ENERGY REGULATION QUARTERLY

VOLUME 3, ISSUE 2 2015

MISSION STATEMENT

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

TABLE OF CONTENTS

<u>EDITORIAL</u>

Editorial 9
Rowland J. Harrison, Q.C. and Gordon E. Kaiser, FCIArb

<u>ARTICLES</u>

The Past, Present and Future of Energy Conservation in Ontario 11
Peter Love

Conservation First: In Theory and Practice...17
Jack Gibbons

The Reform of the Renewable Energy Act in Germany...23
Ralf Thaeter and Silke Goldberg

Changing Views of the Role of Canadian Natural Gas in the United States............................29
André Plourde

Improving Ontario's Energy Infrastructure: Reducing the Cost of LDCs................................43
Duncan Melville, CFA

Utility Dealings with Freemen-on-the-Land and Others Raising "Organized Pseudo-Legal Commercial Arguments" 51
Jason K. Yamashita

<u>CASE COMMENTS</u>

Pipelines, the National Energy Board and the Federal Court...59
Nigel Bankes

EDITORIAL

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

Energy issues continue to play a central role in Canadian public discourse, shaped by the fluid interaction of evolving public expectations, technological developments, changing markets, public policy and politics. The articles in this issue of *Energy Regulation Quarterly* address particular aspects of these dynamics, including energy conservation, renewable energy, changes in the natural gas market between Canada and the U.S. and consolidation of electricity LDCs in Ontario with a view to realizing significant cost savings.

Peter Love's article on "The Past, Present and Future of Energy Conservation in Ontario" summarizes the key components of Ontario's past and present conservation efforts, then uses this background to suggest the most important developments needed in order for the full potential of conservation to be realized in Ontario.

Love's article is complemented by Jack Gibbons' article on "Conservation First: In Theory and Practice", which reviews the Conservation First policy announced by the Ontario government in December 2013 with respect to electricity and natural gas. Gibbons describes the policy as "both revolutionary and common sense," while arguing that the Ontario Energy Board is implementing policies that will frustrate the implementation of Conservation First with respect to both electricity and natural gas.

The drivers underlying evolving energy policies are not, of course, unique to North America. Ralf Theater and Silke Goldberg's article on "The Reform of the Renewable Energy Act in Germany" provides a valuable description of the approach to promoting renewable energy recently adopted in the European Union's largest economy. The German experience is frequently referenced in North America and is of particular interest when a number of Canadian electricity markets are pursuing significant change.

Significant changes in the structure of the North American gas market have resulted over the last few years from the widespread adoption of "fracking" technology to access extensive deposits of shale gas. André Plourde's article on "Changing Views of the Role of Canadian Natural Gas in the U.S." provides an empirical review of these changes. Plourde concludes that the changing role for Canadian natural gas in U.S. markets may create new market opportunities outside Canada and offers some observations on policy and regulatory issues that may arise.

Duncan Melville's article on "Improving Ontario's Energy Infrastructure: Reducing the Cost of LDCs" discusses the potential for restructuring in the Ontario electricity market. He concludes that "significant annual cost savings would be realized through consolidation of Ontario's smallest LDCs." He suggests that outright privatization should be resisted, in favor of tendering of LDC operations to private concessionaires, which would provide "a suitable solution to the roadblocks currently preventing consolidation." He recommends that the government ask the Ontario Energy Board to study the feasibility of creating regional distribution companies and tendering of their management to private sector operators.

While Jason Yamashita's article on "Utility Dealings with Freemen-on-the-Land and Others Raising 'Organized Pseudolegal Commercial Arguments'" is not directly concerned with energy regulation or policy issues, it addresses a real problem that is faced by some regulated utilities. Yamashita reviews an important Alberta Queen's Bench decision in which the Court labelled a certain group of "vexatious litigants" as "Organized Pseudolegal Commercial Argument" (or OPCA) litigants. He offers suggestions on how utilities might best deal with OPCA litigants to minimize the associated costs and risks.

In the Case Comments section of this issue of *ERQ*, Nigel Bankes reviews the numerous judicial challenges to review proceedings with respect to the Northern Gateway project, the proposed TransMountain expansion, the reversal and expansion of Enbridge Line 9 and the proposed Energy East project. In the past, with occasional exceptions such as the original proposal for the Mackenzie Valley pipeline in the 1970s, the regulatory review of proposed new energy infrastructure projects generally proceeded with relatively little controversy. For example, the Norman Wells and the Express oil pipelines and the Maritimes & Northeast and the Alliance natural gas pipelines were approved and constructed as greenfield projects between the mid-1980s and 2000 without the pervasive controversy that is being faced by current pipeline projects. There are approximately 15 judicial proceedings challenging the National Energy Board and the Governor in Council. Indeed, in April, the NEB took the unprecedented step of posting a table on its website to assist interested parties in keeping track.

These challenges raise fundamental issues, including the validity of the NEB's position that it will not consider climate change effects upstream and downstream of the pipeline projects over which it has jurisdiction. Other issues include restrictions on rights to participate in NEB proceedings that were introduced in 2012 and the constitutional paramountcy of the NEB's pipeline jurisdiction over the authority of local governments. The judicial resolution of each of these issues will be significant for projects currently before the NEB and for future energy infrastructure projects. ■

THE PAST, PRESENT AND FUTURE OF ENERGY CONSERVATION IN ONTARIO

*Peter Love**

This article summarizes the key components of Ontario's past and present activities in energy conservation. It then uses this background to identify some of the likely key elements and drivers of future activities. Before going further, it is useful to first define energy conservation and identify some of its distinctive challenges as well as its major benefits.

Different jurisdictions use various terms such as energy efficiency, energy conservation, demand response, demand side measurement (DSM), conservation and demand management (CDM). For the purposes of this article, energy conservation is the all-encompassing term that includes the following three main elements:

- **conservation behaviour** – using existing technology more efficiently (e.g. a light switch and programmable thermostat)
- **energy efficiency** – using more energy efficient technology (e.g. LED light bulbs and LEED buildings)
- **demand response** – using less energy at peak periods (e.g. using electrical appliances at off-peak periods or shedding industrial load at on-peak periods)

In comparison to the much higher profile associated with energy supply, conservation suffers from a few challenges. Most importantly, it is hard to see: it is in the walls and inside appliances. It is also harder to measure than energy supply, but can be done using widely accepted protocols. And it requires all sectors to participate. But the benefits to society are too important to ignore. As we currently waste approximately 68 per cent of the primary energy consumed,[1] the potential is huge. The environmental benefits of not using energy in the first place are obvious. Not so obvious are the economic and employment benefits. A recent study conducted for NRCan found that the most aggressive conservation scenario would result in an increase in GDP of $582 billion, add up to 350,000 people to the workforce, grow provincial tax revenues by $2.7 billion and cut CO_2 emissions by 92 MT/year over the next 15 years.[2]

Those who have tried to follow the evolution of electricity conservation in Ontario over the last ten years can be excused for being confused, as there have been four distinct initiatives:

- Ontario Energy Board (OEB) Third Tranche funding for Local Distribution Companies (LDCs)
- Ontario Power Authority (OPA) programs that were delivered by LDCs

* Peter Love is the Chief Energy Conservation Officer at Summerhill, a leader in energy efficiency program delivery. He is also an Adjunct Professor at the Faculty of Environmental Studies at York University. Ten years ago, in May 2005, the Province of Ontario appointed him Chief Energy Conservation Officer to promote energy conservation through leadership, programs and policy recommendations.

1 Sankey Diagram of Canada's Energy Systems, *Canada's Energy Systems in 2010,* online: Canadian Energy Systems Analysis Research (CESAR) <http://www.cesarnet.ca/visualization/sankey-diagrams-canadas-energy-systems?scope=Canada&year=2010&modifier=none&display=value&hide=all&scalevalue=0.014651030728638501>.

2 Leslie Malone et al, "Energy Efficiency: Engine of Economic Growth in Canada – A Microeconomic Modeling & Tax Revenue Impact Assessment" (March 2014), online: Acadia Center <http://acadiacenter.org/wp-content/uploads/2014/10/ENE_ExecSummary_EnergyEfficiencyEngineofEconomicGrowth_EasternCanada_EN_2012_0611_FINAL2.pdf>.

as well as other channel partners

- Ontario Ministry of Energy which drove the province-wide roll out of smart meters
- LDCs whose programs will be approved by the Independent Electricity System Operator (IESO who were merged with OPA) and whose targets will be monitored by the OEB

This article will put these and other initiatives into a historical context and will use the experience gained from them to identify key elements of future initiatives.

THE PAST

Although not documented, it would be safe to assume that before the use of fossil fuels, First Nations and early settlers did their best to conserve energy as they had to cut firewood, walk/paddle or feed animals to keep warm and move about. The adoption of s. 92A (1) of the *Constitution Act, 1867*, by way of the 1982 amendments specifically assigned the provinces with the jurisdiction to legislate on matters relating to non-renewable and forestry resources which includes conservation.[3] This is part of the reason why this article is focussed on Ontario. The World Wars brought increased attention to the need to conserve food, resources and energy with gasoline rationing introduced in April 1942; some Canadians decided to put their cars in storage for the duration of the war.[4]

In 1973, the federal Department of Energy, Mines and Resources (now Natural Resources Canada) created the Canadian Office of Energy Conservation that has offered various information and incentive programs since then, operating more recently as the Office of Energy Efficiency. Also that year [1973], the Science Council of Canada called on all Canadians to begin the transition to a "conserver society".[5] In Ontario, the Ministry of Energy began developing policies and programs in 1975.

In 1980, the Royal Commission on Electric Power Planning (known as the Porter Commission) recommended that future planning should be reoriented to emphasize demand management.

Ontario Hydro set a target of 1000 MW of load shifting and 1000 MW of conservation in 1982. In 1989 it included a budget of $3 billion in conservation programs as part of its Demand/ Supply Plan that was subsequently withdrawn. During this process, it began offering demand-side management programs that were able to reduce electricity consumption by 1,200 MW before it was discontinued in 1993;[6] this was also the time when the new Darlington nuclear plant began operating at a time when there was a surplus of capacity.

