ENERGY REGULATION QUARTERLY

VOLUME 5, ISSUE 2 2017

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The mission of the Energy Regulation Quarterly is to provide a forum for debate and discussion on issues surrounding the regulated energy industries in Canada including decisions of regulatory tribunals, related legislative and policy actions and initiatives and actions by regulated companies and stakeholders. The Quarterly is intended to be balanced in its treatment of the issues. Authors are drawn principally from a roster of individuals with diverse backgrounds who are acknowledged leaders in the field of the regulated energy industries and whose contributions to the Quarterly will express their independent views on the issues.

EDITORIAL POLICY

The Quarterly is published by the Canadian Gas Association to create a better understanding of energy regulatory issues and trends in Canada.

The managing editors will work with CGA in the identification of themes and topics for each issue, they will author editorial opinions, select contributors, and edit contributions to ensure consistency of style and quality.

The Quarterly will maintain a "roster" of contributors who have been invited by the managing editors to lend their names and their contributions to the publication. Individuals on the roster may be invited by the managing editors to author articles on particular topics or they may propose contributions at their own initiative. From time to time other individuals may also be invited to author articles. Some contributors may have been representing or otherwise associated with parties to a case on which they are providing comment. Where that is the case, notification to that effect will be provided by the editors in a footnote to the comment. The managing editors reserve to themselves responsibility for selecting items for publication.

The substantive content of individual articles is the sole responsibility of the contributors.

In the spirit of the intention to provide a forum for debate and discussion the Quarterly invites readers to offer commentary on published articles and invites contributors to offer rebuttals where appropriate. Commentaries and rebuttals will be posted on the Energy Regulation Quarterly website.

ENERGY REGULATION QUARTERLY

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EDITORIAL

Rowland J. Harrison, Q.C. and Gordon E. Kaiser
Managing Editors

Alberta's electricity market is undergoing extensive changes in order to implement certain elements of the province's *Climate Leadership Plan*, announced on November 22, 2015.[1] The main components of that plan are:

- an accelerated phase-out of coal-fired power generation by 2030;
- an economy-wide carbon dioxide tax;
- an absolute cap on oil sands emissions; and
- a methane gas emissions reduction plan.[2]

The province has repeatedly referred to the plan as a selling point for the approval of oil pipelines to tidewater.[3]

Approximately 39 per cent of Alberta's installed electricity generation capacity is from coal and achieving the phase-out of all coal-fired power generation by 2030 is an ambitious goal. The target has nevertheless been legislated in the *Renewable Electricity Act,*[4] which was tabled in November 2016.

In their article on "Alberta's Evolving Electricity Market – An Update on Recent Changes and Developments", Kimberly Howard and Gordon Nettleton review the restructuring of the market, from a fully deregulated regime to a hybrid system that incorporates capacity payment mechanisms.

Electricity market reform is also being initiated in Ontario by the Independent Electricity System Operator (IESO), the first significant overhaul of that market since it was first implemented 15 years ago. The scope of the planned market reform is reviewed by Johannes Pfeifenberger *et al.* in their article "Reforming Ontario's Wholesale Electricity Market: The Costs and Benefits." The article is based on work undertaken by the Brattle Group for the IESO. The analysis concluded that the reform initiative "can mitigate or eliminate numerous existing inefficiencies associated with the current market design and provide substantial net benefits to the province."

In their article titled "Do Manufacturing Firms Relocate in Response to Rising Electric Rates?", Ahmad Faruqui and Sanem Sergici conclude that industrial relocation clearly is not just driven by the price of electricity and that many factors go into the relocation decision, including other costs of doing business such as labor costs and taxes, access to raw materials and access to markets. The conclusions are based on variations in industrial rates across the U.S. but the authors "expect similar conclusions would flow from a review of Canadian data." *ERQ* hopes that this piece will prompt the generation of data and some analysis on this

1 Government of Alberta, *Climate Leadership Plan* (Edmonton: 22 November 2015), online: <http://www.alberta.ca/climate-leadership-plan.cfm>.
2 Ernest & Young LLP, "Alberta climate change leadership plan announcement" (Calgary: 2015), online: <http://www.ey.com/Publication/vwLUAssets/Alberta-climate-change-leadership-plan-announcement/$FILE/Alberta-climate-change-leadership-plan-announcement.pdf>.
3 See, for example, Rick McConnell, "Alberta's climate-change plan selling point for pipelines, Rachel Notley says" *CBC News* (19 July 2016), online: <http://www.cbc.ca/news/canada/edmonton/alberta-s-climate-change-plan-selling-point-for-pipelines-rachel-notley-says-1.3686055>.
4 Bill 27, *Renewable Electricity Act*, 2nd Sess, 29th Leg, Alberta, 2016.

side of the border.

Oil and gas exploration offshore from British Columbia has had a somewhat checkered history, including moratoriums on drilling and on tanker traffic off the northern coast. The status of these moratoriums has sometimes been unclear. As this issue of *ERQ* goes to press, however, the federal government has introduced legislation to formalize the moratorium on tanker traffic. The history of the moratorium and the proposed legislation are reviewed by David Bursey and Charlotte Teal in their article "Proposed Oil Tanker Moratorium Act – a brief look at the history of the moratorium". The authors conclude that restricting options for export will add cost and complication to the developing Canada's oil resources for export. The long-standing debate will continue as the legislation proceeds through Parliament.

Mechanisms for pricing carbon dioxide emissions are of course all directed at reducing those emissions. However, the effectiveness of such mechanisms requires further empirical study, which in turn suggests transparency in their application would be useful. In a recent decision, the Ontario Energy Board declined to require the inclusion of cap and trade charges as a separate line item in customer bills, notwithstanding that prospective usefulness, and notwithstanding widespread support for such transparency. Moin Yahya concludes in "'Cap and Trade' and Price Transparency: a Comment on the OEB's Decision in EB-2015-0363" that the Board missed a valuable opportunity to contribute to the science surrounding customer behavior with respect to emissions.

Finally in this issue of *ERQ*, one of your editors, Rowland Harrison, reviews *DYSFUNCTION: Canada after Keystone XL,* by Dennis McConaghy, a retired senior executive of TransCanada Corp. The review suggests that *Dysfunction* is an important contribution to the current debate about the review process for pipelines and should be read widely by politicians, policy-makers, regulators, industry and concerned citizens. ■

ALBERTA'S EVOLVING ELECTRICITY MARKET – AN UPDATE ON RECENT CHANGES AND DEVELOPMENTS

Kimberly Howard and Gordon Nettleton***

Throughout 2016, a number of key developments directly affected Alberta's power sector. Most of these developments arose in connection with the implementation of the *Climate Leadership Plan*[1] ("Climate Plan") by the Government of Alberta (the "Province"). The Climate Plan was originally announced in November of 2015, and, among other things, it promised an economy-wide carbon price and a legislated cap on oil sands emissions.

For the power sector, the driving objective set out in the Climate Plan is to phase out emissions from coal-fired generation by 2030. Two-thirds of the existing electricity produced from coal is intended to be replaced with electricity from renewable sources and one-third with natural gas. To date, the Province has taken a number of steps toward achieving these goals. Significantly, on November 23, 2016, the Province announced the restructuring of Alberta's electricity market, from a fully deregulated regime to a hybrid system that incorporates capacity payment mechanisms.[2]

This article provides a high-level overview of the recent developments in Alberta, including a summary of the initiatives arising out of the Climate Plan, followed by a more detailed discussion of the Alberta Electric System Operator's ("AESO") initiative to develop a new capacity electricity market.

1. Current Market Snapshot

Alberta is one of the few jurisdictions in the world with an "energy-only" market. This means that Alberta generators only recover the wholesale price of electricity. Investors are only able to recover invested capital if they can leverage high-priced hours, and in this way, the energy-only system contains the risk of supply instability and may not promote investment in generation facilities and, in particular, renewable energy sources.

The following are some key statistics of Alberta's electricity market:[3]

- Approximately 39 per cent of Alberta's installed electricity generation capacity is from coal, almost 44 per cent is from natural gas, nine per cent is from wind, and the remaining capacity is from water,

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**Gordon Nettleton is a partner with McCarthy Tetrault and co-leads the firm's National Energy Regulatory Practice Group. He regularly appears before provincial and federal energy administrative tribunals and assists clients in matters that concern electricity and pipeline rates and facilities applications and issues involving Aboriginal and environmental law.

1 Government of Alberta, *Climate Leadership Plan* (Edmonton: Alberta Environment and Parks, 20 November 2015), online: <https://www.alberta.ca/climate-leadership-plan.aspx>.

2 Government of Alberta, *Consumers to benefit from stable, reliable electricity market* (Edmonton: 23 November 2016), online: <https://www.alberta.ca/release.cfm?xID=44880BD97DCDC-D465-4922-25225F9F43B302C9>.

3 Government of Alberta, *Energy Statistics* (Edmonton: December 2015), online: <http://www.energy.gov.ab.ca/Electricity/682.asp>.

biomass and waste heat forms of generation.

See figure 1 below.

- As of May 2016, the AESO estimated the changes depicted below to Alberta's future generation capacity based on the anticipated policy changes.[4] Although the estimates are based on the assumption of 4,200 megawatts ("MW") of installed renewable capacity, the Province subsequently announced a target of 5,000 MW from wind, solar and hydro projects by 2030.

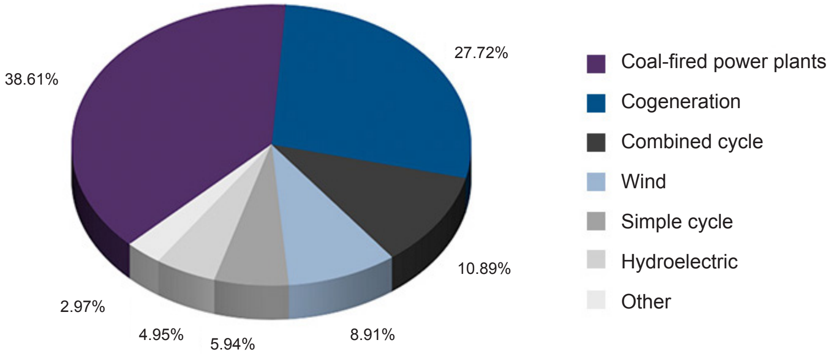
See figure 2 below.

2. The Climate Plan

As indicated above, for the power sector, the Climate Plan seeks to replace two-thirds of the existing coal-fired electricity with renewable energy and one-third with natural gas. To achieve its goals, the Province has taken a number of steps, including:

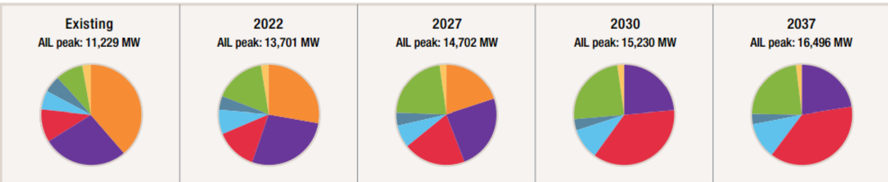
Phase-out of coal emissions by 2030: The Climate Plan's goal is to replace these units with two-thirds renewable energy and one-third natural gas generation. The Province legislated its "30 by '30" target in the *Renewable Electricity Act*,[5] which was tabled in November 2016. On November 24, 2016, Alberta

Figure 1



Source: AESO, *Electricity in Alberta*, as of August 2016.

Figure 2



	Existing %	Existing MW	2022 %	2022 MW	2027 %	2027 MW	2030 %	2030 MW	2037 %	2037 MW
Coal-fired	39%	6,289	28%	5,420	20%	4,491	0%	0	0%	0
Cogeneration	28%	4,502	27%	5,353	24%	5,406	24%	5,548	23%	5,690
Combined-cycle	11%	1,716	13%	2,626	20%	4,446	36%	8,541	38%	9,451
Simple-cycle	6%	996	8%	1,499	7%	1,642	10%	2,307	11%	2,877
Hydroelectric	5%	894	5%	894	4%	894	4%	894	4%	894
Wind	9%	1,463	16%	3,213	22%	4,963	24%	5,663	23%	5,663
Other	3%	428	2%	469	2%	469	2%	469	2%	469
Total capacity		16,288 MW		19,474 MW		22,311 MW		23,422 MW		25,044 MW

Source: AESO 2016 Long-term Outlook, as of May 2016.

