimates to the urban-specific values of the regression's explanatory variables to predict the log of total OM&A expenses for HOD's urban area. An example of this computation is equation (1), which shows how the natural-log of costs may vary with its drivers. Step 5 repeats the exercise to predict the value for HOD's rural area.

Q. What assumption do these two steps implicitly make?

A. The assumption is that the regression of Lowry, Getachew and Fenrick (2008, p.53) is a reasonable representation of HOD's OM&A expense data. This assumption reflects "that it may be possible to benchmark HON with reasonable accuracy using Ontario data and econometric methods. This would reduce the need for HON to file additional benchmarking studies, based on other data sources, that are costly to prepare and review" (Lowry, Getachew and Fenrick, 2008, p.57).

Q. Please remark on Step 6.

A. The regression of Lowry, Getachew and Fenrick (2008, p.53) is for total OM&A expenses. Thus, it can only provide the percent-difference in total OM&A expenses between an urban and a rural area. Step 6 assumes the percent-difference in total costs (including capital) is the same as the percent-difference the total OM&A expense difference. As this assumption may be inaccurate, Section 3.2 below discusses an alternative approach.

Q. Please further explain Step 7.

A. To further explain this step, I first define the following:

- R = Known revenue requirement for the combined total sales subject to urban and rural areas;
- R_U = Allocated cost for the urban area (which is to be estimated);
- R_R = Allocated cost for the rural area (which is to be estimated); and
- X = Urban/rural percent-cost difference from Step 6 = $(R_U / R_R) - 1$, implying $R_U = R_R (1 + X)$.

Now, the total revenue requirement is:

$$R = R_U + R_R. \qquad (3)$$

From Step 6, I know

$$R_U \quad = \quad R_R\,(1 + X). \tag{4}$$

Substituting equation (4) into equation (3) yields:

$$R \quad = \quad R_R\,(1 + X) + R_R \quad = \quad R_R\,(2 + X). \tag{5}$$

Thus, I find $R_R = R\,/\,(2 + X)$, the cost allocated to the rural area. I then compute $R_U = R - R_R$, the cost allocated to the urban area.

3.2 Alternatives

Q. What if the OM&A expense regression in Lowry, Getachew and Fenrick (2008, p.53) does not accurately reflect a LDC's total cost?

A. The urban/rural total cost difference found in Step 6 will be inaccurate.

Q. How may one remedy this inaccuracy?

A. One may use the regression in Lowry, Getachew and Fenrick (2008, p.53) to compute the urban/rural per MWH difference in OM&A expenses. This will enable an OM&A expense allocation between the urban and rural areas.

To allocate HOD's capital costs, one may use (a) line-km values by area for distribution line costs; (b) installed capacity values by area for costs of substations and transformers; and (c) numbers of customers by area for service hook-up costs (e.g., secondary line drops and meters). As the urban area's asset age may differ from the rural area's asset age, adjustment to the area-specific values may be necessary to reflect the age difference. The following example illustrates this point:

> Example: Distribution line cost allocation. Suppose the total capital cost for distribution lines is $100M. The urban area has 100 line-km and the rural area 200 line-km. Without considering age, 1/3 [= 100 line-km / (100 line-km + 200 line-km)] of the $100M is allocated to the urban area and 2/3 to the rural area. However, the average age of urban lines is 20 years, and that of rural lines is 40 years. Suppose the estimated line life is 50 years. The remaining-life-weighted line-km for the urban area is 60 [= 100 line-km * (1 - 20 years /50 years)] and for the rural area is 40 [= 200 line-km * (1 - 40 years /50 years)]. Hence, the age-adjusted allocation is $60M [= 60 adjusted line-km / (40 adjusted line-km + 60 adjusted line-km)] for the urban area and $40M (= $100M - $60M) for the rural area.

Q. What alternative methods of cost allocation are proposed in the ERA Report?

A. The ERA Report (p. 4) proposes the following alternatives:

- "All things considered, it is my view that the most practical and cost effective approach is likely to be to use sample data to derive an estimate of the average cost (or cost differential) of serving urban and rural customers under the definitions that are approved for future use."