In 1990, the *Ontario Energy Efficiency Act* provided the province the ability to require minimum energy performance standards (MEPS) on the sale of specified energy consuming products. In 1992, the federal *Energy Efficiency Act* provided the federal government the ability to require MEPS on products traded across provincial or international boundaries. To date, about 80 products in Ontario have MEPS; updated requirements introduced in 2013 were estimated to result in savings of about 2 TWh by 2030.[7]

Ontario's first Building Code was introduced in 1975 and, like the *Energy Efficiency Act,* required new buildings (both low rise and high rise) and major renovations to meet minimum energy performance standards. Despite attempts to remove these provisions in the late 90s, they remained and are now among the highest in North America[8] and were estimated to save 550 MW when fully implemented.[9]

The Ontario Energy Board established the original regulatory framework that governed demand-side management programs by the two natural gas utilities in Ontario in 1993. Using California's example, the conservation programs

---

3 *Constitution Act, 1867* (UK), 30 &31 Vict, c 3, s 92A.
4 *WW2,* online: The Canadian Military Heritage Project <http://www.rootsweb.ancestry.com/~canmil/ww2/home/ration.htm>.
5 Science Council of Canada, "Natural Resource Policy Issues in Canada", (Ottawa: Science Council of Canada, 1973) at 39.
6 Rebecca Mallinson, "Electricity Conservation Policy in Ontario: Assessing a System in Progress", York university Faculty of Environmental Studies (Toronto: March 2013) at 148 [*Mallinson*].
7 Ontario, Office of the Premier, News Release, "Ontario Regulations Coming into Force on January 1 2013" (Toronto: 31 December 2012) at 8.
8 Canadian Energy Efficiency Alliance, Press Release, "New Energy Efficiency Code in Ontario – Best in North America!" online: CEEA <http://energyefficiency.org/new-energy-efficient-building-code-in-ontario-best-in-north-america/>.
9 Chief Energy Conservation Officer, *2006 Ontario Power Authority Annual Report,* "Ontario – A New Era in Electricity Conservation" (Toronto: OPA, 2006) at 65.

were required to meet a cost effectiveness test called the Total Resource Cost Test. This test has been criticized for a number of reasons, foremost being that it does not include environmental or social externalities.[10] To date, savings from these programs are estimated to be more than 1,000 million m^3 from 2007 to 2012.[11]

In 2004, the Ontario government granted electricity distributors an increase in their rates by $163 million by way of the third installment of their incremental Market Adjusted Revenue Requirement (MARR) provided they invested an equivalent amount in CDM funding. Most Local Distribution Company's (LDCs) in Ontario then launched a range of conservation programs which were estimated to have reduced peak demand by 357 MW.[12]

Also in 2004, the Electricity Conservation & Supply Task Force issued its report which called for the creation of a "conservation culture," the creation of a conservation champion and, like the Porter Commission, recommended that demand reduction be evaluated on a level basis with supply alternatives.[13]

The Conservation Bureau was established within the Ontario Power Authority in 2005; over the next 10 years, it launched a broad range of conservation programs delivered by LDCs as well as various associations and private companies. These programs were funded by all electricity ratepayers with approval provided by ministerial directives. Its initial target of 1350 MW by 2007[14] was achieved and total savings to 2013 are estimated to be 1900 MW and 8.6 TWh.[15] In recognition of the challenges associated with conservation mentioned earlier (hard to see and measure), over 150 conservation events were celebrated each year and a detailed Evaluation, Measurement & Verification protocol was developed.

One final noteworthy initiative was the installation, completed in 2013, of smart "time-of-use" meters and time-of-use rates for all 4.3 million residential customers, the first jurisdiction in North America to make this important investment. Although an independent study concluded that Ontario's roll-out aligned with best practices in four out of six characteristics, it found the 1.9:1 ratio of peak to off-peak prices to be far below the optimal ratio of 4.9:1.[16]

THE PRESENT

Following consultations, the Ontario government released it Long-Term Energy Plan, "Achieving Balance" in 2013.[17] Although called an energy plan, it is almost entirely an electricity plan, with no mention of conservation of natural gas or oil. It noted that conservation will be the first resource to be considered for electricity planning and set a target of 30 TWh by 2032 (16 per cent reduction in forecast gross demand) with 7 TWh by 2020 and 2500 MW of demand response. It also released "Conservation first: A Renewed Vision for Energy Conservation in Ontario"[18] which, like the Long-Term Energy Plan made no mention of natural gas or oil conservation. It did however make clear the government's' commitment to conservation first and that the Local Distribution Companies (LDCs) would have an expanded role with more autonomy and programming choice. In 2015, LDCs will be submitting their conservation programs individually or in groups to the Independent Electricity System Operator, which now includes OPA, for approval.

10 Mark Winfield, "An Efficient Balance? Applying the Total Resource Cost Test to CDM Initiatives of local Electricity Distribution Companies in Ontario: Assessment and Recommendations for Reform", York University Faculty of Environmental Studies (Toronto: June 2009) at 35.

11 Ontario Energy Board, *Demand Side Management Framework for Natural Gas Distributors (2015 – 2020)* (Toronto: OEB, December 2014) at 10 [*OEB Guidelines*].

12 Chief Energy Conservation Officer, "Taking Action – Supplement: Conservation Results 2005-2007", (OPA: Toronto, 2008).

13 Pratt, Courtney & Electricity Conservation and Supply Task Force, *Tough Choices: Addressing Ontario's Power Needs-Final Report to the Minister (2004);* See also *Mallinson, supra* note 7 at 161.

14 Chief Energy Conservation Officer, Annual Report 2008: *Be the Change to a Culture of Conservation*, (Toronto: OPA, November 2008) at 1, 17.

15 Ontario Ministry of Energy, *Conservation First: A Renewed Vision for Energy Conservation in Ontario* (Toronto: Ministry of Energy, December 2013) at 17 [*Conservation First*].

16 The Brattle Group, *Assessing Ontario's Regulated Price plan: A White Paper,* Toronto: OEB, 2011.

17 Ontario, Ministry of Energy, *Achieving Balance: Ontario's Long Term Energy Plan*, (Toronto: Ontario Ministry of Energy, December 2013) [*Achieving Balance*].

18 *Conservation First*, *supra* note *15*.

In recognition of some of the limitations of the TRC test, the government now allows a 15 per cent adder to be added onto the benefits of a conservation program. This was an attempt to account for at least some of the externalities that are not included in current program evaluations.

An analysis of Ontario's electricity conservation targets found that, while its past targets were more aggressive, its 2030 target would rank 17th compared to targets set by US states.[19]

Although most well known for promoting the use of renewable energy, the *Green Energy Act* of 2009 also included a few important conservation initiatives. It required the Environmental Commissioner of Ontario to report on Ontario's progress on conservation and to make recommendations on what further action is required. Recent annual reports have noted that further investments should be made in natural gas conservation programs, that there is a total lack of conservation programs for oil and oil products such as transportation fuel and that there should be a greater price differential between off peak and on peak electricity rates.[20]

Another important initiative of the *Green Energy Act* required all public agencies (municipalities, universities, schools and health care (MUSH)) to submit energy consumption/green house gas emissions by 2013 and a plan to reduce energy/GHG by 2014. Despite there being no penalty for non-compliance, over 90 per cent of all such organizations have submitted their data and more than 80 per cent have submitted their plans. This is expected to result in major investments and savings in these sectors in the future.

In late 2014, the Ontario Energy Board issued CDM Guidelines for electricity distributors and DSM Guidelines for natural gas distributors.[21] While the electricity guidelines focused on achieving the government's target of 7 TWh by 2020, the natural gas guidelines had no such target. One of the most important features of the natural gas guideline is that it recommended DSM budgets increase from $65 million to $155 million/year.[22]

Unlike the electricity and natural gas conservation programs that are funded by their respective ratepayers in Ontario, at the federal level all energy conservation activities are funded out of general revenue. This has resulted in the cancellation of federal incentive programs (such as EcoEnergy for home energy retrofits) with a focus on providing product information/labelling, support for various tools (such as EnerGuide rating for homes), Minimum Energy Performance standards (MEPS), etc.

THE FUTURE

Although as is clear from the previous two sections that much has been achieved, much more remains to be done. Here are some of the most important developments needed for the full potential for conservation to be realized in Ontario.

- **Culture of Conservation** – As noted earlier, the need for a move to a conserver society was first identified in 1973 and a culture of conservation was first promoted in 2004. In 2011, the Canadian Council of Chief Executives (composed of 150 CEOs of largest enterprises in Canada) called for the building of a culture of energy conservation in Canada.[23] While limited progress has been made, much remains to be done before saving energy comes as natural to Canadians as dressing warmly in the winter. All mandatory as well as voluntary programs should all be framed in such a way that they are seen as being part of a move to this new culture.
- **Customer/Tennant Engagement** – One of the principal vehicles for bringing about a new culture of conservation is the direct engagement of energy customers and tenants in voluntary energy conservation programs.

19 *Mallinson, supra* note 7 at 32.

20 Environmental Commissioner of Ontario, "Looking for Leadership: Annual Greenhouse Gas Progress Report – 2014", (Toronto: Environmental Commissioner of Ontario, 2014) at 33.

21 *OEB Guidelines, supra* note 11.

22 *Ibid* at 17-18.

23 Canadian Council of Chief Executives, "Energy-Wise Canada: Building a Culture of Energy Conservation", (December 2011) online: Canadian Council of Chief Executives, <http://www.ceocouncil.ca/wp-content/uploads/2011/12/Energy-Conservation-Paper-FINAL-December-20111.pdf>.

Important progress has been made here by a number of leaders but there is vast scope for progressive programs.

- **Supply Subsidies** – While conservation is already cost effective (in Ontario, every $1 invested in energy efficiency avoided $2 in costs to the electricity system),[24] it would be an even more valuable if traditional energy supplies were not subsidized. A recent study by the International Monetary Fund estimated the direct support to energy producers to be over $1.5 billion and over $30 billion in uncollected tax on externalized costs such as carbon emissions.[25] And as more provinces join BC, Quebec, Alberta (to a more limited extent) and soon Ontario in having a price on carbon, the advantage of carbon free conservation will be even larger. The federal government may be forced, politically, to establish a national carbon pricing program, as recommended by the Canadian Council of Chief Executives.[26]

- **Smart Energy Network** – As the electricity grid and other energy networks get smarter, conservation should play a larger role and take advantage of new smart technologies. Future smart appliances will know when energy prices are lower and shift demand automatically. The waste heat energy from some appliances (refrigerators, dishwashers, etc) will be used to preheat water for others. These new technologies will automate behaviour change. And the ratio between on peak and off peak electricity rates should be increased to closer to the optimal level of 4.9:1.