4 AESO, *AESO, 2016 Long-term Outlook*, online: <https://www.aeso.ca/download/listedfiles/AESO-2016-Long-term-Outlook-WEB.pdf>.
5 Bill 27, *Renewable Electricity Act*, 2nd Sess, 29th Leg, Alberta, 2016.

announced its decision to provide transition payments to TransAlta Corporation, Capital Power Corporation, and ATCO Ltd., as part of the process to phase out coal-fired emissions on or before December 31, 2030. Under the proposed scheme, these three companies are expected to receive annual payments totaling $1.1 billion over the course of 2016 to 2030. The Province announced that these payments will not be funded by consumer electricity rates, but rather by Alberta's carbon levy on industrial emissions.

Renewable Energy Program: The *Renewable Electricity Act* also empowers the AESO to administer a competitive bid process for its Renewable Electricity Program ("REP"). Under the REP, successful bidders enter into a Renewable Electricity Support Agreement ("RESA") with the AESO, which will provide a twenty-year indexed renewable energy credit, structured akin to a Contract for Difference, to cover any difference between the participant's bid price for the project and the pool price of energy in the market. The AESO officially launched the first competition (Round 1) of the REP on March 31, 2017 with a Request for Expressions of Interest (the REOI).[6] In addition to continuing its stakeholder consultation and information sessions, the AESO released a revised draft of the RESA and provided the key dates for REP Round 1. The full form of RESA is expected to be released to project bidders during the Request for Qualifications Stage.

See figure 3 below.

Economy-wide carbon price: Changes in 2015 to the *Specified Gas Emitters Regulation*[7] ("*SGER*") significantly increased the cost of emissions for large industrial emitters (those that emit 100,000 tonnes or more of greenhouse gases). Such facilities are subject to the following costs of compliance under *SGER*:

Site-specific emissions intensity reduction targets:	Emissions payments for each tonne over the facilities' reduction targets:
• 12% in 2015	• $15 in 2015
• 15% in 2016	• $20 in 2016
• 20% in 2017	• $30 in 2017

The Province also introduced a *Carbon Competitiveness Regulation*,[8] basing emissions intensity credits on a comparison with the most efficient natural gas generator.

Province-wide carbon levy: On January 1, 2017, under the *Climate Leadership Act*, the Province imposed a province-wide carbon levy, with the purpose of "provid[ing] for a carbon levy on consumers of fuel to be effected through a series of payment and remittance obligations

Figure 3

AESO ISSUANCE OF REOI	March 31, 2017
REOI question submission deadline	April 11, 2017
REOI information session	April 18, 2017
REOI concludes & EOI Forms due	April 21, 2017
AESO ISSUANCE OF RFQ TO INTERESTED PARTIES	April 28, 2017
RFQ submissions due	June 16, 2017
AESO evaluation of RFQ submissions and selection of qualified respondents	June to September 2017
AESO ISSUANCE OF RFP TO PROPONENTS	September 15, 2017
RFP submissions due	October 13, 2017
Selection of successful proponent(s) and execution of RESA(s)	December 2017
Target commercial operation date	December 2019

Source: AESO, *Request for Expressions of Interest for the First Renewable Electricity Program Competition REP Round 1*, Section 2.1 at p 4.

6 AESO, *Request for Expressions of Interest – For the First Renewable Electricity Program Competition REP Round 1* (Calgary: 31 March 2017), online: <https://www.aeso.ca/assets/Uploads/REP-Round-1-REOI-033117.pdf>.
7 *Specified Gas Emitters Regulation*, Alta Reg 139/2007.
8 Alberta, *Climate Leadership Report to the Minister* (Edmonton: Alberta Climate Change Advisory Panel, 2015), online: <http://www.alberta.ca/documents/climate/climate-leadership-report-to-minister.pdf>.

that apply to persons throughout the fuel supply chains."[9] The carbon levies are imposed upon various enumerated transactions across the fuel value chain. Revenues from the carbon levy will be used for: (i) initiatives to reduce greenhouse gas emissions, or more broadly, to support Alberta's ability to adapt to climate change; or (ii) to fund rebates or adjustments related to the levies. Namely, carbon pricing revenue will be invested back into Alberta for clean research and technology, green infrastructure and to help finance the AESO's REP. The Province announced that the carbon tax will also be used for an "adjustment fund" to help individuals and families adjust to the levy, and to help small business, First Nations and people working in the coal industry.

Legislated cap on oil sands emissions: The oil sands sector accounts for approximately one-quarter of Alberta's annual emissions and these facilities are currently charged a levy based on each facility's historical emissions under the *SGER*. On December 14, 2016, the new *Oil Sands Emissions Limit Act*[10] came into force. This Act places a cap on emissions from oil sands production of 100 Megatonnes. The legislation also contemplates certain exceptions in respect of cogeneration emissions, upgrading emissions, and potential discretionary exemptions by regulation (likely to accommodate new technological developments). While the Act itself came into force, its regulations have not yet been developed and will be required to provide the full scope and application of this new legislation.

Methane emissions reduction plan: Alberta intends to cut methane emissions by 45 per cent from 2014 levels by 2025.[11] The Province's largest source of methane emissions is from the oil and gas industry (from venting, fugitive emissions from natural gas driven pneumatics and leaks, and flaring). The former Climate Change and Emissions Management Corporation, now Emissions Reduction Alberta ("ERA"), has earmarked a total of $40 million to help advance technologies to reduce methane emissions in Alberta, providing successful applicants with up to a maximum of $5 million.[12] Project proposals were due on March 30, 2017 with ERA expected to release its decision in June of 2017.[13]

3. Alberta's Capacity Market

Over the next 14 years, the Province has estimated that it will need up to $25 billion of new investment in electricity generation to support, in part, the growing electricity needs of the Province and to implement its plan to phase out coal-fired generation and meet its target of 30 per cent renewable electricity capacity by 2030.[14]

Accordingly, current and potential energy investors as well as the AESO have recommended that Alberta transition to a capacity power market regime, which is expected to promote stability in the price and supply of electricity and investment in energy. This recommendation can be found in the AESO's report entitled, Alberta Wholesale Electricity Market Transition Recommendation[15] ("AESO Capacity Report").

Under the proposed market scheme, Alberta will incorporate mechanisms to compensate power producers for their generation capacity. Alberta's electricity market will therefore be comprised of three separate markets: (i) a market for energy; (ii) the ancillary services market; and (iii) a market for capacity, in which generators will agree to have availability to supply electricity when required. Each of these markets produce separate revenue streams: (i) energy payments, which are paid to the generator for electricity that is purchased; and (ii) capacity payments, which are paid to the generator for making generation capacity available on demand.

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9 *Climate Leadership Act*, SA 2016, c C-16.9, s 3.
10 *Oil Sands Emissions Limit Act*, SA 2016, c O-7.5.
11 Alberta, *Climate Plan, Reducing Methane Emissions* (Edmonton: Alberta Environment and Parks), online: <https://www.alberta.ca/climate-methane-emissions.aspx >.
12 Alberta, Press Release, *New "ERA" of Climate Innovation Targets Methane Pollution* (Edmonton: Government of Alberta, 2016), online: <http://www.alberta.ca/release.cfm?xID=43663196ECDB0-D667-25D7-74C379B20D4BC055>.
13 Emissions Reduction Alberta, *Addressing the Methane Challenge – Full Project Proposal Guidelines* (Edmonton: Government of Alberta), online: <http://www.eralberta.ca/apply-docs/era-methane-full-project-proposal-guidelines.pdf>.
14 Government of Alberta, *Electricity* (Edmonton: Alberta Energy), online: <http://www.energy.alberta.ca/Electricity/electricity.asp>.
15 AESO, *Alberta Wholesale Electricity Market Transition Recommendation* (Calgary: 2 October 2016), online: <https://www.aeso.ca/assets/Uploads/Albertas-Wholesale-Electricity-Market-Transition.pdf > ("*AESO Capacity Report*").

a. Why the Transition to a Capacity Market?

By letter dated January 10, 2017,[16] Alberta Energy requested that the AESO lead the technical design of the capacity market, including an evaluation of the AESO itself in order to identify necessary charges to the energy and ancillary services products markets, to ensure system reliability.[17]

Within the AESO Capacity Report, the AESO concluded that maintaining the status quo (i.e. no change to the current energy-only market rules, products or design) will not attract a sufficient amount of investment in firm, dispatchable generation to ensure an adequate supply as Alberta transitions away from coal and towards renewable generation.[18] Upon landing on its recommendation for a capacity market, the AESO analyzed, with reference to the Province's desired outcomes, the alternative options to remedy this failure. At a high level, Alberta Energy and the AESO's desired outcomes are:

- A ***reliable and resilient system*** (i.e. compatibility with managing coal phase-out, compatibility with increased interties, integration of renewable generation and new technologies, variability of the reserve margin and sufficient supplied adequacy);

- ***Environmental performance*** (i.e. compatibility with the REP, resiliency of market to environmental policy, compatibility with increased cogeneration, energy efficiency, micro and distributed generation, carbon prices and future expansion of renewable energy);

- ***Reasonable costs to consumers*** (i.e. stable prices, reasonable cost of delivered energy, maintaining fair efficiency and openly competitive market operation, compatibility with changes to the regulated rate option, maintaining reasonable transmission costs, and fundamentally does not alter the market);

- ***Economic development and job creation*** (i.e. impact on trade exposed or key industries, enabling economic growth and achieving other social objectives such as support for particular demographics, locations or industrial policy); and

- An ***orderly transition*** (i.e. minimizing disruption and costs).

For context, the other options explored by the AESO included: (i) enhancements to the energy-only market (e.g. increasing the price cap from $1,000 to $5,000); (ii) long-term contracts like those implemented in Ontario; and (iii) the return to a regulated cost of service structure.

As discussed in detail within the AESO Capacity Report, the AESO ultimately recommended a capacity market because it:[19]

- Ensures reliability as Alberta's electricity system evolves and will specifically compensate for firm generation;

- Increases stability of prices;

- Provides greater revenue certainty for generators;

- Maintains competitive market forces and drives innovation and cost discipline; and

- Supports implementation of Climate Leadership Plan initiatives and is adaptable to future policy evolution.

b. Timeline for the Capacity Market

- Alberta's capacity market will be developed in consultation with stakeholders, and will be implemented by 2021.

- The AESO has estimated that the design of the market will take two years to complete, with an additional year to finalize legal contracts and to set up a procurement process.

- The first capacity contracts are expected

16 Government of Alberta, *Letter to Mr. David Erickson, President and CEO of the AESO* (Edmonton: 10 January 2017), online: <https://www.aeso.ca/assets/Uploads/capacity-market-design-AESO-mandate-letter-Jan-10-2017.pdf>.
17 *Ibid*.
18 *AESO Capacity Report*, *supra* note 15 at 16.
19 *AESO Capacity Report*, *ibid* at 40-41.

to be formed at least three years after the design process begins.

- Accordingly, the earliest date that capacity procured through the initial auction would be in service will likely be in 2024.

4. Design of the Capacity Market - Issues and Developments to Monitor

The possible implications of the power market overhaul on Alberta's energy landscape will need to be considered in light of other commitments recently announced by the Province, such as its renewable energy initiatives. At present, some issues to consider include:[20]

- **Role of the Regulators:** Achieving an orderly transition to a capacity market and its design and implementation will require legislative changes, regulatory rule making (i.e. new ISO Rules and Tariffs) and oversight by the applicable regulators. As such, Alberta's electricity regulators and agencies, including the Alberta Utilities Commission ("AUC"), Alberta Market Surveillance Administrator and the Balancing Pool could play a greater role.