- "In the alternative, it may be appropriate to rely on engineering analysis to establish an appropriate rate differential between urban and rural customers that isolates the density-related cost differential for urban and rural service."

Q. What is your view of these alternatives?

A. If done properly, these alternatives would replace Steps 4-6 of my 7-step process. The results of these alternatives, however, should be reviewed for their reasonableness.

Q. What should the review do?

A. The review should address the following topics:

- Sample size. To obtain results representative of HOD's large service territory, a large sample is preferable to a small sample.

- Data quality. To obtain accurate results, verified data from HOD primary sources is preferable to unverified data from non-HOD secondary sources.

- Choice of allocation weights. The weights should reflect how costs move with the underlying drivers. For example, line-km by area provide more accurate weights than total numbers of customers by area for allocating distribution line costs by area.

- Sensitivity of results. If the results are highly sensitive to the choice of data sample or allocation weights, they signal the need for careful scrutiny and justification of the chosen data sample or allocation weights.

- Empirical comparison. This provides a final check of the results' reasonableness. It can be done in two ways. First, the OM&A expense results by area can be compared to those derived from a cost benchmarking study such as Lowry, Getachew and Fenrick (2008). Second, the average cost ($ per MWH cost or $ per customer cost) for the urban (rural) area can be compared to the average cost of other LDCs that mainly serve customers inside (outside) municipal boundaries.

Attachment 1

Curriculum vitae of Dr. C.K. Woo

C.K. Woo ck@ethree.com 415.391.5100 ext. 310

Dr. Woo specializes in public utility economics, applied microeconomics, and applied finance. With over 20 years of experience in the electricity industry, he has testified and prepared expert testimony for use in regulatory and legal proceedings in California, British Columbia and Ontario. He has also filed declaration for and testified in arbitration in connection to contract dispute. Dr. Woo's current research includes electricity deregulation, procurement, risk management, demand response and rationing, avoided cost estimation, integrated resource planning, value of service reliability, and transmission pricing.

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

Dr. Woo has published over 80 refereed articles on electricity deregulation, procurement, risk management, pricing, rationing, integrated resource planning, value of service reliability, applied microeconomics, and applied finance. These articles appear in such scholarly journals as *Energy Policy, Energy Law Journal, The Energy Journal, Energy, Electricity Journal, Resource and Energy Economics, Energy Economics, IEEE Transactions on Power Systems, Water Resources Research, Managerial and Decision Economics, OMEGA, Journal of Regulatory Economics, Journal of Public Economics, Quarterly Journal of Economics, Journal of Economic Psychology, Economics Letters, Journal of Business Finance and Accounting,* and *Pacific Basin Finance Journal.* Recognized by *Who's Who in America, Who's Who in Finance and Business,* and *Who's Who in Science and Engineering*, Dr. Woo is an associate editor of *Energy* and their guest editor of a special issue on electricity market reform and deregulation and a special issue on demand response resources. He is a member of the editorial board of *The Energy Journal* and has served as their guest editor for a special issue on electricity reliability.

CITY UNIVERSITY OF HONG KONG Hong Kong, China

Associate Professor, Department of Economics and Finance 1991 – 1993

Dr. Woo analyzed the economic impacts of supply shortage on consumers, resulting in a series of publications on water and electricity rationing. He also performed specification tests of econometric models of stock returns. As a consultant, he performed marginal costing, demand-side-management evaluation and reliability planning which led to several publications on local integrated resource planning and T&D costing.

ANALYSIS GROUP, INC. San Francisco, CA

Senior Associate 1987 – 1991

Dr. Woo was responsible for applied microeconomics, outage cost estimation, reliability planning, and electricity pricing. He was the primary consultant to several utilities for outage cost estimation and reliability differentiation. His extensive publications in these two areas are widely cited by other researchers. He also performed economic analysis of mergers and acquisition with a primary focus on the anti-trust aspect of market power, with the resulting findings filed with both state and federal courts.