- **Integration of Electricity/Natural Gas Conservation Programs** – Energy consumers do not want to hear about one type of program offered by electricity utilities and a different one offered by gas utilities.

- **Existing Buildings** – While great progress has been made in encouraging builders of both new homes and commercial buildings to voluntarily certify their buildings to higher standards (e.g. EnergyStar and LEED, respectively), much less progress has been made on existing buildings. With 1-1.5 per cent of new stock being added each year, existing buildings will continue to make up the majority of our building stock. Initiatives are underway at both the local and provincial level to require reporting on building performance which will drive energy efficiency retrofits.

- **Evaluation, Measurement & Verification** – Ontario has become a leader in the development and implementation of independent program evaluations and has allocated up to 5 per cent of program budgets. This is particularly important as measuring energy efficiency requires the use of comprehensive protocols.

- **Codes & Standards** – Easily forgotten, mandatory minimum energy efficiency codes and standards continue to play a critical role in reducing energy demand. Energy planners love this approach as they are reliable.

- **Transportation** – And finally, it is critical that major initiatives be undertaken in transportation which is responsible for 34 per cent of energy consumption In Ontario.[27]

While it is clear that a good start has been made in conserving energy in Ontario, it is equally clear that there remains a great deal more to do. Creating a true “Culture of Conservation” will take leadership and engagement by all sectors of society. ■

---

24 *Conservation First*, *supra* note 15 at 1.

25 Mitchell Anderson, “IMF Pegs Canada’s Fossil Fuel Subsidies at $34 Billion”, *The Tyee* (15 May 2015), online: The Tyee <http://thetyee.ca/Opinion/2014/05/15/Canadas-34-Billion-Fossil-Fuel-Subsidies/>.

26 Canadian Council of Chief Executives, “Framing an Energy Strategy for Canada: Submission to the Council of the Federation”, (July 2012) at 10, online: Canadian Council of Chief Executives <http://caid.ca/FraEneStrCanSub2012.pdf>.

27 Ontario, Ministry of the Environment and Climate Change, *Ontario’s Climate Change Discussion Paper 2015* (Toronto: Ministry of Environment and Climate Change, 2015) at 30.

CONSERVATION FIRST: IN THEORY AND PRACTICE

*Jack Gibbons**

In December 2013, Premier Kathleen Wynne's Government adopted a policy of *Conservation First* with respect to electricity and natural gas.[1]

Conservation First means investing in all cost-effective and achievable energy efficiency resources before investing in new supply.

This new policy is both revolutionary and common sense.

It is revolutionary because the Government of Ontario's preferred option for meeting our electricity needs for more than 100 years has been the construction of large centralized electricity generating stations. For example, one of the justifications for the Government's previous *Long-Term Energy Plan*, was that it would retain "the maximum number of high-quality, high-paying nuclear industry jobs in the province while providing opportunities for long-term growth of the nuclear industry."[2]

It is also common sense for the following reasons:

- It will lead to lower energy bills;
- It will lead to lower greenhouse gas emissions;
- By raising the energy productivity of our manufacturing and resource industries it will increase their competitiveness, which will lead to GDP and job growth;
- It will reduce the outflow of Ontario dollars to Western Canada and Pennsylvania to purchase natural gas and to Saskatchewan to purchase uranium, which will also lead to more jobs in Ontario.

Unfortunately, two of Ontario's energy agencies, the Independent Electricity Operator (IESO) and the Ontario Energy Board (OEB) are failing to implement Premier Wynne's *Conservation First* policy.

IESO

The IESO is responsible for long-term planning with respect to Ontario's electricity system. Unfortunately, it does not have a plan or a budget to achieve all of our feasible and cost-effective energy savings opportunities.

Furthermore, Ontario's electricity savings targets are substantially lower than those of leading U.S. jurisdictions. For example, the goal of Ontario's electricity conservation programs is to reduce Ontario's total electricity consumption by less than 1 per cent per year between now and 2020.[3] In contrast, the annual electricity savings targets of Massachusetts, Rhode Island and Vermont are 2 per cent or greater.[4]

---

* Jack Gibbons is the Chair of the Ontario Clean Air Alliance. In addition, Mr. Gibbons assists Environmental Defence with its Ontario Energy Board interventions.

[1] Ontario, Ministry of Energy, *Achieving Balance: Ontario's Long Term Energy Plan*, (Toronto: Ontario Ministry of Energy, December 2013) [*Achieving Balance*] at 3, 20.
[2] Ontario, Ministry of Energy, *Ontario's Long-Term Energy Plan: Building Our Clean Energy Future,* (Toronto; Ministry of Energy, November 2010) at 23-25.
[3] Ontario's electricity savings target for 2020 is 7 TWH. In 2014 Ontario's total electricity consumption was 139.8 TWH. Ontario Power Authority, *Conservation First Framework Update: Presentation to SAC* (June 24, 2014), at 7 - 8 [*Presentation to SAC*]; IESO, "2014 Electricity Production, Consumption, Price and Dispatch Data", online: IESO <http://www.ieso.ca/Pages/Power-Data/2014-Electricity-Production-Consumption-and-Price-Data.aspx>.
[4] American Council for an Energy-Efficient Economy, *The 2014 State Energy Efficiency Scorecard* (October 2014), online: ACEEE at 38 <http://aceee.org/research-report/u1408>.

As Figure 1 reveals, the cost of saving electricity (3.5 cents per kWh) is 60 per cent to 80 per cent lower than the forecast cost of new electricity supply from a re-built Darlington Nuclear Station (8.9 to 16.6 cents per kWh). Nevertheless, the IESO's 2015-2020 electricity conservation budget ($2.4 billion)[5] is 80 per cent lower than Ontario Power Generation's "high-confidence" estimate of the cost of re-building Darlington ($12.9 billion).[6]

OEB

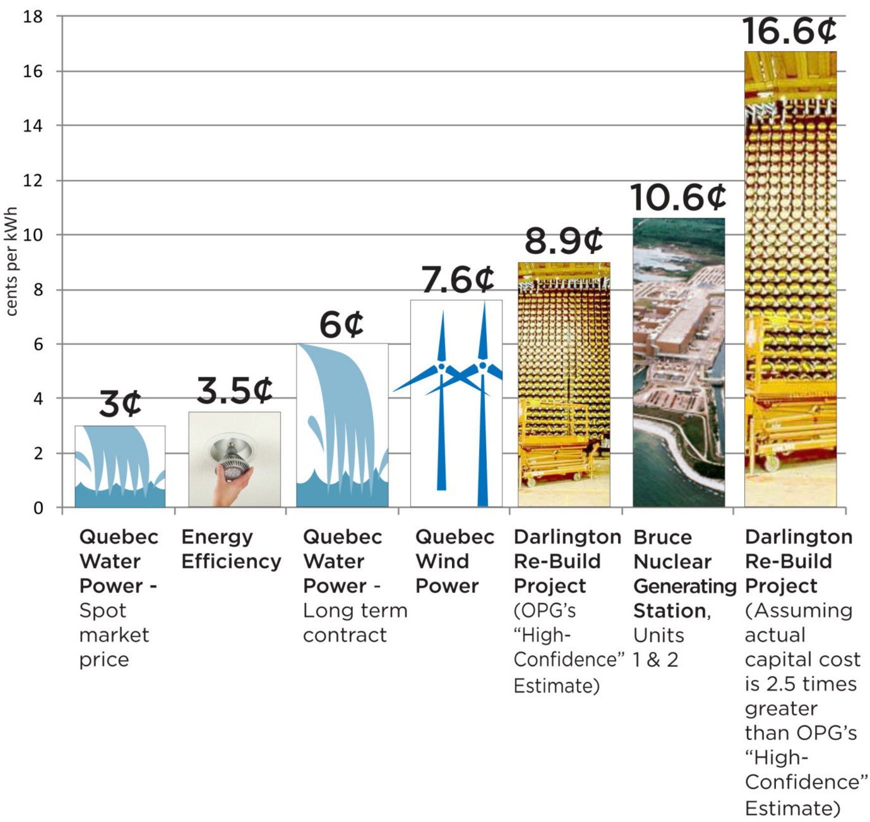
The OEB is implementing policies which will frustrate the achievement of Conservation First with respect to both electricity and natural gas.

Residential Rate Design

Historically, Ontario's electricity distribution utilities (e.g., Hydro Ottawa, Toronto Hydro) recover their costs of distributing electricity from their residential customers through a combination of a fixed monthly charge and a volumetric distribution charge based on the number of kilowatt-hours (kWh) consumed.

The fixed monthly charge does not vary with a

Figure 1: Ontario's Electricity Options a Cost Comparison[7]



[5] *Presentation to SAC*, *supra* note 3 at 7-8.
[6] *Re Ontario Power Generation Inc, Payment Amounts for Prescribed Facilities for 2014 and 2015 (Decision with Reasons)* (20 November 2014), EB-2013-0321, online: OEB at 54 <http://www.ontarioenergyboard.ca/oeb/_Documents/Decisions/dec_reasons_OPG_20141120.pdf>.
[7] Ontario Clean Air Alliance Research, *Ontario's Electricity Options: A Cost Comparison* (1 October 2014) <http://www.cleanairalliance.org/wp-content/uploads/2014/10/options2.pdf>.

customer's electricity usage and is the same for all customers irrespective of whether they live in a small apartment or a mansion.

The volumetric distribution charge varies with electricity usage. As a result, the volumetric charge provides consumers with a reward for conserving electricity.