  We anticipate that the AUC will play an important role, including with respect to both the market rule development process and facility applications. For example, as development activity continues in advance of future rounds of the REP and competitive capacity auctions, we anticipate a corresponding increase in the number of facility approval applications submitted to the AUC. During the AUC's review and approval of the increasing number of facility applications, it will be interesting to watch how the AUC considers and addresses evidence regarding recurrent themes, including those related to noise, wildlife and health effects. Public involvement in energy infrastructure has been on the forefront of recent energy development and is of significant importance in Alberta and throughout Canada. An area to monitor is whether the AUC's "directly affected" test[21] for standing to participate in proceedings will remain or whether it will be changed to a more inclusive standard to foster greater public participation.

- **Price Stability:** Although there are many direct benefits to consumers from capacity markets, such as the reduction of price spikes, consumers risk incurring increased costs. The Province recently announced its commitment to protecting consumers from volatile prices by implementing a price cap of 6.8 cents per kilowatt hour from June 2017 to June 2021.[22] However, as the cap on electricity prices and the implementation of power capacity payments are unlikely to overlap, the implications of the capacity power market on consumer prices remains uncertain.

- **Overlap and Interplay with Other Initiatives:** How the capacity market will interact with the principles of the energy-only market and specifically the principles legislated within the Fair, Efficient and Open Competition Regulation[23] ("FEOC") will be critical to watch. Specifically, whether and how the FEOC principles will be applied to the various relationships between generators participating in the Alberta market, including the successful bidders from both the REP and the auction for capacity contracts, and how such incentives will be addressed with incumbent generators who already invested, built and operate natural gas and renewable generation facilities in Alberta should be carefully observed.

- **Supply Reliability:** The capacity market provides incentives for electricity

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20 See also Kimberly Howard, Beverly Ma & George Vegh, "The New Current: Alberta Announced Overhaul of Electricity Market" Canadian Energy Perspectives, Developments in Energy and Power Law (24 November 2016), online: Canadian Energy Perspectives Blog <http://www.canadianenergylawblog.com/2016/11/24/the-new-current-alberta-announces-overhaul-of-electricity-market/>.

21 *Alberta Utilities Commission Act*, SA 2007, c A-37.2, s 9; AUC Rule 001, Rules of Practice, s 11.

22 Government of Alberta, Price cap to protect consumers from volatile electricity prices (Edmonton: 22 November 2016), online: < https://www.alberta.ca/release.cfm?xID=4487283D35A59-070B-5A1F-76A7FB63D2CA149D>.

23 Alta Reg 159/2009.

generators to supply the power pool, as well as with the means to invest in renewable energy sources. It remains to be seen whether the market overhaul will remedy possible gaps in Alberta's power supply, especially during the period of coal phase-out, and whether it will reinforce Alberta's Climate Plan. ■

REFORMING ONTARIO'S WHOLESALE ELECTRICITY MARKET: THE COSTS AND BENEFITS

*Johannes Pfeifenberger, Kathleen Spees, Judy Chang, Walter Graf, and Mariko Geronimo Aydin**

Overview

The Independent Electricity System Operator (IESO) of Ontario's wholesale electricity market is about to initiate a major reform of its market design. This initiative will be the first significant overhaul of Ontario's wholesale electricity market since it was first implemented 15 years ago.[1] The planned market reform will include significant changes to: (1) increase the efficiency of the "energy" component of the wholesale markets, (2) introduce a number of features to improve the system's operating flexibility, and (3) implement an incremental capacity auction to support the investments needed to maintain the reliability of Ontario's electricity supply. This coordinated set of market reforms has been termed "Market Renewal" and represents the culmination of many years of analysis and observation by the IESO, the Ontario Market Surveillance Panel (MSP), and Ontario electricity sector stakeholders.

Our recently-completed analysis of market reform impacts, undertaken with extensive consultation of IESO stakeholders, shows that the initiative can mitigate or eliminate numerous existing inefficiencies associated with the current market design and provide substantial net benefits to the province.[2] Based on these results, the IESO and its stakeholders decided to proceed with developing a revised market design in a manner that will maximize available benefits, mitigate implementation risks, and prepare the province's wholesale power market for meeting future customers' needs while supporting public policy priorities.

The key findings of our analysis include:

- The estimated benefits of Market Renewal significantly outweigh estimated implementation costs, with a present value of net benefits ranging from $2.2 billion to $5.2 billion over the next decade. These province-wide benefits will be shared by customers and suppliers.

*Johannes Pfeifenberger, Kathleen Spees and Judy Chang are Principals, Mariko Geronimo Aydin is a Senior Associate, and Walter Graf is an Associate at The Brattle Group, an economic consulting firm with offices in Toronto, Boston, Washington DC, San Francisco, New York, London, Rome, Madrid, and Sydney. This article is based on work undertaken for Ontario's Independent Electricity System Operator (IESO). We acknowledge the important contributions of IESO staff, members of the Market Renewal Working Group, and IESO stakeholders. Brattle Research Analysts Peter Cahill, James Mashal, and John Imon Pedtke contributed to the analysis of benefits for this study. Vikki Harper, William Schwant, and Ken Donald of Utilicast contributed to estimating IESO implementation costs for the proposed Market Renewal initiatives. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group or its clients.

1 See IESO postings related to Market Renewal, online: <http://www.ieso.ca/sector-participants/engagement-initiatives/engagements/market-renewal>.

2 Pfeifenberger et al, *The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project,* The Brattle Group, prepared for IESO (20 April 2017), online: <http://www.ieso.ca/sector-participants/engagement-initiatives/engagements/market-renewal>.

- The benefits from Market Renewal are likely to grow over time as Ontario's electricity sector continues to decarbonize, as contracts expire, and as the sector becomes more distributed in nature.

- Market Renewal will better prepare Ontario for the future by creating a competitive framework for effectively incorporating new and emerging technologies.

- The IESO and stakeholders have substantial opportunities to enhance the benefit-to-cost ratio of the Market Renewal by learning from the experiences of other jurisdictions and applying lessons learned to Ontario's unique context.

The Need for Market Renewal

The current wholesale market was originally designed to coordinate the operations of nuclear, hydro, and fossil-fueled resources, with coal-fired generation providing about 25 per cent of Ontario's total energy needs and providing the bulk of the system flexibility. The limitations of this market design were recognized by the Market Design Committee who originally developed the system, and the design was supposed to be a temporary solution that would have transitioned to a system with "nodal pricing" over an 18-month period after initial implementation. Contrary to those former plans, this transitional design has now been in place for one and a half decades.

Over time, patches and temporary improvements have been layered onto the foundational design, but the existing system has nevertheless become increasingly inefficient. These inefficiencies have been extensively documented and analyzed by the IESO, the MSP, and independent observers.[3] In 2014, Ontario retired its last coal-fired generating plant as a part of a concerted effort by the province to decarbonize the electricity sector.[4] Non-emitting generation resources (particularly nuclear, biomass, wind, and solar) and new natural gas generation have replaced most of the coal-fired generation. The changing supply mix and increasing flexibility needs have amplified the challenges with the existing market design. Looking forward, the challenges are likely to intensify, making the existing system increasingly inefficient and costly. Further, with the adoption of new technologies that introduce additional operational complexities and the continued rise of participation at the distribution level will require significant improvements to the market design overall.

While the specific implementation details of the Market Renewal Program will still need to be developed, the general features of Market Renewal that the IESO and stakeholders have identified can be categorized into three workstreams:

- **Energy:** Move to a market with a single schedule for operations and financial settlement, including locational marginal pricing for suppliers, improved generation commitment and dispatch in real time, and a financially-binding day-ahead market.

- **Operability:** Increase system flexibility and improve utilization of interties with neighboring systems to reduce the cost associated with surplus-generation conditions, variable renewable generation uncertainties, and the need to curtail resources.

- **Capacity:** Improve procurement of resources to meet the province's resource adequacy needs through an incremental capacity auction that stimulates competition from all qualified supply resources in a technology-neutral manner.

These reforms will increase the extent to which Ontario relies on transparent market-based mechanisms to provide electricity to all consumers. Experiences from other North American power markets that have already addressed challenges similar to those in Ontario

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3 For example, see Ontario Energy Board, *Market Surveillance Panel: Congestion Payments in Ontario's Wholesale Electricity Market: An Argument for Market Reform*, (Toronto: December 2016), online: <http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_CMSC_Report_201612.pdf>.

4 See Ontario Ministry of Energy, *The End of Coal: An Ontario Primer on Modernizing Electricity Supply* (Toronto: December 2015), online: <http://www.energy.gov.on.ca/en/archive/the-end-of-coal/>.

show that the proposed market reform will help support a more efficient electricity sector.

Expected Benefits of Market Renewal

We estimated the benefits of each of the three Market Renewal workstreams based on stakeholder input, existing studies of the Ontario market, analyses of similar market redesign efforts in other North American power markets over the last decade, and an assessment of Ontario's unique characteristics. For each workstream, similar reforms in other markets have proven to yield efficiency benefits that significantly outweigh costs. Energy market reforms in MISO, CAISO, ERCOT, and SPP between 2005 and 2014 implemented many of the same elements currently being considered in Ontario.[5] Similarly, studies of operability and intertie enhancements in CAISO, ERCOT, MISO, NYISO, PJM, and ISO-NE have quantified significant benefits the IESO's operability workstream could potentially capture.[6] Furthermore, experience in other markets has shown that capacity auctions can attract substantial quantities of low-cost capacity resources. In particular, the U.S. markets of PJM, ISO-NE, and NYISO have successfully relied on capacity markets to meet their reliability needs cost-effectively for more than a decade.[7] Combining Ontario-focused analyses with the real-world experiences from other markets—after recognizing and controlling for differences across markets—provides a comprehensive picture of the potential benefits and risks associated with Market Renewal.

The primary benefits of Market Renewal are associated with:

- **Fuel, Emissions, and Operations and Maintenance (O&M) Cost Savings.** The current market does not fully account for all costs and system constraints in price-setting, resource commitment, and generation dispatch. As a result, the province is not taking full advantage of its lowest-cost resources. Market Renewal will reduce operating costs by improving the system's ability to identify and utilize the lowest-cost resources, including wind, solar, nuclear, hydro, storage, demand response, and interties.

- **Reduced Curtailment/Spilling of Non-Emitting Resources.** The current market neither efficiently utilizes existing resources nor incentivizes innovative solutions to meet system flexibility needs. Improved market design will avoid excessive costly curtailment of the province's non-emitting wind, solar, and nuclear, and hydro resources.

- **Increased Export Revenues and Reduced Import Costs.** A reformed energy market and optimized interties will increase the efficiency of trading with neighboring power markets. Such improvements will allow for increased imports of lower-cost generation and enable Ontario suppliers to export more power whenever export revenues exceed Ontario's generation costs.

- **Investment Cost Savings.** Transitioning to a more market-based capacity procurement process, combined with enhanced energy and ancillary market incentives, will increase competition to meet system needs at lower investment cost. A technology-neutral approach will level the playing field for existing and new resources, including innovative technologies that have been left out of the capacity procurement process traditionally.

- **Reduced Gaming Opportunities, Administrative Complexity, and Unwarranted Transfer Payments.** The current system does not align generation dispatch with market prices, resulting in costly uplift payments. These payments

5 See section III of our April 20th report, *supra* note 2, for a thorough discussion of the energy market reforms in these markets, how they compare with those being considered in Ontario, and how we used studies of benefits in these markets to estimate potential benefits in Ontario.

6 See section IV of our April 20th report for details, *supra* note 2.

7 PJM's capacity market was implemented in 2007, ISO-NE's in 2010, NYISO's in 2006, and MISO's more recently in 2013. For a review of the experience with the first decade of capacity market operations, see Kathleen Spees, Samuel A. Newell & Johannes P. Pfeifenberger, "CapacityMarkets—Lessons Learned from the First Decade" (2013) 2:2 Economics of Energy & Environmental Policy, online: <http://www.iaee.org/en/publications/eeeparticle.aspx?id=4>. For more discussion of the experience in other capacity markets and how these findings shaped our analysis of benefits in Ontario, see section V of our April 20th report, *supra* note 2.

in part reflect the inefficiencies and administrative burden of operations for both the IESO and market participants; and they create incentives for some market participants to profit from the design flaws. A more competitive market design can eliminate these inefficiencies and gaming opportunities.