PACIFIC GAS AND ELECTRIC COMPANY San Francisco, CA

Rate Economist 1985 – 1987

Dr. Woo revamped PG&E's research on outage cost estimation whose findings appear in a special issue of *The Energy Journal* focusing on electricity reliability. He also participated in PG&E's preparation of the General Rate Cases.

SACRAMENTO MUNICIPAL UTILITIES DISTRICT Sacramento, CA

Econometrician 1984 – 1985

Dr. Woo was responsible for demand estimation and load forecasting. The results from his study guided SMUD's resource planning.

PACIFIC GAS AND ELECTRIC COMPANY San Francisco, CA

Rate Economist 1982 – 1984

Dr. Woo was responsible for time-of-use (TOU) demand analysis and TOU pricing mandated by the CPUC. This work resulted in a performance award from PG&E and several publications.

CALIFORNIA ENERGY COMISSION Sacramento, CA

Research Assistant 1978 – 1982

Mr. Woo was the primary author of the life cycle costing model used by the CEC to analyze solar energy and other DSM measures. He testified before the CPUC on the economics of solar financing.

Education

UNIVERSITY OF CALIFORNIA Davis, CA

Ph.D. in Economics

Thesis: The non-parametric approach to production analysis: a case study on a regulated electric utility.

QUEEN'S UNIVERSITY Kingston, Ontario

M.A. in Economics

CONCORDIA UNIVERSITY Montreal, Quebec

B. Comm. in Economics

Languages

Chinese

Citizenship

United States

Research

Special issues

1. *Woo, C.K. and L. Greening, editors (2009) Special Issue on Demand Response Resources, Energy, forthcoming.*

2. *Woo, C.K., L.C.H. Chow and N. Lior, editors (2006) Special Issue on Electricity Market Reform and Deregulation, Energy, 31:6-7.*

3. *Munasinghe, M., C.K. Woo and H.P. Chao, editors (1988) Special Electricity Reliability Issue, The Energy Journal, 9.*

Refereed Publications

Electricity Deregulation

1. *Woo, C.K., I. Horowitz and A. Tishler (2009) "A Critical Assessment of the Macau SAR Government's Proposed Post-2010 Regulatory Regime," Electricity Journal, 22:3, 87-96.*

2. *Woo, C.K. and J. Zarnikau (2009) "Will Electricity Market Reform Likely Reduce Retail Rates?" Electricity Journal, 22:2, 40-45.*

3. *Tishler, A., I. Milstein and C.K. Woo (2008) "Capacity Commitment and Price Volatility in a Competitive Electricity Market," Energy Economics, 30, 1625-1647.*

4. *Tishler, A., J. Newman, I. Spekterman and C.K. Woo (2008) "Assessing the Options for a Competitive Electricity Market in Israel," Utilities Policy, 16, 21-29.*

5. *Tishler, A. and C.K. Woo (2007) "Is Electricity Deregulation Beneficial to Israel?" International Journal of Energy Sector Management, 1(4): 322-341.*

6. *Woo, C.K., I. Horowitz and A. Tishler (2006) "A Critical Assessment of the Hong Kong Government's Proposed Post-2008 Regulatory Regime for Local Electricity Utilities," Energy Policy, 34, 1451-1456. (Lead article)*

7. *Woo, C.K., A. Olson, I. Horowitz and S. Luk (2006) "Bi-directional Causality in California's Electricity and Natural-Gas Markets," Energy Policy, 34:15, 2060-2070.*

8. *Woo, C.K., M. King, A. Tishler and L.C.H. Chow (2006) "Costs of Electricity Deregulation," Energy, 31:6-7, 747-768. (Lead article after Guest Editors' Introduction, one of the 25 most downloaded articles)*

9. *Tishler, A. and C.K. Woo (2006) "Likely Failure of Electricity Deregulation: Explanation with Application to Israel," Energy, 31:6-7, 845-856.*

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