However, the OEB has recently decided to require all electric utilities to eliminate their volumetric distribution charges for residential consumers and to recover all of their distribution costs through their monthly fixed charge.[8]

At the present, on average, Ontario's electric utilities recover approximately 50 per cent of their residential distribution costs from their fixed monthly customer charges and the remaining 50 per cent from their volumetric distribution charges. Therefore for the average residential consumer, the OEB's proposal would lead to a doubling of their fixed monthly customer charge.

Eliminating the volumetric charge will undermine Premier Wynne's *Conservation First* policy by reducing consumers' incentive to save energy and their ability to reduce their bills. For example, elimination of Toronto Hydro's 1.5 cents per kWh volumetric distribution charge would reduce its residential customers' financial incentive to conserve electricity by 8 to 13 per cent.[9]

Conserving electricity is in the financial self-interest of all consumers since it reduces the need for new high-cost electricity generation, transmission and distribution infrastructure that pushes up everyone's electricity rates.

The OEB's policy is also unfair since the cost of providing electricity distribution service to a large home is much greater than providing service to a small home. That is, recovering 100 per cent of a utility's distribution costs via a uniform, fixed monthly charge will overcharge small homeowners and undercharge large homeowners. It is Robin Hood in reverse.

According to the OEB, it also plans to implement this policy for the customers of Enbridge Gas Distribution and Union Gas in the future.[10]

Natural Gas Utility Conservation Programs

In March 2014 Ontario's Energy Minister, Bob Chiarelli, issued a legally-binding directive to the OEB to create a new Demand Side Management (DSM) Framework which would "enable the achievement of all cost-effective DSM."

On December 22, 2014, the OEB issued its new *Demand Side Management Framework for Natural Gas Distributors (2015-2020)*.[11] Unfortunately, its new Framework is contrary to the Conservation First directive that it received from Energy Minister Chiarelli. Specifically, it failed to create a regulatory framework that will enable the achievement of all cost-effective DSM. Instead it:

1. Capped Enbridge's and Union's conservation budgets at $75 million and $60 million respectively;
2. Directed Union Gas to make optional one of the most cost-effective energy conservation programs in North America; and
3. Limited the profit incentive for Enbridge and Union to expand their energy conservation programs and budgets.

Conservation Budget Caps

The OEB's decision to arbitrarily cap the gas utilities' conservation budgets will prevent the achievement of all cost-effective DSM resources.

While the new budget levels set by the OEB represent a significant increase in spending, it is worth noting that the gas utilities' new

---

[8] Ontario Energy Board, *Board Policy: A New Distribution Rate Design for Residential Electricity Consumers, EB-2012-0410* (April 2, 2015) [*OEB Rate Policy*].
[9] Ontario Clean Air Alliance Research, *Doubling the Fixed Monthly Customer Charge;* A Review of the Ontario Energy Board's Proposal to Guarantee the Residential and Small Business Distribution Revenues of Ontario's Electric Utilities (May 2014).
[10] *OEB Rate Policy*, *supra* note 8 at 2-3.
[11] Ontario Energy Board, *Report of the Board: Demand Side Management Framework for Natural Gas Distributors (2015-2020)* (OEB, 22 December 2014) [*OEB DSM Report*].

combined maximum annual conservation budget is still 65 per cent lower than Ontario's annual electricity conservation budget despite the fact that our natural gas consumption is more than 50 per cent greater than our electricity consumption.

According to the OEB, its arbitrary budget caps are appropriate since it assumes that many customers will not be able to participate in energy conservation programs. However, this assumption ignores the fact that virtually all of the gas utilities' customers have participated in the utilities' previous conservation programs. For example, in 2013, 82 per cent of Union Gas' large volume industrial customers took advantage of its energy efficiency incentives.

According to a Navigant Consulting report,[12] Enbridge would need an energy conservation budget in excess of $200 million per year to achieve 50 per cent of the cost-effective DSM in its franchise areas by 2024. Energy conservation programs on this scale would lead to a $9.7 billion (2015$) net reduction in energy bills.

A steady increase in the gas utilities' DSM budgets to $200 million per year each by 2020 would raise gas rates by approximately 1 per cent per year. However, actual bills would fall since the percentage reduction in natural gas consumption would be greater than the percentage increase in rates. In addition, it is important to remember that natural gas commodity costs have fallen by 35 per cent since 2010.[13]

The rate impact of larger DSM budgets can also be offset by changing the way these efficiency investments are treated. For example, the rate impacts of supply side infrastructure investments (e.g., the GTA Gas Pipeline) are minimized by amortizing their costs over the expected economic life of the infrastructure. On the other hand, 100 per cent of the costs of the utilities' conservation investments are recovered from ratepayers during the year in which they are incurred (even if the measure, such as a new furnace, will be in place for many years). As a result, the rate impact of a dollar invested to improve energy efficiency is much greater than the rate impact of a dollar invested in a new pipeline. Amortizing efficiency investments over the lifetime of the measure is a logical and reasonable approach for minimizing the rate impact of rising energy conservation budgets.

"De-Mandating" the Most Cost-Effective Conservation Program in North America

Union's large volume industrial energy demand-side management (DSM) conservation program, which provides financial incentives to stimulate energy productivity investments, is the most cost-effective energy conservation program in North America.

On average, each dollar that Union provides to its industrial customers to encourage them to invest in energy efficiency leads to $54 of total resource cost (TRC) savings which is the net present value of all the energy savings generated from a DSM program (including gas, water, and electricity), while subtracting the costs for the DSM technologies as well as the program costs.

In 2013, this program was responsible for 77 per cent of the $326 million of TRC savings created by all of Union's energy conservation programs.

Nevertheless, the OEB is directing Union to eliminate these financial incentives that generate these huge bill savings. According to the OEB, financial incentives are not necessary since "these customers are sophisticated and typically competitively motivated to ensure their systems are efficient." However, this assertion ignores two important facts.

First, Ontario's industries are not undertaking all of their cost-effective energy efficiency investments. According to a Canadian Manufacturers & Exporters report, if all the remaining economically feasible best practices were implemented, Ontario's total industrial energy consumption would fall by 29 per cent by 2030 relative to the business as usual scenario.

Second, our manufacturing companies often require a payback period of one year or less for their energy efficiency investments. As a result, financial incentives are necessary to motivate them to make cost-effective energy productivity

[12] Navigant Consulting Inc, *Natural Gas Energy Efficiency Potential Study: Final Report Prepared for Enbridge Gas Distribution* (15 January 2015), at xii, 118.
[13] Ontario Clean Air Alliance Research, *Reducing Ontario's Greenhouse Gas Emissions Due to Natural Gas Consumption* (January 26, 2015), online: OCAAR at 3 <http://www.cleanairalliance.org/wp-content/uploads/2015/03/gas-ghgs.pdf>.

investments that have payback periods greater than one year.[14]

In response to the OEB decision, Union Gas is proposing to *increase* its annual energy conservation budget by 97 per cent between 2013 and 2020. However, as a result of the cancellation of its most cost-effective energy conservation program, its total annual energy savings will *fall* by 55 per cent.[15]

Limiting the Profit Incentive for the Gas Utilities to Grow their Energy Conservation Programs and Budgets

In the past, the OEB linked Enbridge's and Union's profits to the size of their energy conservation programs and budgets. By expanding their programs and budgets, the gas utilities could increase their profits. The OEB has now severed this link.

According to the OEB's new rules, the maximum annual DSM profit bonus will be $10.45 million and it "will not be a function of the gas utilities' DSM budget. The incentive amount available will not increase or decrease relative to approved DSM budgets, and is not to be increased annually for inflation."[16]

As a consequence, the gas utilities no longer have a profit incentive to seek OEB approval for bigger and better conservation programs to create larger bill savings for their customers. On the contrary, as a result of the OEB's decision, the gas utilities must increase their natural gas throughput volumes and their supply-side infrastructure to increase their profits.

Conclusion

The IESO and the OEB are needlessly harming our economy and environment by failing to implement Premier Wynne's *Conservation First* policy. ■

---

[14] *Ibid* at 4.
[15] In 2013 Union Gas' conservation budget was $32,838,926 and its 2013 conservation programs will lead to cumulative gas savings of 2,820,834,405 cubic metres. It is now seeking OEB approval for a 2020 conservation budget of $64,714,000 which is forecast to produce 1,280,000,000 of cumulative gas savings. See Union Gas, *Final Demand Side Management 2013 Annual Report,* (4 November 2014), at 17-18; *Union Gas Limited Application for approval of 2015-2020 Demand Side Management Plans* (Application) (1 April 2015), EB-04-0029, OEB at Exhibit A (Tab 3), p 6, p12.
[16] *OEB DSM Report*, *supra* note 11 at 22.

THE REFORM OF THE RENEWABLE ENERGY ACT IN GERMANY

Ralf Thaeter and Silke Goldberg***

1. Introduction

The act for the Reform of the Renewable Energy Act[1] (the "**Reform Act**" or **"EEG"**) was approved by the German Bundestag on 27 June 2014 and on 11 July by the German Upper House. It entered into force on 1 August 2014.

Sigmar Gabriel, German minister of Economy and Energy, stressed that the reform would provide a reliable but ambitious expansion path for renewable energy. Whereas previous German governments emphasized the increase of renewable energy generation capacity, the Reform Act has four main objectives:

1. Continuing and controlling the expansion of renewable energy
2. Lowering the cost of funding
3. Spreading the financial burden more fairly
4. Improving the market integration of renewable energy

The main objective of the Reform Act is to reconcile cost effectiveness, environmental compatibility and security of supply, three concerns that have often been referred to as the "energy trilemma".

In spite of the emphasis on cost control, the German government is keen to point out that the long-term objective of generating 80% of electricity through renewable resources has not changed. The expansion of renewable energy in Germany is set to continue, albeit at a slower pace.

2. Continuing and Controlling the Expansion of Renewable Energy

The Reform Act stipulates specific targets as to the portion that energy generated from renewable sources should make up in the future:

- until 2025, this portion should total 40-45 per cent; and
- until 2035, this portion should total 55-60 per cent.

Additionally, the Reform Act sets targets for annual expansion of specific technologies:

- Installed capacity for solar power should increase by 2,500 MW annually.
- Installed capacity for on-shore wind farms should be 2,500 MW.