- **Enhanced Competition and Innovation.** Improved market design will yield market prices that accurately reflect market conditions which, in turn, will support competition among a broad set of traditional and non-traditional resources to minimize system costs and encourage innovation.

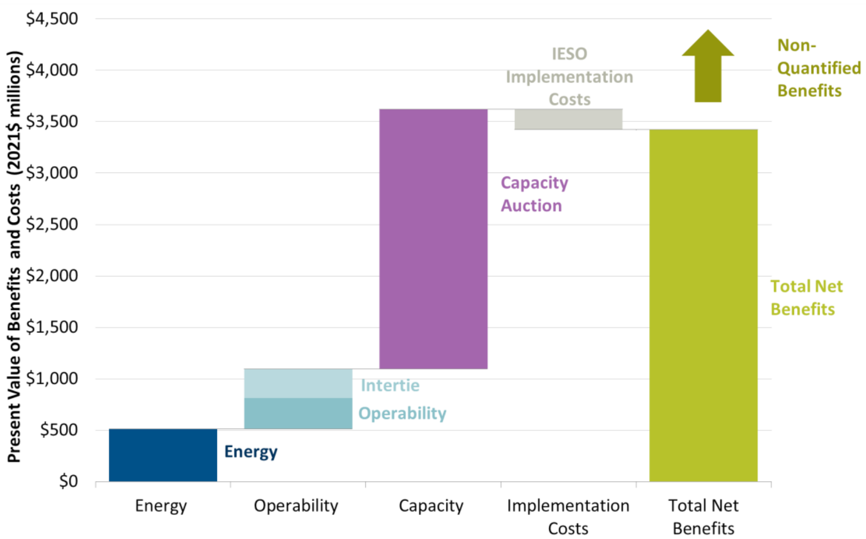
- **Alignment with Provincial Policy Goals.** Market Renewal will create an improved platform for enabling market evolution in support of Ontario's policy objectives and changing market fundamentals.

Figure 1 summarizes our estimates of the benefits and costs of Market Renewal. As shown, the present value of estimated benefits between 2021 and 2030 is approximately $510 million from energy market reforms, $580 million from operability reforms, and $2.5 billion from capacity auction reforms. Realized benefits will continue beyond 2030 and will grow over time as more existing contracts expire. The benefits could be greater than we have estimated if the existing contracted resources are more responsive to market prices than assumed in our analysis. As shown, these benefits compare to $200 million in estimated IESO implementation costs. Modest additional implementation costs will also be incurred by market participants (not shown in the figure).

Overall, we estimate the 10-year present value of Market Reform benefits at approximately $3.4 billion (net of implementation costs), with a baseline benefit-to-cost ratio of 18-to-1. Considering the uncertainties in the nature of reforms and the magnitude of benefits from each workstream, these net benefits over ten years could range from $2.2 billion to $5.2 billion, with a benefit-cost ratio ranging from 12-to-1 to 27-to-1. In other words, the benefits from Market Renewal are expected to greatly outweigh the implementation costs, even considering the significant uncertainty range.

In addition to the quantified benefits included above, we expect Market Renewal to produce additional benefits that we have not yet quantified. For example, the above estimates do not include benefits of better integration

Figure 1 - Present Value of Market Renewal Benefits and Costs (2021–2030)



Notes: Results represent province-wide benefits from efficiency gains net of IESO implementation costs; they exclude any transfers payments among market participants.

of diverse and emerging resources, they do not capture the benefits of reduced opportunities for gaming and administrative burden for both the IESO and market participants, and do not include the longer-term savings from enabling innovation through a more open, competitive marketplace.

The overall benefits will be shared by customers and suppliers. Customers will pay less for electricity and the most competitive suppliers will benefit from increased opportunities to sell flexibility services, by generating energy where and when it is most valuable, and through improved opportunities to export energy and capacity. Investors of new resources and technologies will benefit from opportunities created by the anticipated types of reforms for Ontario. On the other hand, resources that do not contribute toward the flexibility needs of the system, those that have high net going-forward costs, or those that are currently receiving significant "above-market" compensation will likely see a reduction in total revenues as they will be exposed to greater competitive forces.

Recommendations

Based on the significant net benefits to the province, the IESO and stakeholders have decided to proceed toward the design stage of the Market Renewal. To maximize the benefits and mitigate the potential risks associated with Market Renewal, we recommend that the IESO and stakeholders carefully examine the available design choices and take advantage of experiences from other markets before selecting features that are most beneficial and consistent with Ontario's unique fundamentals and policy environment. We provide more specific recommendations for each workstream in the Findings and Recommendations section of our April 20th report. ■

DO MANUFACTURING FIRMS RELOCATE IN RESPONSE TO RISING ELECTRIC RATES?

Ahmad Faruqui and Sanem Sergici[1]

I. Introduction

Any time a manufacturing firm faces rising electric rates, it will evaluate the benefits of relocating to lower cost regions. However, since electricity costs for most firms are a small share of their total costs of doing business, relocation driven by rising electric rates is unlikely to make economic sense. Of course, a firm whose electric costs are a substantial portion of total costs, such as a primary smelter of aluminum, may well find it economic to relocate.

Arguably, if industrial customers relocated every time that their electric rates rose, there would be very few manufacturing firms left in regions with higher electric costs.

We investigate this issue by reviewing the variation in industrial rates across the US using a combination of primary and secondary data.

We find industrial rates vary considerably across the US and that manufacturing firms do not relocate in response to rising electric rates. We expect similar conclusions would flow from a review of Canadian data.

Our methodology is based on an approach which synthesizes information from two sources. First is a primary survey of customers based on email and phone interviews. The second is published information from secondary sources such as the Edison Electric Institute (EEI) and the Federal Energy Regulatory Commission (FERC).

We begin by displaying the variation in industrial rates across utilities in the U.S. We focus on customers with peak demands that range from 1 MW to 50 MW. Next, we identify the types of rates being offered to industrial customers by utilities. We also determine if any special rates are being offered to large industrial customers whose size exceeds 30 MW of demand. We conclude by making some observations on future trends in industrial rates.

Across 116 US utilities, we find that the average all-in industrial rate is 8.31 cents/kWh. The distribution is shown in **Figure 1** on the following page. The lowest rate is under 5 cents/kWh and the highest rate is around 35 cents/kWh. This wide dispersion does not support the proposition made by industrial customers that if electric rates go up, they would relocate to lower cost states. If that was literally true, no industrial customers would be found operating in higher cost areas.[2] All would move to lower cost areas.

Clearly, a number of factors are involved in industrial location decisions, including cost of doing business and access of markets. And cost of doing business includes labor costs, material costs, and taxes, in addition to electricity and other energy costs.

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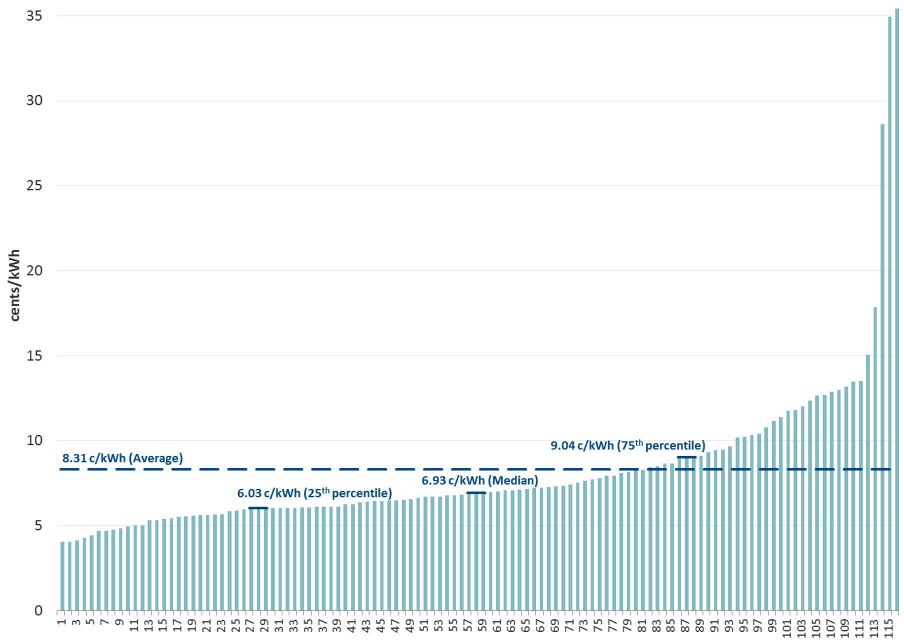
1 The authors are principals with The Brattle Group, located in San Francisco, California and Cambridge, Massachusetts, respectively. The views in this paper are those of the authors and not of their employer. Comments can be directed to ahmad.faruqui@brattle.com.

2 It could be argued that industrial customers at one time were all located in low electric rate areas. But this is unlikely to be true. There always has been considerable variation in industrial rates over time. And industrial customers have tended to locate throughout the US as opposed to just locating in regions with low electric costs.

Figure 2 presents a close-up of industrial rates by region. This figure might suggest that the south has the keenest competition for industrial customers, as shown by the tightly clustered industrial rate offerings by state. Other regions show a larger variation of industrial rates, perhaps suggestive of more captive industrial customers.

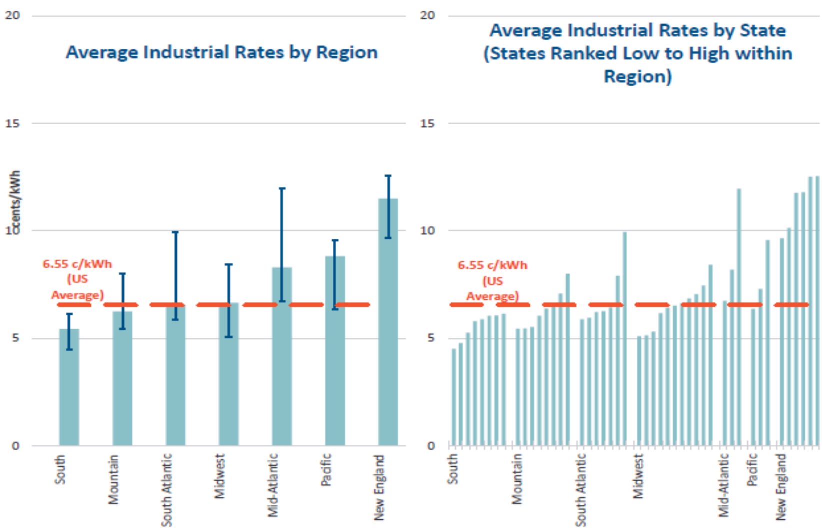
Another dimension we looked at is the distribution of rates by restructuring status of the States. We have seen that on average full retail access states have higher rates across all rate classes. Partially restructured states have rates comparable to those fully restructured. States that have abandoned restructuring have

Figure 1: Distribution of Average All-in Industrial Rates



Sources and Notes: The chart reports rates for 116 U.S. utilities from the EEI Summer 2013 Rates Report for the period from July 2012-June 2013. Rates for delivery-only companies are not included. For investor-owned utilities (IOUs) with service territories across multiple states, the weighted average rate across the states is reported.

Figure 2: Industrial Rates Close-Up by Region



rates comparable to non-restructured states.

Another important determinant of the rates is the fuel mix of the region. Regions with low cost fuel options (i.e., coal, nuclear) generally have lower rates compared to regions with more expensive fuel options (i.e., natural gas). The South Atlantic, Mountain, Midwest and Mid-Atlantic regions have a higher share of coal and nuclear generation mix and have lower rates. New England has the highest share of natural gas generation and the highest rates. The Pacific region is less fossil fuel intensive than New England and generally has lower rates compared to New England.

Figure 3: Average Electricity Rates across States with Different Regulatory Structures

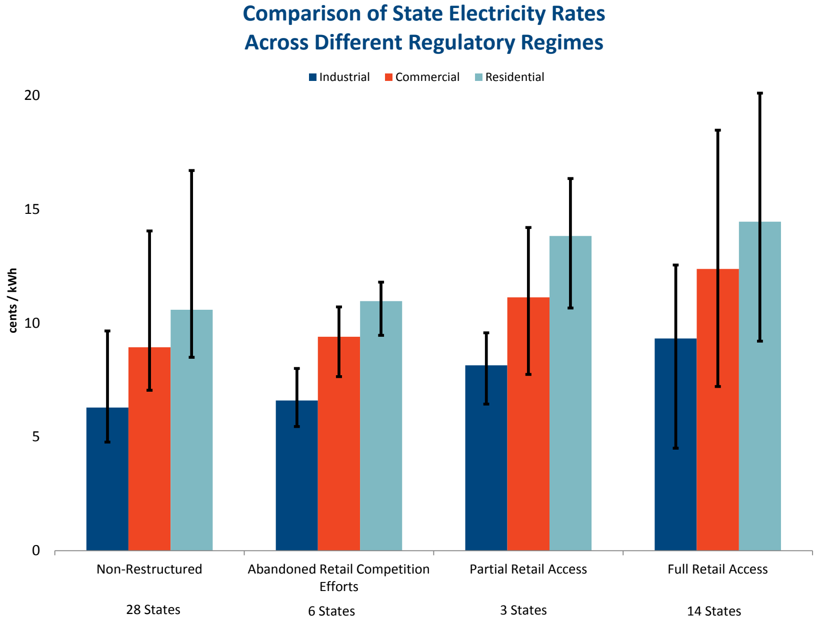
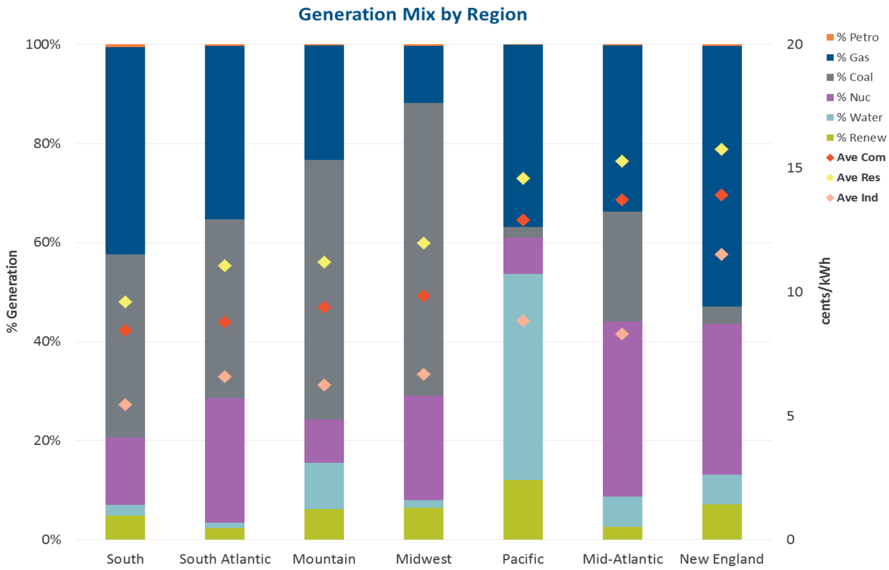


Figure 4: Generation Mix by Region



Source: EIA 2012 Historical Tables for Generation; 2013 EEI Annual Rates Report

II. Surveyed Utilities

To dig deeper into the issue, we reached out to 38 utilities to carry out telephone interviews. We were able to connect with 19 utilities, located in the Western, Midwestern, and Southern regions of the US. **Figure 5** represents geographical distribution of these utilities.

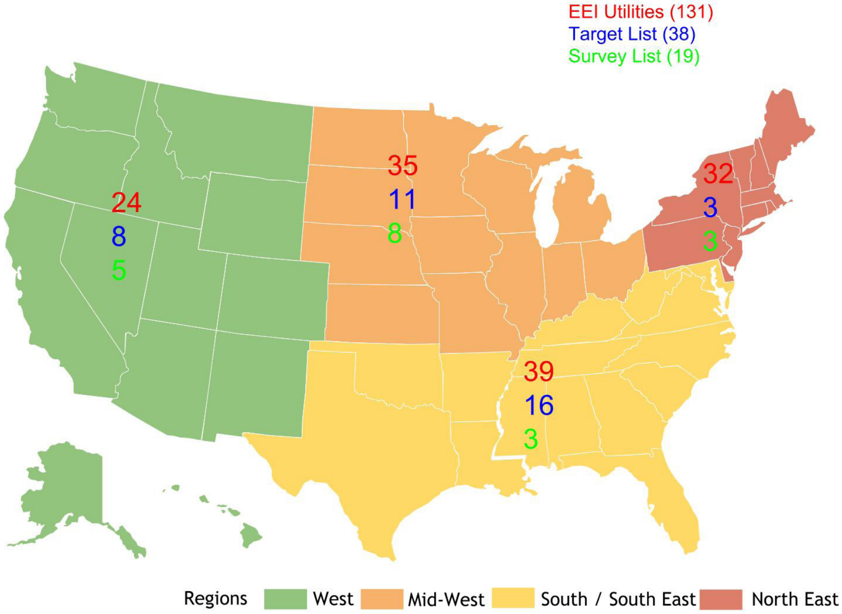
The average industrial customer size is 6 MW across the survey respondents and the average industrial class load factor is 63 per cent across the survey respondents.

See table 1 below.

Table 1: Summary Features of the Survey Respondents

Attribute	Description
Peak Load	2,000 MW to 22,000 MW
Annual Generation	11,000 GWh to 145,000 GWh
Fuel Mix	Mostly coal dominant or diverse mix
Customer Mix	Manufacturing, metals, agriculture, data centers
Has Generation?	14 own generation; 5 are delivery only
Restructured?	Majority of companies are based in non-restructured regions
Renewables?	Most have RPS requirements of 10-15 per cent in the next few years

Figure 5: Geographical Distribution of the EEI utilities, Target List, and Survey List

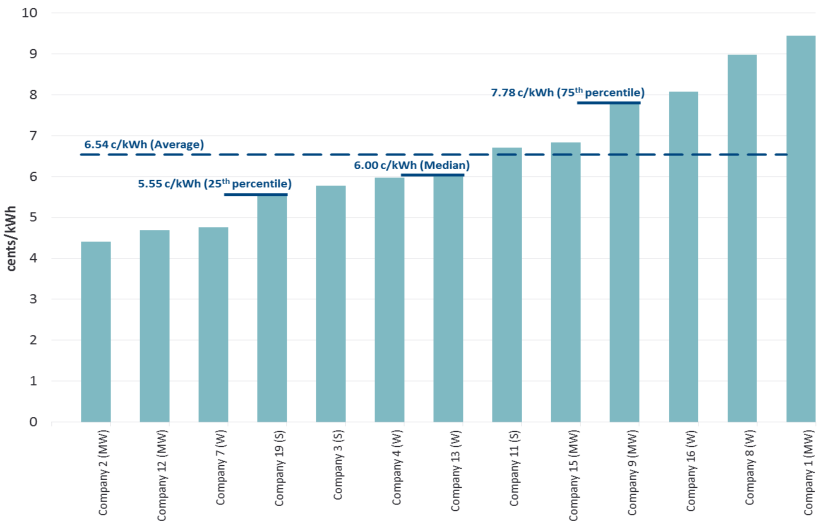


The "**EEI Utilities**" represents the vast majority of investor owned utilities across the US.
The "**Target List**" covers all major regions in the US.
The "**Survey List**" is a subset of the target list that we successfully interviewed.

Figure 6 shows the variation in rates across 13 of the 19 survey respondents. *The average all-in rate is 6.54 cents/kWh but there is considerable variation across the respondents, with the lowest rate being under 5 cents/kWh and the highest rate being around 9 cents/kWh.* The two-fold variation in prices in Figure 6 is less than the five-fold variation show in Figure 2, which included several outliers, but it is still substantial.

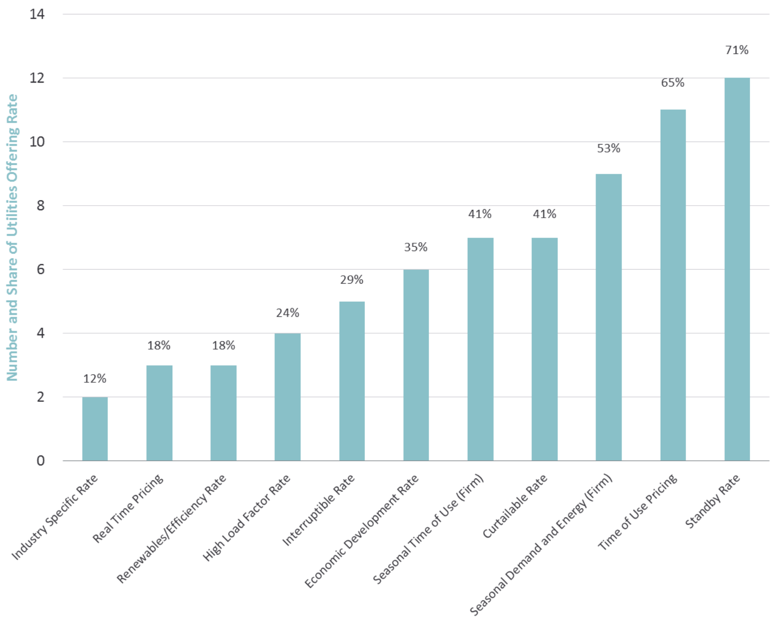
Several rate types are offered by the survey respondents to their industrial customers. The rate types and the percent of utilities in the sample offering them are shown in **Figure 7**.

Figure 6: Distribution of Average All-in Industrial Rates for Survey Respondents



Sources and Notes: Chart reports rates for 13 surveyed utility companies of the total 19 total surveyed companies. Rates for surveyed delivery-only companies not included in the chart. Rates from the EEI Summer 2013 Rates Report for the period from July 2012-June 2013.

Figure 7: Rate Types Offered by Survey Respondents



Special rates for large customers are offered by only 12 per cent of survey respondents, but they are not as popular as they used to be when "economic development" rates were commonplace. Most companies reported that they do not offer **negotiated** rates. Companies in restructured regions are not allowed to have special negotiated rates; companies reported having special contracts before restructuring. A few survey respondents offer **custom tariff rates** to a very small number of large customers (typically > 20 MW). Some companies based the custom tariffs on a cost of service methodology. A couple of survey respondents mentioned having custom rates for large industrial customer such as 450 MW smelting customer and a chemical company. Several surveyed utilities offer **industry-specific rates**, such as for automobile manufacturers or metal smelting plants or have recently launched **economic development rates** to attract small/ medium sized customers.

Real time pricing is offered by 18 per cent of respondents. The most popular rates are standby rates, 71 per cent, time-of-use pricing, 65 per cent, and seasonal demand and energy rates, 53 per cent.

See figure 7 on previous page.

About 50 per cent of the surveyed utilities have customers who have installed combined heat and power systems or co-generation. Of the ones that did not have such customers, the main reason given was that they had low electric rates. Of the ones who had high electric rates, a common reason that was cited was the presence of Renewable Performance Standards (more than 50 per cent of customers reported having RPS requirements).

We also asked survey respondents about historical and future trends in rates. Roughly a third of the respondents had seen rate increase in the past few years. Another third reported that rates had been stable. The last third stated that rates had changed slightly but did not disclose the direction of the change.

Looking at the future, 70 per cent of the respondents said they expected rates to rise in the next few years. The following reasons were provided: rising fuel costs, new generation coming online, changes in rate setting methodology, and the cost of complying with stringent environmental standards.

III. Conclusions

Industrial rates vary widely across the US for a variety of reasons including the fuel mix of the utility, its load shape, the cost of capacity and the cost of public purpose and environmental compliance programs. Despite the presence of higher rates in some regions and lower rates in other regions, industrial customers of different sizes and different industries are to be found in most states. Industrial relocation clearly is not just driven by the price of electricity. Many factors go into the relocation decision, including the other costs of doing business including labor costs and taxes, access to raw materials and access to markets.