In order to regulate the expansion of onshore

* Dr Ralf Thaeter holds a Doctor of Laws (Dr. iur.) from the University of Passau and a Master of Laws from the American University, Washington D.C. He is head of HSF's German practice and specialises in corporate law, with a focus on public and private M&A, cross-border work, general corporate advisory and capital markets. His sector focus covers energy (in particular gas, power and renewables), regulated industries and private equity.
** Silke Goldberg is counsel in HSF's Berlin office and specialises in European energy law. She is admitted to practice as a solicitor in England and a member of the Berlin Bar (Rechtsanwaltskammer Berlin). She has extensive experience of advising on complex international power projects, in particular in relation to the structuring of JV co-operations and related shareholder documents and regulatory aspects.

[1] Erneuerbare-Energien-Gesetz vom 21. Juli 2014 (BGBl. I S. 1066), das zuletzt durch Artikel 1 des Gesetzes vom 22. Dezember 2014 (BGBl. I S. 2406) geändert worden ist

wind capacity, the EEG now contains an expansion target of net 2,400-2,600 MW/year for onshore wind power plants for the first time.

- The annual increase for biomass has been set at no more than 100 MW
- Off-shore wind capacity has a target of 6,500 MW by 2020 and of 15,000 MW by 2030.

3. Lowering the Costs

The objective of the Reform Act is to reduce the financial burden of the support programme for renewable energy generation. In order to achieve this objective, the Reform Act will reduce the support levels – with the introduction of technology specific tariffs which apply to all new plants commissioned after 1 August 2014, further details and technology specific differences are set out below.

Onshore Wind

The Reform Act introduces a number of changes for onshore wind; one of the consequences that was predicted was a "race to commissioning" in 2014 to receive assistance from the old support regime followed by a somewhat slower year in 2015.

From 1 August 2014, the tariff for newly commissioned onshore wind decreased every quarter by 0.4 per cent (compared to the immediately preceding quarter) subject to the overall expansion of installed onshore wind capacity remaining within the target corridor of 2,400 – 2,600M W/year. Should this target corridor be exceeded, the rate of decrease will be accelerated accordingly. On the other hand, should the lower end of the target corridor (the "Onshore Target Floor") not be reached, the tariff will be adjusted accordingly.

If the target is exceeded by

- up to 200 MW, the reduction will be 0.5 per cent;
- more than 200 MW, the reduction will be 0.6 per cent;
- more than 400 MW the reduction will be 0.8 per cent;
- more than 600 MW the reduction will be 1.0 per cent; and
- more than 800 MW the reduction will be 1.2 per cent

If the Target Floor is not reached in the relevant period, the monthly reduction of the applicable value is decreased. For a shortfall of the Target Floor by up to 200 MW, the reduction is decreased by 0.3 per cent; for a shortfall of the Target Floor by more than 200 MW, the reduction is decreased by 0.2 per cent; and if the Target Floor is not reached by more than 400 MW, the tariff will not be reduced.

The central problem in this new approach however is that the actual tariff for each quarter will only be known, at the earliest, five months prior to its entry into force and is calculated on the basis of the reaching or otherwise of the Onshore Target Floor in the period from the last calendar day of the 18th month prior and the first calendar day of the fifth month prior to the relevant quarter. This introduces a level of uncertainty into any project's financial plans which in turn are not within the control of the project itself but determined by the speed with which its competing projects are commissioned. This scenario could lead to some interesting market dynamics in the future but will likely increase the difficulty of financing onshore wind projects.

In another significant change to the previous onshore wind regime, the Reform Act introduces changes to the reference yield model ("*Referenzertragsmodell*" in German). In this model, the tariff for onshore wind sets out a higher tariff for an initial period of time and a lower rate for the remainder of the 20 years (plus year of commissioning) in which the support tariff applies.

Offshore Wind

The Reform Act also introduces a number of changes to the offshore regime.

The Reform Act introduces, by means of an amendment to the German Energy Industry Act ("*Energiewirtschaftsgesetz*" in German), a new mechanism for the allocation of grid connection capacity for new capacity of up to 6,500 MW up to 31 December 2020. From 1 January 2021 onwards, the grid connection available for allocation capacity will increase by 800 MW/year.

In the case of demand beyond these capacity targets, the relevant additional grid connection capacity will be allocated in an auction. Should a wind project fail to use its allocated grid capacity, the competent authority, the German Federal Maritime and Hydrographic Office may, subject to certain conditions, revoke allocated grid connection capacity.

It is possible that this new mechanism will make the already difficult process of offshore grid connection more complicated for projects. Further, it remains to be seen whether this process will help to alleviate the pressure on the two offshore Transmission Service Operators (TSOs) to provide timely grid connections.

However, the structure of the current tariff regime remains largely unchanged and the availability of the popular acceleration model pursuant to which an increased tariff applies for the first eight years has been extended to plants commissioned prior to 1 January 2020.

There are two different approaches of remuneration for offshore wind farms which commence operation before 1 January 2020. Wind farm operators can choose between:

i. claiming the ‘initial remuneration’ of 15.4 cents/kWh over a period of 12 years; or

ii. claiming an ‘initial remuneration’ of 19.4 cents/kWh for a total of 8 years (the so-called optional acceleration model).

After 12 or 8 years, as applicable, the remuneration returns to a fixed level of 3.9 cents/kWh.

Under certain circumstances, the initial remuneration of 15.4 cents/kWh can be extended beyond the period of 12 years, depending on the distance between the wind farm and the coast and the water depth at the location. The period in which the increased initial remuneration of 15.4 cents/kWh is paid is extended by 0.5 months for every full nautical mile of distance between the system and the coast over twelve nautical miles and by 1.7 months for each full metre of water depth exceeding a depth of 20 metres.

The possibility of extension also applies to wind farms for which the operator has selected the higher rate of remuneration of 19.4 cents/kWh for a period of 8 years in accordance with the acceleration model.

Regardless of whether or not the operator has chosen the acceleration model, if the remuneration period is extended, 15.4cents/kWh will be paid out during the extension period.

Overview of Applicable Feed-in-Tarrifs (FiTs) for Offshore Wind Farms Pursuant to the Reform Act

Year of Commissioning	Basic remuneration [ct/kWh]	Higher initial remuneration [ct/kWh]	Initial remu-neration in the accelerated model [ct/kWh]
2015	3,9	15,4	19,4
2016	3,9	15,4	19,4
2017	3,9	15,4	19,4
2018	3,9	14,9	18,4
2019	3,9	14,9	18,4
2020	3,9	14,9	18,4
2021	3,9	13,9	-
2022	3,9	13,4	-

The Reform Act does not introduce structural changes to the support regime for solar (photovoltaic) installations; it specifies an expansion corridor of newly built capacity of 2,400-2,600 MW/year (the “**Solar Target Corridor**”). The slightly changed tariff structure for solar plants will be applicable to plants commissioned from 1 September 2014 onwards.

The applicable value depends on the installed capacity of the plant.

For up to and including 10 MW it is 9.23 cent/kWh provided that –

i. the plant is affixed to, in or on a building and the building is predominantly used for purposes other than the generation of electricity from solar power

ii. certain zoning law provisions are complied with.

If the plant is affixed to, in or on exclusively on a building or a noise protection wall, the applicable value is for an installed capacity of –

- up to and including 10kW 13.15 cent/kWh
- up to and including 40 kW 12.80 cent/kWh
- up to and including 1 MW 11.49 cent/kWh
- up to and including 10 MW 9.23 cent/kWh

Reduction of Financial Support

From 1 September 2014 the applicable value is reduced monthly by 0.5 per cent relative to the applicable value in the previous month.

The monthly reduction is reviewed and increased or decreased every quarter, depending on whether or not the Solar Target Corridor has been met or exceeded. If the Solar Target Corridor has been exceeded in the relevant period (the period between the last day of the 4th month and the first day of the last month preceding the review) the monthly reduction of the applicable value is increased.

For an excess of –

- up to 900 MW to 1.00 per cent
- more than 900 MW to 1.40 per cent
- more than 1,900 MW to 1.80 per cent
- more than 2,900 MW to 2.20 per cent
- of more than 3,900 MW to 2.50 per cent
- more than 4,900 MW to 2.80 per cent.

If the Solar Target Corridor has not been met in the relevant period, the monthly reduction of the applicable value is decreased.

For a shortfall of –

- up to 900 MW to 0.25 per cent
- more than 900 MW to nil
- more than 1,400 MW to nil; the applicable value is increased by 1.50 per cent once on the first day of the applicable quarter.

4. **Spreading the Burden More Fairly**

In Germany, the cost of the support regime for renewable energy is socialized and largely borne by industrial and domestic consumers through the mechanism of a charge (the "Reallocation Charge") which is added to electricity bills. In the past, large industrial consumers enjoyed an exemption from this reallocation charge. This exemption regime was subject to criticism from the European Commission. One of the objectives of the Reform Act is to spread the burden of the Reallocation Charge more fairly and to revoke or limit any exemptions.

Self-Supply

Under the Reform Act, self-supplying entities with an installed capacity of more than 10kW will be subject to the Reallocation Charge.

For self-supply from renewable energy plants commissioned after 1 August 2014 a reduced rate of the Reallocation Charge will be payable. The reduced rate is 30 per cent until the end of 2015, 35 per cent in 2016 and from 2017 onwards 40 per cent of the full amount.

Energy-Intensive Corporations

Under the applicable regime prior to the Reform Act, energy-intensive corporations were exempt from the Reallocation Charge. Under the Reform Act, exemptions will be limited to corporations and specified sectors characterised by high energy costs, intensity of trade and subject to international competition that depend on the exemption to remain competitive. Eligible sectors are categorised into two lists ("List 1" and "List 2", respectively) which are annexed to the Reform Act.

In order to apply for an exemption a corporation from an eligible sector will need to provide evidence of the following:

- a certain minimum of energy consumption in the preceding financial year; and
- that its energy costs make up at least 16 per cent (17 per cent from 2015) of their gross value (for List 1 sectors) or at least 20 per cent of gross value (for List 2 sectors).