Another interesting finding is that special rates for large customers are offered by only a small percentage of survey respondents and they are not as popular as they used to be when "economic development" rates were commonplace. Most utilities reported that they do not offer negotiated rates while a few utilities offer industry-specific rates, such as for automobile manufacturers or metal smelting plants. The most popular rates offered by the surveyed utilities are standby rates, time-of-use pricing, and seasonal demand and energy rates. ■

PROPOSED OIL TANKER MORATORIUM ACT – A BRIEF LOOK AT THE HISTORY OF THE MORATORIUM

*David Bursey and Charlotte Teal**

On 12 May 2017, the Government of Canada introduced Bill C-48, the proposed *Oil Tanker Moratorium Act*[1], in Parliament. This initiative follows up on the launch of the national Oceans Protection Plan in November 2016 and fulfils the Prime Minister's commitment to formalize a crude oil tanker moratorium on British Columbia's north coast. The broader plan aims to "improve marine safety and responsible shipping; protect Canada's marine environment; and create new partnerships with Indigenous and coastal communities".[2]

When the federal government talks about "formalizing" a crude oil tanker moratorium, it is helpful to review the historical background and the restrictions on oil tanker traffic that exist today – informal or otherwise. The status or need for an oil tanker moratorium on the West Coast has been a high profile topic in British Columbia for decades. This article reviews some of that contentious history to assist in understanding where we have been and where we may be heading.

1. A few facts about oil activity and tankers on the British Columbia coast

Oil tankers have been travelling along the British Columbia coast since the 1930s. Transport Canada reports that, in 2015, there were about 197,513 departures and arrivals of vessels at British Columbia ports, with tankers accounting for about 1487 – about 0.75 per cent.[3]

Oil is shipped mostly through the ports in Vancouver, Prince Rupert, and Kitimat, and most shipments are to and from communities along the coast. Oil is carried by barges, container ships, ferries, and other types of commercial and private vessels.[4]

The first oil wells were drilled between 1913 to 1915 in the Queen Charlotte Basin at Tian Bay, on the west coast of Graham Island.[5]

2. How the proposed moratorium works

The proposed moratorium is designed to complement the existing Voluntary Tanker Exclusion Zone, which has been in place since 1985.[6]

The basic features of the proposed legislation are:

- Oil tankers carrying over 12,500 metric

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1 Bill C-48, *An Act respecting the regulation of vessels that transport crude oil or persistent oil to or from ports or marine installations located along British Columbia's north coast,* 1st Sess, 42nd Parl, 2017.
2 Transport Canada, Press Release, "Government of Canada introduces *Oil Tanker Moratorium Act*" (12 May 2017).
3 Transport Canada, "Get the facts on oil tanker safety in Canada" (15 May 2017), online: <http://www.tc.gc.ca/eng/marinesafety/facts-oil-tanker-safety-canada-4513.html#west-coast>.
4 *Ibid*.
5 Ministry of Energy, Mines and Petroleum Resources, "Offshore Oil & Gas in BC: A Chronology of Activity", online: <http://www.empr.gov.bc.ca/Mining/Geoscience/MapPlace/thematicmaps/OffshoreMapGallery/Pages/chronologyofactivity.aspx>.
6 *Supra* note 2.

tons of crude or persistent oils as cargo are prohibited from stopping, loading or unloading these oils at ports or marine installations in northern British Columbia.

- The proposed tanker moratorium applies to the northern coast of British Columbia from the northern tip of Vancouver Island to the Alaska border – specifically, north of 50°53'00" north latitude and west of 126°38'36" west longitude.
- Vessels carrying less than 12,500 metric tons of crude or persistent oil as cargo will continue to be permitted in the moratorium area so northern communities can receive shipments of heating oils and other products.
- The master of an oil tanker that can carry over 12 500 metric tons of oil in bulk in liquid form must file a pre-arrival report with the Minister of Transport before entering the moratorium area.
- The definition of crude oil mirrors the definition in the *International Convention for the Prevention of Pollution from Ships.*
- Persistent oils are listed in a schedule to the Act and include heavier products that are slow to dissipate, including: partially upgraded bitumen, synthetic crude oil, petroleum pitch, slack wax, and bunker C fuel oil.
- Refined petroleum products may be removed from or added to the list, based on science and environmental safety criteria.
- The Minister may exempt an oil tanker from the prohibition if it is "essential for the purpose of community or industry resupply or is otherwise in the public interest".
- The remedies and penalties for contravention may include a fine up to $5 million, imprisonment, detention and sale of the vessel. Owners, directors and officers may be parties to an offence.

3. Current Federal Restrictions on Offshore Oil-related Activities

Two types of offshore oil-related activities that have been the focus of federal and provincial government attention and discussions related to moratoria: 1) oil and gas exploration, and 2) crude oil tanker traffic.

The federal government has through policy and executive order, imposed a *de facto* moratorium on oil and gas exploration off the British Columbia coast since 1972.

In 1972, the federal government also announced a moratorium on crude oil tanker traffic through the Dixon Entrance, Hecate Strait, and Queen Charlotte Sound, but it never implemented the moratorium through legislative instrument. The status of the moratorium has been a source of debate and confusion ever since. In law and in practice, the federal government allows and regulates the export, import or the shipment of oil to or from British Columbia ports.

The federal government has through agreement with the United States established a Voluntary Tanker Exclusion Zone that restricts the transit of oil tankers from Alaska to Washington, but that restriction is specific and narrow.

Further explanation follows.

a. Moratorium on oil and gas exploration, 1972

In 1972, the federal government announced a moratorium on oil and gas exploration off the British Columbia coast. It implemented the moratorium through policy by deciding to stop issuing any further exploration permits for the British Columbia offshore and suspending work obligations on existing permits. This approach imposed a *de facto* moratorium on those parts of the offshore under federal jurisdiction.[7]

In 1989, British Columbia announced it would not permit offshore exploration for at least 5 years. The federal government reaffirmed its

[7] Lynne Myers & Jessica Finney, *Offshore Oil and Gas Development in British Columbia: Status of Provincial and Federal Moratoria*, 2004, Library of Parliament, Science and Technology Division, p 1. See also, Ministry of Energy, Mines and Petroleum Resources, Chronology, *supra* note 5.

policy and added that it would consider no offshore development until requested to do so by the B.C. government. [8]

The British Columbia initiated a review of its moratorium in 2002, and ended the provincial moratorium following that review. The Province then called for the federal government to review the federal moratorium, which led to a series of reviews and reports.[9]

b. Moratorium on Oil Tanker Traffic

There is some dispute over whether a federal moratorium on crude oil tanker traffic ever progressed past a policy announcement to reach effective status. Government reports, both federal and provincial, conflict on this point. However, no federal legislation establishes a federal moratorium and crude oil shipments are permissible and regulated in the normal course.

Several federal and provincial reports since 1972 refer to a moratorium on crude oil tanker traffic, for example:

- In a 1986 joint federal/provincial review of offshore exploration, the offshore moratoria were described as follows.

  > In 1972, the federal government imposed a moratorium to prevent crude oil tankers travelling through the Dixon Entrance, Hecate Strait and Queen Charlotte Sound enroute from the Trans-Alaska pipeline terminal at Valdez, Alaska. Subsequently, a federal Order-in-Council indefinitely relieved existing offshore exploration permit holders from their obligations to conduct exploratory drilling in these waters and prohibited any further drilling.
  >
  > In 1981, the Province of British Columbia reinforced the moratorium when it declared an Inland Marine Zone. At the same time, an indefinite moratorium was placed on offshore exploration in Johnstone Strait south of Telegraph Cove, in the Straits of Georgia and Juan de Fuca. As of February 1986, all of these respective moratoria are still in effect.[10]

- The terms of reference for the federal 2003 Public Review Panel[11] and the concurrent Science Review Panel[12] state:

  > In 1972, the Government of Canada imposed a moratorium on crude oil tanker traffic through Dixon Entrance, Hecate Strait, and Queen Charlotte Sound due to concerns over the potential environmental impacts. The moratorium was subsequently extended to include oil and gas activities. This was followed by a similar prohibition by the Government of British Columbia.

- The terms of reference for a British Columbia 2002 scientific review panel describe the provincial perspective as follows:[13]

  > British Columbia has restricted offshore oil and gas activity since 1959, with the exception of a brief period from 1965 to 1966. The Province has issued three separate orders in council (1959, 1966 and 1981), reserving the seabed floor off the Queen Charlotte Islands and Vancouver Island to the Provincial Crown.
  >
  > A federal moratorium has also been in place since 1972.

8 *Ibid.*
9 *Ibid.*
10 *Report and Recommendation of the West Coast Offshore Exploration Review Panel* 1986, Joint Review, Canada and British Columbia, p 9.
11 Public Review Panel, *Report of the Public Review on the Government of Canada Moratorium on Oil and Gas Activities in the Queen Charlotte Region of British Columbia* (Ottawa: 29 October 2004). This report was commissioned by the federal government following a request for review from the BC government.
12 The Royal Society of Canada, *Report of the Expert Panel on Science Issues Related to Oil and Gas Activities, Offshore British Columbia* (Ottawa: February 2004).
13 Scientific Review Panel, *British Columbia Offshore Hydrocarbon Development – Report of the Scientific Review Panel* (15 January 2002).

a) Voluntary Tanker Exclusion Zone, 1985

Following the completion of the Trans Alaska pipeline system in the 1970s, tankers transported crude oil from Alaska to ports along the West Coast of the United States. Routes were established in 1977 to respond to environmental risks. Those routes required the tankers to travel far to the west of the Queen Charlotte Islands and Vancouver Island.

Between 1982 and 1985, those routes were disputed because of the added cost. Canada and the United States studied the routes and risks, and settled on agreed routes.

In 1985, the federal government negotiated the Voluntary Tanker Exclusion Zone (TEZ) with the United States Coast Guard. The TEZ extends from the shores of British Columbia westward and was calculated based on the worst possible drift of a disabled tanker with a cargo versus the time required for help to arrive. Loaded oil tankers travelling from Alaska to Washington must travel west of the zone.[14]

Following discussions in 1988 involving the United States and Canadian Coast Guards and representatives from the United States Tanker industry user group, all agreed that the TEZ would be voluntarily adopted along the British Columbia coast. [15]

The TEZ does not apply to tankers travelling to or from Canadian ports.[16]

4. The new moratorium on oil tankers on the northern coast – where are we heading?

In November 2015, the Prime Minister directed four federal ministers to work together to "formalize a moratorium on crude oil tanker traffic on British Columbia's North Coast" (the "Proposed Moratorium").[17] The idea of a moratorium is not new, but the restriction in the proposed Act is. If enacted, the Act will resolve any confusion about the status of an oil tanker moratorium.

Prime Minister Trudeau said recently, "No country would find 173 billion barrels of oil in the ground and just leave them there".[18] While that statement demonstrates the federal government's commitment to developing Canada's oil resources, the Act creates a substantial logistical hurdle for that development.

The proposed Act defines a clear policy choice about where crude oil can be exported on the British Columbia coast – i.e. export only from the South Coast. That choice has profound implications for British Columbia and Canada economies, which both depend heavily on the export trade.

Restricting the options for export will add cost and complication to developing our oil resources. Is that cost worth the benefit relative to the risk? Are there other options to protect the northern coast? The analysis supporting the policy choice merits close examination to determine the best approach to serve Canada's environmental and economic interests.

As this proposed Act proceeds through Parliament, we will undoubtedly hear more on this long-standing debate. ■

14 Transport Canada, "Safe routing and reporting for vessels" (15 May 2017), online: <http://www.tc.gc.ca/eng/marinesafety/safe-routing-reporting-vessels-4516.html>.

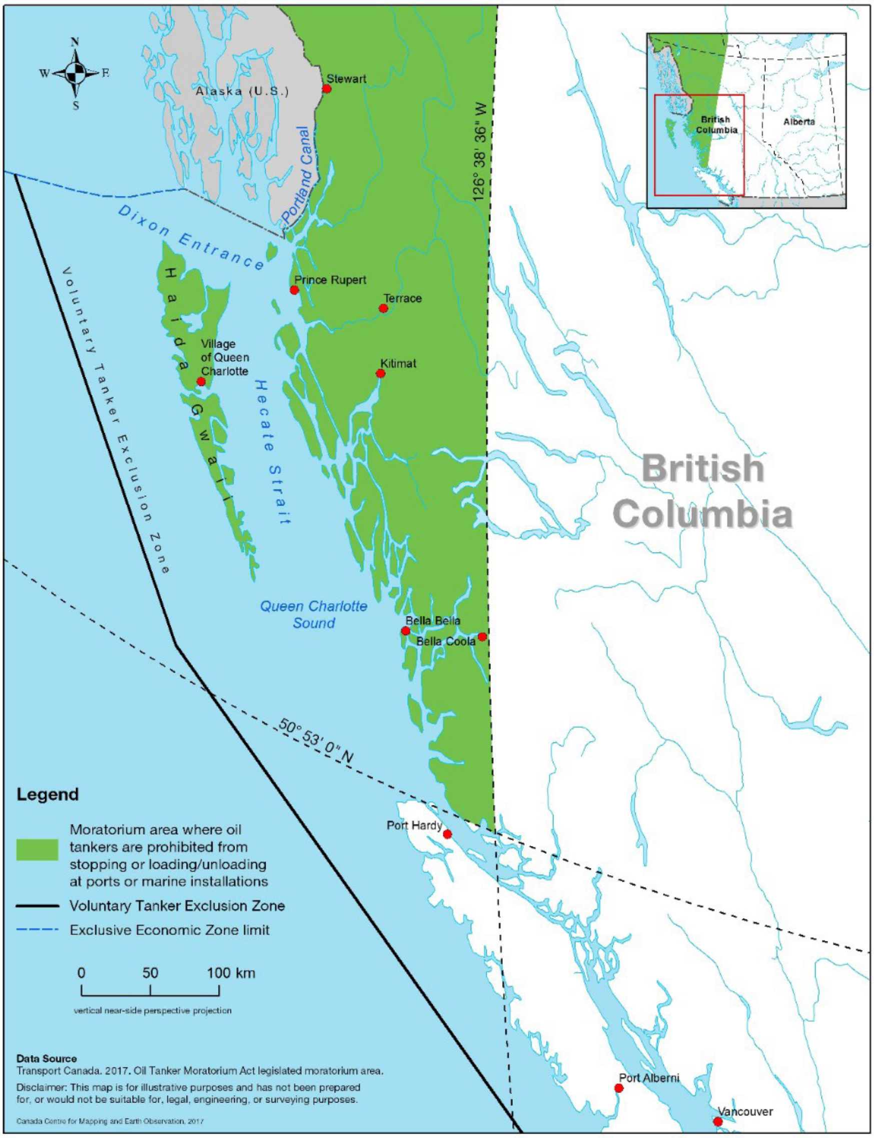
15 Canadian Coast Guard, "Information on the Voluntary Tanker Exclusion Zone", online: <http://www.ccg-gcc.gc.ca/e0003909>.

16 *Supra* note 14.

17 Office of the Prime Minister, "Letter to the Minister of Fisheries" (Ottawa: November 2015), online: <http:/pm.gc.ca/eng/minister-fisheries-oceans-and-canadian-coast-guard-mandate-letter>.

18 "Trudeau: No country would find 173 billion barrels of oil in the ground and leave them there" *CBC News* (10 March 2017), online: <http://www.cbc.ca/news/world/trudeau-no-country-would-find-173-billion-barrels-of-oil-in-the-ground-and-leave-them-there-1.4019321>.

The Proposed Moratorium Area



‘CAP AND TRADE’ AND PRICE TRANSPARENCY: A COMMENT ON THE OEB’S DECISION IN EB-2015-0363

*Moin A. Yahya**

Background

The recent Ontario Energy Board (OEB) decision regarding displaying the cost of ‘cap and trade’ on customers’ bills has ruffled a few feathers.[1] In a decision relating to how bills that contain the new ‘cap and trade’ charges should be presented to consumers, the OEB decided in a report that such charges should not be presented in a separate line item.[2] Rather, the OEB ordered the ‘cap and trade’ charges be merged into the delivery charges line item. This comment will review and provide some critical assessment the OEB’s decision.

Briefly speaking, a ‘cap and trade’ regime is one where the government sets emissions targets for various emitters. The emitters can either meet their targets by reducing their emissions or by purchasing emission allowances in a ‘cap and trade’ market. These allowances are sold by the government or by other emitters who have been able to reduce their emissions below their target. Under Ontario’s *Climate Change Mitigation and Low-carbon Economy Act*[3], natural gas distributors are required to meet certain emission targets most likely through the purchase of allowances.[4] When these distributors purchase these allowances, they then pass the cost of purchasing the allowances onto the customers. Among many questions related to design of the ‘cap and trade’ regime, was the question of bill presentment, or what will the final customer bill look like? Very relevant to this question was whether the charges would be a separate line item or whether they would be merged into the general delivery charges item. The OEB had issued a preliminary report inviting comments from all interested participants regarding various aspects of the regime, including the question of bill presentment.[5]

The OEB received almost forty comments.[6] Almost all of them addressed the question

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1 No one story captures the response to the OEB’s decision, but one can get the sense of it from stories such as “Kathleen Wynne says she is being transparent about cap-and-trade costs” *CBC News* (7 December 2016), online: <http://www.cbc.ca/news/canada/toronto/wynne-cap-and-trade-1.3885571>. Additionally, a Google search of “ontario cap and trade transparent” yields numerous results showing dissatisfaction with the OEB’s decision.

2 Ontario Energy Board, *Report of the Board regarding the Regulatory Framework for the Assessment of Costs of Natural Gas Utilities’ Cap and Trade Activities*, EB-2015-0363 (Toronto: OEB, 26 September 2016), at p 33, online: <https://www.oeb.ca/oeb/_Documents/EB-2015-0363/Report_Cap_and_Trade_Framework_20160926.pdf>.

3 *Climate Change Mitigation and Low-carbon Economy Act,* SO 2016, c 7.

4 *Supra* note 2 at 1, 3.

5 Ontario Energy Board, *Staff Discussion Paper on a Cap and Trade Regulatory Framework for the Natural Gas Utilities*, EB-2015-0363 (Toronto: OEB, 25 May 2016), online: <http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2015-0363/Cap_and_Trade_Staff_Discussion_Paper_20160525.pdf.>.

6 See list of comments on June 24, 2016, online: <https://www.oeb.ca/industry/policy-initiatives-and-consultations/consultation-develop-regulatory-framework-natural-gas>.

of bill presentment with the overwhelming (almost unanimous) majority arguing in favor of transparency in the bill presentment, i.e. that the 'cap and trade' charges be a separate line item.

The arguments in favor of making the charges a separate line item mostly revolved around the following three headings: 1) transparency, 2) impacting customer behavior by making them aware of how much it costs, and 3) customers' preference for a separate line item. The transparency argument came in various forms. Given that the 'cap and trade' charge is new, it is important for customers to see exactly why their bills would suddenly rise. Furthermore, some of the parties argued that the 'cap and trade' charges had nothing to do with the delivery of gas to the customers, and as such merging the charges into delivery charges was not accurate. The customer preference argument was advanced by Enbridge, which commissioned a study to ask residential customers about their views on the charges.[7] The study found that 86 per cent of the customers wanted to see a separate line item. Union Gas also conducted a similar study, with 92 per cent of those surveyed saying that it was important or very important to see a separate line item contain the charges.[8]

As to the customer impact, several commenters made the point that in order for the 'cap and trade' charges to achieve the true goal of the 'cap and trade' regime, namely reduction in emissions, it was important for customers to see what the regime was costing them. That way, individual customers could make their own decisions regarding their consumption of natural gas and alternative measures that would lead to lower emissions-related behavior such as the purchase of more energy-efficient appliances.[9]

On the other side, only the OEB and Environmental Defense argued that a separate line item was not needed due to concerns about customer confusion, although Environmental Defense seemed open to it being a separate line item if more information were presented on the bill. In response to the OEB's concerns that a separate line item may confuse customers, many comments highlighted the fact that there were already many charges in a bill, as well as the need for more proactive customer education.

At the conclusion of the process, the OEB decided not to require a separate line item, but rather have the charges merged with the delivery charges.

Comment

There are two main criticisms of the OEB's decision. One is grounded in political economy and the other in consumer behavior microeconomics. I will briefly address the political economy argument, but I will focus most my comments on the second point. The focus of this section is the assertion by the OEB in its final report that:

> For the vast majority of low volume customers, a separate line item will not provide any form of meaningful price signal. Customers other than voluntary participants cannot avoid the Cap and Trade program-related costs which will be borne by the Utilities and allocated to them. **The most important driver of consumer behaviour, in the OEB's view, is total price.** This has been borne out by research that the OEB has undertaken in the past in relation to consumers' response to electricity bills. This research showed that low volume customers are much more focused on the total amount owing on their bill than on individual line items.[10] (Emphasis added)

This assertion argues that if a customer is faced with a price $P^T=P^c+T$, that it does not

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7 Enbirdge Gas Distribution Inc, *Ontario Energy Board ("Board") – Consultation to Develop a Regulatory Framework for Natural Gas Distributors' Cap and Trade Compliance Plans EB-2015-0363 – Staff Discussion Paper, Comments of Enbridge Gas Distribution Inc* (22 June 2016), at p 15, online: <http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/532593/view/>.

8 Union Gas Limited, *EB-2015-0363 – Consultation to Develop a Regulatory Framework for Natural Gas Distributors' Cap and Trade Compliance Plans – Union Gas Limited Submission on Discussion Paper* (22 June 2016), p 14, online: <http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/532661/view/>.

9 See comments of IESO, SEC, LPMA, and Enbridge on June 24, 2016, online: <https://www.oeb.ca/industry/policy-initiatives-and-consultations/consultation-develop-regulatory-framework-natural-gas>.

10 *Supra* note 2 at 34.

matter whether the customer see the final price P^T or whether the customer sees the two components separately, namely the price of the commodity P^x plus a per unit charge T. At a basic level of analysis, this is correct. A simple microeconomic model of consumer behavior can prove this. But this model assumes that the only item that the customer is consuming is the commodity, which in this case is gas. I will return to this point in the second part of this section.

The other aspect of this assertion is the assumption that the 'cap and trade' charges are truly an emissions-controlling measure and not a disguised tax. It is with respect to this assumption, that the next section comes into play.

a. The Political Economy of Merged Charges

Milton Friedman is said to have regretted his role in designing the system of withholding income taxes, a system he blamed for the growth of government spending (and taxing).[11] Similarly, commenting on value added taxes, he observed that such taxes are invisible and hence it makes it easier to raise.[12] Indeed, he observed that every European country with value added taxes saw government spending rise sharply after they introduced the tax.[13] The idea of tax invisibility has been addressed by political economists, especially in the field of public choice.

Some political economists have referred to the idea of fiscal illusion and tax salience.[14] In a nutshell, these theories look at the lack of complete information available to taxpayers regarding various tax regimes such as the true costs of the taxes they pay versus the true benefits they receive from government spending. This allows governments over time to raise its taxes without facing much of a backlash from taxpayers. As such, while the 'cap and trade' charges are not taxes per se, they are charges not associated with the cost of producing the commodity being consumed in that the price is being set by a government agency. Hence, they have some features of taxes, and therefore can be susceptible to the same government temptations to raise revenues using the charges as an excuse.[15]

While these theories have some empirical support, they do require a more sophisticated analysis of how government fiscal policy interacts with energy policies, something that is beyond the scope of this short commentary. I simply raise this point to highlight one objection to merging the 'cap and trade' charges into general delivery charges. I do not necessarily ascribe these theories as the reason for the OEB's decision. Indeed, such theories do not operate on any intentional design by politicians, but rather they point out the unintended consequences of these invisible tax regimes.

b. Consumer Behavior

Returning to the OEB's assertion that customers only look at the final price, as I mentioned earlier, that assertion is correct if customers are only interested in the one commodity, namely natural gas. If, however, what consumers, or at least a subset of them, are interested in is not just natural gas, but also emissions by their gas supplier, the analysis is more complicated. Economists typically model customer behavior as follows: If a customer, whose income is I, is interested in consuming commodity x (say natural gas) and all other goods y, then customer behavior can be modelled by solving the following:

$$\max_{x,y} U(x,y) \text{ subject to } P^x x + y \leq I,$$

where U is the utility derived from consuming x and y, P^x is the price of x, and the price of y is normalized to 1. The result will be a demand

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11 David Gamage & Darien Shanske, "Three Essays on Tax Salience: Market Salience and Political Salience" (2011) Tax L Rev 65 at 19, 41.