Companies benefitting from an exemption are likely to have to pay at least a certain amount of the Reallocation Charge, ie they will have to pay the full Reallocation Charge for the first GWh consumed, and thereafter, for every kWh 15 per cent of the full Reallocation Charge. The amount payable is subject to a cap (or super-cap) of 4 per cent of gross value of the corporation (the "cap") and 0.5 per cent of the gross value of the corporation (the "super cap"). The super cap applies to companies with energy costs of more than 20 per cent of their gross value. Regardless of any applicable cap, the minimum amount payable will be 0.1 cent/kWh or 0.05 cent/kWh for corporations operating in the nonferrous metals sector.

5. Improving the Market Integration of Renewable Energy

Compulsory 'Direct Marketing'

Direct marketing refers to the selling of renewably generated electricity directly to another market participant at market prices rather than to the TSO under the applicable feed-in-tariff.

Under the regime prior to the introduction of the Reform Act, direct selling was used by some large plant operators in peak times to achieve an electricity price above the feed-in-tariff. The Reform Act introduces an element of compulsory direct marketing:

- for plants with an installed capacity in excess of 500 kW from 1 August 2014; and
- for smaller plants with an installed capacity of more than 100 kW from 1 January 2016.

Plants with a lower installed capacity remain entitled to a feed-in tariff as well as plants with an installed capacity of up to 250 kW commissioned between 31 December 2015 and 1 January 2017.

For operators subject to the direct marketing regime, the feed-in-tariffs will effectively only be available as an emergency back-up in that such operators will only receive a reduced tariff in case of a switch back to the FIT.

Introduction of Tendering

Under the regime prior to the Reform Act, TSOs were subject to a compulsory purchase obligation and as such had to take off, transmit and distribute any renewably generated electricity and pay the producer on the basis of statutory feed-in-tariffs.

The Reform Act introduces, for the first time, the concept of tenders for solar plants on open land by way of a pilot project. If this is successful, the government plans to introduce tendering for all renewable energy sources. The Reform Act does not specify the details of the intended tendering regime – this will be addressed in subsequent secondary legislation.

6. Impact on Current and Future Renewable Energy Projects

What Happens to Existing Plant?

Offshore wind

The pre-Reform Act tariffs will continue to apply to:

- plants commissioned before 1 August 2014; and
- plants with a commissioning date between 1 August 2014 and 31 December 2014 if the developer obtained the licence under the Federal Emission Control Act (*Bundesimmissionsschutzgesetz*) on or before 22 January 2014.

For all other projects, the support regime of the Reform Act will apply.

Existing biogas plants

In general, the financial support provisions at the time of commissioning are applicable. However, support for subsequent capacity additions is capped at the output achieved in 2013 or 95 per cent of the installed capacity on 31 July 2014, whichever is the higher.

Operators of existing plants are entitled to €130 per kW flexibly provided additional installed capacity per year subject to the additional electricity being made available to the market through direct marketing.

Hydropower plants launched after 1 January 2009

If an existing hydropower plant with an installed capacity of more than 5MW is extended after 1 August 2014, the operator is entitled to financial support under the new rules for 20 years from the date of extension (not including the year of extension).

Where plants with an installed capacity of below 5MW are extended after 1 August 2014 the entitlements remain the same as under the previous rules.

State Aid

The Reform Act will have a yearly budget of approximately €20 billion. The EU Commission has confirmed that the measures set out in the Reform Act are compatible with the EU state aid regime, as the Reform Act supports EU environmental and energy objectives without unduly distorting competition in the European single market.

7. Outlook

The efforts of the Reform Act to introduce more market based instruments such as compulsory direct marketing and tendering procedures for new facilities which are compatible with European State Aid guidelines reflect a larger trend across the EU.

Weaning companies off from what is perceived as high levels of support with little risk has long been an ambition of many European governments as well as the European Commission as many governments have struggled to maintain the expensive support regimes put in place to achieve a higher share of renewably generated energy.

The fact that the Reform Act has, in contrast to reforms in other EU member states, not cut any tariff retroactively and, in case of offshore wind, extended the popular acceleration tariff ought to instil confidence in investors.

However, it would seem that the proposed tendering mechanism is the source of some uncertainty which will not be eliminated until the secondary legislation for the tendering procedure is in place and has been tested in practice. Commentators have also criticised the somewhat complicated benchmarking of tariffs on a quarterly basis against technology specific target corridors as these will make it more difficult to reliably predict tariff based income – which may add some difficulty for the financing of some facilities. ■

CHANGING VIEWS OF THE ROLE OF CANADIAN NATURAL GAS IN THE UNITED STATES

André Plourde[1]

Introduction

The emergence of shale production as an important component of natural gas supply in the United States has markedly altered the operating environment of the North American gas industry over the last decade or so. Prior to that, the frequently discussed, but yet-to-be-realized, potential of liquefied natural gas (LNG) imports into the United States attracted much attention from market analysts and policy-makers alike. Throughout all this, Canada remained by far the most important "foreign" source of natural gas supply for US buyers. The relative importance of imports in meeting US consumption needs, however, has fallen in recent years as US production of shale gas has continued to grow. And Canadian natural gas production has not continued to grow at the rates observed between the mid-1980s and the early 2000s.

The main objective of this paper is to consider whether the developments identified above have led to changes in the perceived future role of Canadian natural gas in the United States. How important a role is Canadian-produced gas expected to play in meeting future US natural gas consumption? How do projected LNG trade and US shale gas production affect the prospects for Canadian natural gas in the United States in the longer term? Consideration of these and related questions are at the heart of the matters to be addressed in this paper.

The remainder of the paper proceeds as follows. The next section provides information about the evolution of specific elements of natural gas markets in Canada and the United States. This information sets the context for the following section which examines projections of the role of Canadian-produced natural gas in the United States. The sources of the projections considered are the 1997 to 2014 editions of Annual Energy Outlook, a product of the Energy Information Administration, an agency of the US Department of Energy. The next section then offers reflections on implications for Canada and for gas markets in North America of the factors that underlie changes in the expected role of Canadian-produced natural gas in the United States revealed by the EIA projections. A concluding section brings together the key findings of the paper.

Elements of Context

In the second half of the 1980s, the operating environment of Canada's natural gas industry was radically transformed. In a matter of a few short years, an industry characterized by tight regulation (including export price and volume controls) and merchant pipelines became one that was anchored on wholesale transactions (including on export markets) at terms governed by individual buyers and sellers and open-access pipelines. This story has been told a number of times already, so there is no need to repeat it here.[2] For the purposes of this paper, however,

1 André Plourde is Professor, Department of Economics and Dean, Faculty of Public Affairs at Carleton University. Thank you to Joti Randhawa for research assistance.

2 For early discussions of the deregulation process directed at Canada's natural gas industry, see chapter 4 of John F. Helliwell et al, *Oil and Gas in Canada: The Effects of Domestic Policies and World Events* (Toronto: Canadian Tax Foundation, 1989) and National Energy Board (NEB), *Natural Gas Market Assessment* (Ottawa: Supply and Services Canada, October 1988). For a ten-year assessment, see NEB, *Natural Gas Market Assessment – Ten Years after Deregulation* (Calgary: National Energy Board, November 1996).

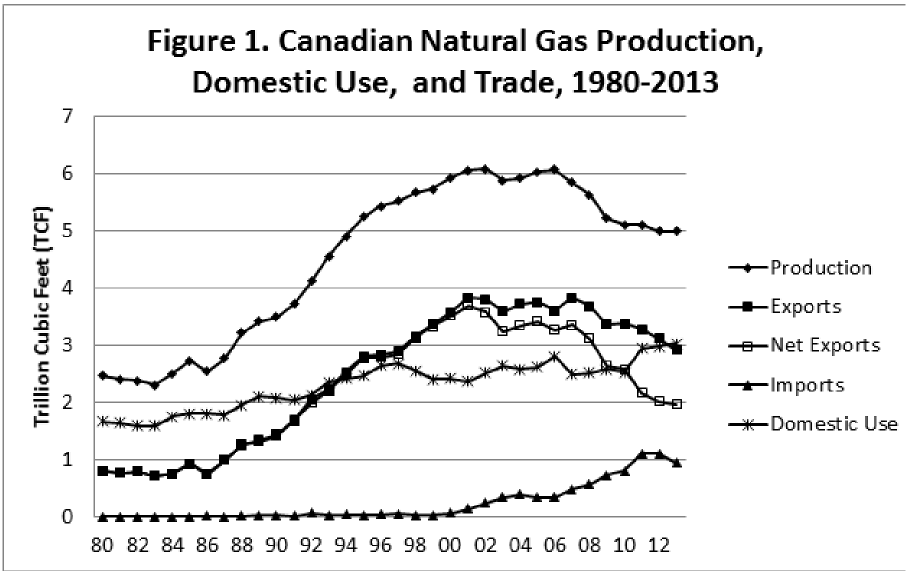
a key point to note is that this push toward a less regulated operating environment was followed by a period of phenomenal growth of natural gas production and exports.

As shown in Figure 1, production in 1986, for example, had been only slightly higher than that realized in 1980: 2.54 vs 2.46 trillion cubic feet (TCF), respectively.[3] And most of this gas was consumed in Canada. In every year from 1980 to 1986, domestic use (defined as production plus imports minus exports) accounted for more than two-thirds of total gas production in Canada.

In contrast, production grew by slightly more than 46 per cent (to 3.72 TCF) between 1986 and 1992 – an equal span of six years. Indeed, Canadian production of natural gas continued to grow strongly for another decade. By 2002, production reached 6.08 TCF, more than double that achieved in 1986. In the fifteen years that separate 1987 from 2002, output of natural gas from Canadian sources rose at an average rate of 5.4 per cent per year.

Over the same period, natural gas use in Canada also grew, but more slowly, rising from 1.78 TFC in 1987 to 2.51 TCF in 2002 – an average annual growth rate of 2.3 per cent. Growth in export volumes was even stronger than growth in production. From 1987 to 2002, exports of Canadian-produced natural gas to the United States – the sole export destination available to Canadian producers – rose from just below 1.0 to 3.80 TCF – an annual rate of increase of 9.4 per cent. The share of Canadian natural gas production consumed domestically fell rather consistently throughout this period, reaching 41.3 per cent in 2002. Figure 1 shows quite clearly the pronounced and sustained growth experienced in the output of Canada's natural gas industry during that period. It is also clear from Figure 1 that until 2000, natural gas imports into Canada were negligible. While there was then a slight increase in the next two years, import volumes remained quite small, reaching about 6 per cent of export volumes in 2002.