12 *Ibid* at 21, n 11.

13 *Ibid*.

14 See e.g. Werner W. Pommerehne & Friedrich Schneider, "Fiscal Illusion, Political Institutions, and Local Public Spending" (1978) 31:3 Kyklos 381; Brian Dollery and Andrew Worthington, "The Empirical Analysis of Fiscal Illusion" (1996) 10:3 J. Economic Surveys 261; Gamage & Shanske, *supra* note 11.

15 Already the revenues expected from the 'cap and trade' have not been what the Ontario government expected. See "Ontario is expecting smaller cap-and-trade revenues in 2017 and 2018 than originally planned" *Canadian Press* (1 May 2017), online: <http://business.financialpost.com/news/economy/ontario-is-expecting-smaller-cap-and-trade-revenues-in-2017-and-2018-than-originally-planned>.

function of x that will depend on P^x and I. If the new 'cap and trade' regime results in a per unit charge of T that is added to P^x, then the new objective function to be optimized is as follows:

$$\max_{x,y} U(x,y) \text{ subject to } (P^x + T)x + y \leq I.$$

The reader can see that indeed, all that matters is the sum of the prices, as the resulting demand function will now depend on $(P^x + T)$ and I.

Suppose that customers also care about the amount of emissions that they are causing, including those caused by their gas supplier.[16] Now the utility of the customer comes from consuming x, em, and y, where em is the amount of emissions the customer is responsible for. For simplicity, I will assume the emissions are all related to consumption of x. Now the customers' behavior will be derived from:

$$\max_{x,em,y} U(x,em,y) \text{ subject to } P^x x + P^{em} em + y \leq I,$$

where P^{em} is the price of emissions that the customer pays.[17] Notice that if the amount of emissions are linearly related to the amount of gas consumed, then the OEB's assertion is correct.[18] But if the amount of emissions are not linearly related to the amount of gas consumed, then one cannot state with generality that all that matters is the combined price. The resulting demand function will be expressed as a function of P^x, P^{em} and I. This means that the customer needs to know both P^x (the price of the natural gas) and P^{em} (the price of the emissions) to properly make their utility-maximizing decisions. If what the customers sees is simply the sum of those two prices and can't distinguish their individual impacts, any decision they make most likely will be sub-optimal.

To understand whether customers only value the consumption of gas (or any other fuel) or also the reduction in emissions, one must look to the empirical evidence. There is an existing literature regarding the impact of tax saliency on customer behavior. For example, three economists found that posting tax inclusive prices in supermarkets reduced demand compared when only pre-tax prices were posted and the tax was simply added on at the register.[19] Similarly, another economist found that when drivers paid road tolls each time they drove on such roads, the introduction of electronic payment systems (which allow the driver to drive through and be billed automatically thereby not forcing the driver to face the toll price) meant that drivers were less concerned about the tolls. This allowed toll prices to rise 20 to 40 per cent above toll roads where no electronic payment options were present.[20] These results are inconclusive when it comes to whether the OEB was correct or not. This is because these studies deal with taxes where the only goal of the tax is revenue.

When it comes to pollution or emissions control, there is one very relevant study. Nicolas Rivers and Brandon Schaufele, two Canadian economists, examined the impact of British Columbia's (BC) carbon taxes on the gasoline consumption.[21] In BC, carbon taxes are displayed at the gasoline pump. This means that customers can see the amount of tax they are paying as they pump their gas. If indeed, all that customers cared about was the combined price, then whether the price of gasoline increased by \$0.05 or whether the carbon tax increased by \$0.05 should not matter for the impact on gasoline consumption. Yet, the study reports that consumers exhibited a greater response to an increase in the price of emissions than to an equally sized increase in the price of the commodity being purchased;

> A five cent increase in the market price of gasoline yields a 2.1 per cent reduction in the number of litres of gasoline consumed in the short-run, while a five cent increase in the carbon tax, a level approximately equal to a carbon price of \$25 per tonne, generates a 8.4 per cent short-run reduction in gasoline demand. These results lead us to claim that

16 Even if only a subset of customers care about emissions, the results qualitatively are the same.
17 This can be in the form of a carbon tax, 'cap and trade' charge, or any other cost associated with reducing emissions.
18 If $em = ax$, where a is a constant, then the effective price facing the customer is $P^x + aP^{em}$.
19 Raj Chetty, Adam Looney & Kory Kroft, "Salience and Taxation: Theory and Evidence" (2009) 99:4 Am Econ Rev 1145.
20 Amy Finkelstein, "E-ZTax: Tax Salience and Tax Rates" (2009), 124:3 Quarterly J Econ 969.
21 Nicolas Rivers & Brandon Schaufele, "Salience of Carbon Taxes in the Gasoline Market" (2015) 74 J Environmental Econ & Mgmt 23.

> the carbon tax is more salient than market-determined price changes: carbon taxes produce larger demand responses than tax-exclusive price increases.[22]

The authors offer several explanations for their results, some having to do with the specifics of BC's tax regime, while others having to do with customer preferences and views on emissions and taxes. What matters, however, is that the study demonstrates that customers are quite able to process various pieces of information when presented to them and that the final price is not all that matters.

While this is the only Canadian study that I could find on point,[23] other studies of tax salience (some I mentioned above) demonstrate that, at the very least, more of these studies are needed. Simply asserting that all that matters is the final price is simply not empirically true.

Conclusion

The OEB missed a valuable opportunity to contribute to the science surrounding customer behavior with respect to emissions. Had the OEB allowed the 'cap and trade' charges to be a separate line item, there have been an opportunity to test the salience of the charges with respect to customer behavior. This would have provided valuable information for future design of these charges and other environmentally related regimes. Additionally, if the results of the Rivers and Schaufele apply equally to Ontario, the OEB could have achieved even more emissions reductions by itemizing the costs of 'cap and trade'.

Although the OEB asserted that its studies showed that only the final price mattered, it would have been helpful had they presented the details of that study in their Staff Report. This would have allowed the commenting parties a chance to examine the questions of saliency and customer preferences. While two of the gas utilities presented survey-evidence regarding their customers' desires to see the charges separated from delivery charges, the vast majority of the comments were also devoid of any empirical evidence. Indeed, most of them presented no economic arguments, theoretic or empirical, whatsoever.

The public in all provinces in future proceedings will be better served if more economic theory and evidence is marshalled to examine the subtleties of regime design. Given the presence of vast theoretical studies, and a growing body of empirical evidence, bringing these studies to such proceedings is not that onerous a task. Indeed, more work should be done by all parties, and for that matter academics, in order to have more meaningful discussion of these issues. ■

22 *Ibid* at p 24.
23 The article contains citations to many other American studies.

DYSFUNCTION: CANADA AFTER KEYSTONE XL, DENNIS MCCONAGHY, DUNDURN TORONTO, 2017

*Reviewed by Rowland J. Harrison, Q.C.**

The saga of the Keystone XL project's tortuous journey through the U.S. public review process is by now well known. Despite repeated findings by the U.S. Department of State's assessments that the project would result in "no substantive change in global GHG emissions [and] was unlikely to have a substantial impact on the rate of development in the [Canadian] oil sands"[1], in November 2015 President Barack Obama denied a permit for the project, stating that approval would have undercut America's role as "a global leader when it comes to taking serious action to fight climate change."[2] While Keystone XL has since been permitted by President Donald Trump, the lessons to be learned from its earlier rejection should not be overlooked in Canada, where other pipeline projects are equally as controversial – and particularly as the federal government considers the report of the Expert Panel on National Energy Board Modernization.[3] A vigorous debate is certain to continue.

Dennis McConaghy's *DYSFUNCTION: Canada after Keystone XL* should be embraced by all interested parties as an invaluable contribution to this debate.[4] This is a unique chronicle from 'inside the tent'. Prior to his retirement, McConaghy was a senior executive at TransCanada and was directly involved in conceiving and executing Keystone XL from the time of the project's early formation in the mid-2000s.

This involvement will no doubt lead opponents of Keystone XL to dismiss his conclusions as self-serving, but that would be a serious mistake. Much of the controversy surrounding the project (and, indeed, its rejection by President Obama) revolved around the extent to which it would contribute to greenhouse gas emissions and affect climate change. Climate change is also at the core of much of the opposition to other pipeline projects. McConaghy, however, is no climate change denier:

> "To be clear, I believe that greenhouse gas emissions from human activity increase the risk of climate change. It is a risk that must be dealt with."[5]

Indeed, he explicitly supports a carbon tax and argues that the fate of Keystone XL at President Obama's hands may well have been different if the government of Prime Minister Stephen Harper had not been so adamantly opposed to

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1 US, Department of State, *Draft Supplemental Environmental Impact Statement* (Washington DC: Department of State, March 2013).

2 Barack Obama, "Statement by the President on the Keystone XL Pipeline", The White House, Washington DC (6 November 2015).

3 The Panel's Report was to be submitted to the federal government on May 15, 2017, online: <http://www.neb-modernization.ca/participate>. The Report will be reviewed in a future edition of *Energy Regulation Quarterly*.

4 Dennis McConaghy, *Dysfunction: Canada after Keystone XL* (Toronto: Dundurn Press, 2017).

5 *Ibid* at p 11.

such a tax.

McConaghy's conclusion, therefore, warrants respectful consideration. Keystone XL's cancellation "was a solely symbolic act, without real consequence for seriously dealing with the risk of climate change."

McConaghy's frustration is palpable from his observation that the ultimate rejection of the project by President Obama (when he 'finally made a decision') meant that an "agonizing and disingenuous charade was over." This is not mere hyperbole – McConaghy records instances throughout the process when TransCanada was misled into thinking its agreement to additional conditions and environmental assessments would ultimately lead to approval. In retrospect, it became apparent that the U.S. administration was intent on delaying having to make a final decision, rather than upholding the integrity of the regulatory process. At the time of the final rejection of the project in November 2015, Secretary of State John Kerry stated that the decision "could not be made solely on the numbers."[6] McConaghy comments that this was doubtless a "truthful reflection" of the President's and the Secretary's mindset, leading him to conclude that "[d]ue process and technocratic assessment counted for nothing."

There are obvious differences between the regulatory review processes in the U.S. and Canada. McConaghy's account of the Keystone XL experience is nevertheless relevant here, where the politicization of energy projects continues to grow. In 2012, the role of the National Energy Board was fundamentally changed from that of decision-maker to advisory, with direct decision-making being transferred to the federal cabinet. The potential for politics to outweigh independent analysis was thereby increased significantly. The experience of the Keystone XL project graphically demonstrates the consequences of embarking on that path.

McConaghy's assessment is not encouraging:

> "The most disheartening thought that grips me in the aftermath of Keystone XL's lengthy demise is just how little Canada has learned…Proponents of major hydrocarbon infrastructure in this country endure a lengthy, potentially disingenuous decision process, with outcomes that may not relate to the actual regulatory assessment of benefits and mitigated environmental risk."[7]

Hopefully, debate and action on the report of the Expert Panel on National Energy Board Modernization will lead to improvements.

But perhaps the wider significance of *Dysfunction* lies behind the sub-title: *Canada after Keystone XL*. In Part Two, McConaghy reviews "Canada's Other Pipelines: Northern Gateway, TransMountain, and Energy East" against the background of the Keystone XL experience. His review leads him to pose this question:

> "Does Canada really share the fundamental conviction that developing its hydrocarbon resources is in their public interest? Since KXL's demise, Canada has shown itself profoundly equivocal to that proposition."[8]

Indeed, this is the question that is central to the controversial debate around these and future energy infrastructure projects in Canada.

Dysfunction is an important contribution to the debate. It should be read widely by politicians, policy-makers regulators, industry and concerned citizens. ■

6 John Kerry, Press Statement "Keystone XL Pipeline Permit Determination" (6 November 2015).
7 *Supra* note 4 at p 194.
8 *Ibid* at p 137.