Figure 2 shows information on US natural gas consumption, production (dry gas production is the measure used here) and trade with Canada over the same 1980-2013 period as in



Sources: Statistics Canada, CANSIM; author's calculations for net exports and domestic use.

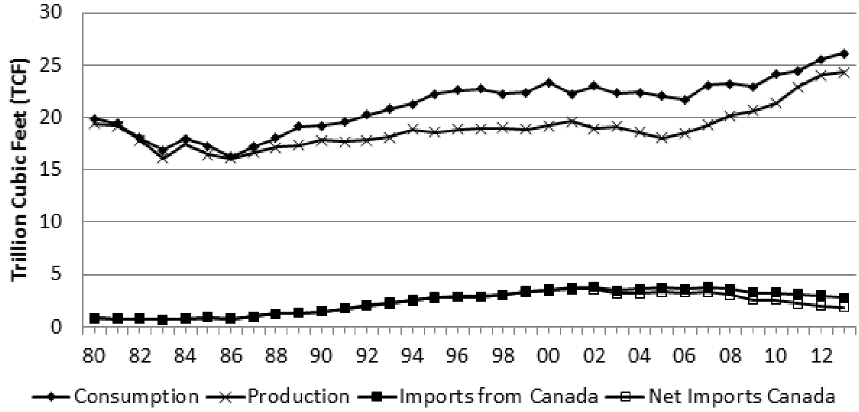
3 The production measure used here is deliveries of marketable gas. The primary source for both Canadian production and export data is Statistics Canada.

Figure 1.[4] The US natural gas industry underwent a process of deregulation similar in nature to what occurred in Canada. The US process, however, began earlier and lasted longer: it started in the late 1970s and was arguably not completed until the early 1990s. Nonetheless, to facilitate comparisons with developments in Canada, let us first focus on the 1980-1986 period. Overall, US natural gas production fell by approximately 17 per cent during those years, reaching its lowest value of 16.1 TCF in 1986. Imports from Canada – or anywhere else for that matter – did not play a big role in meeting US consumption between 1980 and 1986, accounting for some 4.6 per cent of domestic needs by the end of that period. In volumetric terms, imports from Canada were relatively flat: going from 0.80 TCF in 1980 to 0.74 TCF in 1986. Exports to Canada (or, again, anywhere else) were negligible during this period: net imports from Canada (i.e., gross US imports from Canada minus gross US exports to Canada) effectively equalled (gross) imports.[5] Between 1980 and 1986, the story of natural gas in the United States can thus be described as a period of contraction in production and consumption, and sluggishness in trade.

Things began to change in 1987 as growth in US consumption started to pick up and to outstrip that of domestic production. Between 1987 and 2002, US consumption grew by 33.7 per cent (from 17.2 to 23.0 TCF), while US production grew at less than half that rate, rising from 16.6 to 18.9 TCF, or 13.9 per cent, over the course of the same period. As Figure 1 indicates, imports from Canada filled this growing gap between US natural gas use and domestic production. In 2002, import volumes from Canada reached 3.79 TCF, the highest value for this period, and accounted for 16.5 per cent of total US natural gas consumption. US exports to Canada did grow over that period, but still amounted to only 0.19 TCF in 2002, only a small fraction of the trade flow going in the opposite direction.

The situation in 2002 can thus be characterized as follows. Canadian natural gas production has been rising rapidly over the previous fifteen years. Growth in exports

Figure 2. US Natural Gas Consumption, Production, Imports from Canada, 1980-2013



Sources: US Department of Energy, Energy Information Administration website; author's calculations for net imports from Canada.

4 US natural gas data used in this paper were obtained from the website maintained by the US Department of Energy's Energy Information Administration.
5 Note that in this paper when the term "imports" is used on its own, it is taken to mean "gross imports". The same applies to "exports".

to the United States has been even stronger as Canadian producers moved to fill the gap between US consumption and production. Overall, Canada has become an important source of natural gas for US consumers, while there continues to be very limited penetration of US-produced gas in Canada. Readers will have noted, of course, that the integration of Canadian and US natural gas markets became even more pronounced between 1987 and 2002, helped by the 1985 Halloween Accord in Canada, that deregulated natural gas markets in Canada, and with the coming into effect of the Canada-US Free Trade Agreement in 1989 and the North American Free Trade Agreement in 1994. As a result, any changes in natural gas trade patterns between Canada and the United States occurring after the mid-1990s are unlikely to be linked to trade policy changes in either country. Instead, market forces and thus the actions of market participants effectively determine flows of natural gas between these two countries. By 2002, Canada is thus an important, secure, and reliable source of natural gas supply for the United States, a state of affairs that had been solidified over the course of the previous fifteen or so years as a result of earlier policy actions and as the outcome of decisions by buyers and sellers of natural gas in the two countries.

And then the situation started to change again, as Figures 1 and 2 indicate. Production in both Canada and the United States was relatively flat for the ensuing five or so years, beginning in 2002. Exports of Canadian-produced natural gas to the United States also stayed relatively constant, but imports from the United States, though still relatively small, grew sharply (see Figure 1): between 2002 and 2007, Canadian imports of US-produced natural gas (mostly in Eastern Canada) more than doubled, reaching 0.48 TCF at the end of this period. During this period, growth in Canadian consumption was uneven, such that by 2007 domestic use was effectively the same as it had been in 2002 (2.48 vs. 2.51 TCF, respectively).

After this short "pause", the situation began to evolve in markedly different ways in the two countries. Production in the United States was on a sharp upward trend, growing by 26 per cent between 2007 and 2013. In contrast, Canadian production was edging downward, falling by some 14 per cent over the same period. By 2013, US natural gas production reached 24.3 TCF, a historical peak. Meanwhile, at 4.99 TCF, Canadian production in that year was almost exactly equal to the levels achieved 20 years earlier: in 1994, production of natural gas in Canada had been 4.90 TCF. As Figure 1 shows, Canadian consumption grew during this period, rising from 2.48 TCF in 2002 to 3.02 TCF in 2013 – in this last year of the time period under consideration, domestic use of natural gas in Canada exceeded exports to the United States for the first time. Canada also became much more reliant on the United States as a source of natural gas to meet domestic (here, Canadian) consumption needs: by 2013, volumes imported from the United States amounted to 31.7 per cent of Canadian natural gas use – that proportion had been equal to just 9.3 per cent in 2002.

All of a sudden US-produced natural gas was meeting consumption needs both domestically and in Canada. As an examination of Figure 2 reveals, US production grew faster than domestic consumption, meaning that the wedge between US consumption and production had been closing for the last half dozen years or so by the end of the period under consideration. Between 2007 and 2013, exports of US-produced natural gas to Canada almost exactly doubled, rising from 0.48 to 0.94 TCF. Perhaps not surprisingly, Canadian exports to the United States fell markedly during these six years, from 3.83 TCF in 2007 to 2.91 TCF in 2013 – a drop of almost 25 per cent. When brought together, these last two elements imply that the fall in <u>net</u> exports of natural gas from Canada was even more pronounced than that in (gross) exports: from 3.35 to 1.97 TCF – a reduction of about 40 per cent − over that time period. By 2013, net imports of natural gas from Canada met approximately 7.2 per cent of US natural gas consumption requirements, whereas the comparable measure for 2007 had been almost exactly double that value at 14.3 per cent.

By 2013, and the end of the period under consideration, the natural gas industry faced different realities in Canada and the United States. After a period of decrease, Canadian production had stabilized, but exports continued to fall, while imports from the United States were now a not insignificant part of Canada's energy consumption landscape (especially in Eastern Canada).

US natural gas production, on the other hand, had reached historical highs and had grown faster than domestic consumption, thus resulting in a sharply narrowed gap between US consumption and production. Imports volumes from Canada had fallen sharply which, combined with the growth in US exports to Canada, meant that once adjustments had been made for offsetting trade flows, Canadian-produced natural gas played a much smaller role in meeting US consumption needs. As was the case in 2002, Canada continued to be a secure and reliable source of natural gas supply for the United States in 2013. In contrast to the situation prevailing a dozen or so years earlier, however, in 2013 Canada was a much less important source of supply for US consumers of natural gas, in both relative and absolute terms: export volumes from Canada were lower and accounted for a smaller proportion of US consumption than had been the case in 2002.

Since the advent of natural gas deregulation in Canada in the mid-to-late-1980s, we can thus identify two distinct "periods" – and a brief transition between the two – in Canadian and US production and in natural gas trade between the two countries. From the mid-1980s to the turn of the century, Canadian production rose faster than that in the United States where the growth in consumption exceeded that of domestic production. Canadian producers moved in to fill this widening gap. Natural gas trade between the two countries was essentially a one-way flow, with volumes going from Canada to the United States. Canadian-produced natural gas met a rising proportion of US consumption needs.

The period from 2002 to 2006 can probably best be characterized as a transition phase for natural gas production and trade in North America. Natural gas production in both countries was relatively unchanged. Exports of Canadian-produced natural gas to the United States plateaued as well. Canadian import volumes of US-produced gas grew slightly, but remained relatively small. The stage was set, however, for pronounced changes in the structure of natural gas production and trade in North America.

Beginning in 2007 and lasting at least until the end of the period under consideration (i.e., 2013), Canadian and US production patterns differed sharply, with a rising trend characterizing the latter and falling production being observed in Canada. US natural gas production is rising faster than domestic consumption and Canadian exports to the United States are falling. US exports to Canada, while still smaller than trade flows in the other direction, are rising. Canadian-produced natural gas meets a shrinking proportion of US consumption needs. And US producers are selling growing volumes to Canadian buyers.

The overarching objective of this paper is to consider whether there is any evidence of a shift in perception in the United States of the role of Canadian production as a source of US natural gas supply. This section has highlighted the existence of two distinct periods in the patterns of natural gas production in Canada and the United States, and in trade flows between these two countries. The question of interest to us now is whether these changing activity patterns have led to reassessments of the long-term place occupied by Canadian natural gas in US markets. We turn to this task in the next section.

The Place of Natural Gas from Canada in the United States: An Assessment of EIA Projections

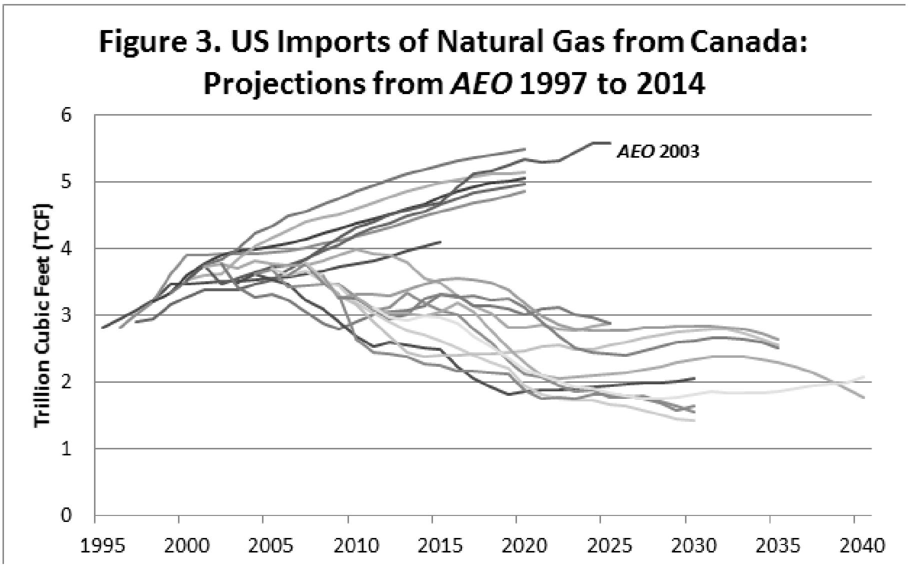
Every year, the US Energy Information Administration (EIA) produces an *Annual Energy Outlook* (AEO) that provides an overview of and commentary on expected future developments in US energy markets, including some of major trade patterns of relevance to the United States. Each edition of the AEO includes, among other things, long-term projections of key measures of production, consumption, and trade by energy source. US natural gas imports from and exports to Canada are both explicitly included as separate variables in these projections.

The EIA website contains detailed information about the long-term projections included in every edition of the AEO for the period 1997 to 2014. The "reference case" values of the projected series for US imports from Canada and for exports of US-produced natural gas to Canada were collected from the 18 editions of the AEO issued during the period identified above. To give the reader an impression of the information thereby assembled, Figure 3 provides a representation of the projections of US natural gas imports from Canada contained in each of the AEO editions included. For ease of presentation, only the projection from AEO 2003 is labelled in Figure 3, which allows, in turn, the use of that specific projection to describe what each of the series represents.

The series extracted from AEO 2003 contains values for each year extending from 2001 to 2025. The entries for the first two years (2001 and 2002) are the import volumes either observed or estimated for these two years. Projected values for the years 2003 to 2025 complete the series. Each individual projection (i.e., each "line" in Figure 3) is constructed in the same manner: actual "data" for the first few years and then projected values for all of the remaining years to the end of the period considered in the specific AEO edition from which the given series is taken.

Figure 4 illustrates the first important change in the view of the role of Canadian natural gas in the United States that emerges from the AEO projections. From 1997 to 2001, the projection included in each annual edition of the AEO called for rising gas imports from Canada over the time period considered. The 1997 projection, represented by the short "dash-dot" line in Figure 4, establishes this pattern. Each subsequent projection until that in 2001 (for ease of presentation, the only one of these shown in Figure 4) incorporate rising imports over the time period of the projection, and also calls for progressively larger volumes of imports in any given year of the projection period. Were these to have been included in Figure 4, the projections for the 1998, 1999, and 2000 editions of the AEO would lie between that from the 1997 edition and the one from 2001 (the dashed line at the top of Figure 4). According to AEO 2001, (net) US natural gas imports from Canada were to reach 5.5 TCF in 2020 and account for 16.7 per cent of domestic consumption in that year.[6] What is not evident from Figure 4 is that almost all US imports of natural gas are sourced in Canada in the projections incorporated in the AEO editions issued between 1997 and 2001.

As highlighted in the previous section, the period from 1997 to 2001 witnessed sustained growth in Canadian natural gas production and rising export volumes to the United States. The AEO editions produced during this time period thus translate this situation into a representation of Canada as an everlasting (at least until the end of the projection period) secure and reliable source of US gas imports.

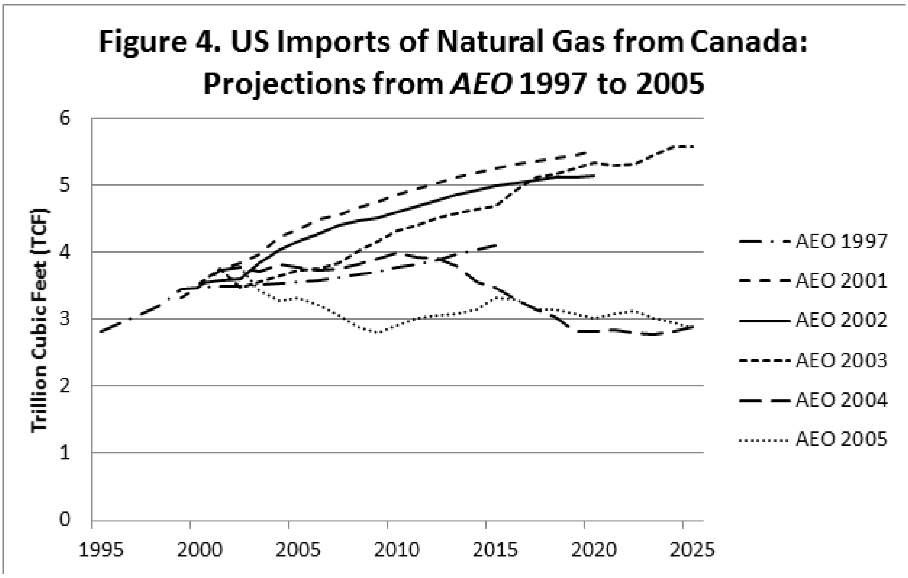


Sources: various editions (1997 to 2014) of Annual Energy Outlook (AEO), Energy Information Administration (EIA), US Department of Energy (US DoE); accessed electronically.

In AEO 2001, reference is made to additional imports coming from Western Canada and to production from Sable Island, off the coast of Nova Scotia, reaching US consumption markets as of the beginning of 2000. Mexico is seen as a destination for small volumes of US gas exports, while liquefied natural gas (LNG) is seen as growing in importance over time, but "is not expected to grow beyond a regionally significant source of U.S. supply…"[7] Until 2001, the "story" of US natural gas imports in the AEO projections remains essentially told by exports from Canada.

Things begin to change in 2002. The US supply picture improves in the 2002 edition of the AEO and the growing importance, especially in the projection period, of "tight sands, shale, and coal bed methane" as sources of US natural gas supply is specifically highlighted. This is accompanied by a slightly more expansive view of the role of LNG in meeting future US consumption needs.[8] These two factors – but principally the more optimistic view of US gas production potential – overlay a situation where imports from Canada decline slightly in importance in the overall representation of developments on US natural gas markets, as the solid line in Figure 4 indicates.

The 2003 projection (the dashed line extending to 2025 in Figure 4) brings a few additional factors into consideration. Here, the unconventional sources of production identified above continue to play an increasingly important role in the overall natural gas supply picture in the United States, but AEO 2003 is much less optimistic about the prospects for post-2015 conventional production in the lower 48 states than had been the case one year earlier. The projected decrease in overall US production that results is assumed to be met by increased imports from Canada and by growing LNG imports.[9]



Sources: 1997 and 2001 to 2005 editions of AEO, EIA, US DoE; accessed electronically.

6 Sources for these projected values are Energy Information Administration (EIA) *Supplement Tables to the AEO 2001* (accessed electronically) at Table 82 and Annual Energy Outlook 2001, With Projections to 2020 (Washington, DC: US Department of Energy, December 2000) at 83, respectively.
7 *Ibid*.
8 EIA, *Annual Energy Outlook 2002*, *With Projections to 2020* (Washington, DC: US Department of Energy, December 2001) at 82.
9 EIA, *Annual Energy Outlook 2003*, *With Projections to 2025* (Washington, DC: US Department of Energy, January 2003) at 76.

As represented in AEO 2003, Canada remains an important part of the supply picture of natural gas in the United States, but this position seems increasingly challenged by US unconventional production and by imports in the form of LNG.

The representation of the place of Canadian natural gas in the Unites States changes dramatically in AEO 2004, as Figure 4 shows. This is not driven by changes in the perception of the role to be played by US domestic production. Instead, the picture presented in AEO 2004 is one of decreasing production capacity in Canada, especially in the Western Sedimentary Basin, and of the absence of significant new discoveries offshore Canada's East Coast. Imports from Canada are projected to peak in 2010 and then to decrease gradually to 2025 and the end of the projection period, this despite the continued inclusion in the projection of a Mackenzie Valley pipeline, assumed to bring volumes of natural gas from Canada's North to US markets beginning in 2009. In other words, there has been a downward reassessment of Canada's overall potential as a source of natural gas supply for US consumers and, as far as the authors of AEO 2004 are concerned, LNG imports from other countries will step into the breach, with volumes projected to rise from 0.2 TCF in 2002, to 4.8 TCF in 2025.[10] AEO 2005 takes this change in perception of Canada as a source of natural gas for the United States further: imports of Canadian-produced gas are seen as having peaked in 2003, prior to the beginning of the projection period (dotted line extending to 2025 in Figure 4). LNG imports, on the other hand, are projected to ramp up faster and to reach higher levels by the end of the forecast period: imports of 6.4 TCF in 2025, compared to a projection of 4.8 TCF put forward only one year earlier in AEO 2004.[11]

As noted in the previous section, Canadian natural gas production plateaued and US production fell slightly between 2002 and 2007. Within a few years of the beginning of this period, the projections incorporated into the AEO editions reflected this changing reality of natural gas production in the two countries. This resulted in a reassessment of the role that Canadian-produced gas was expected to play in the US marketplace: imports from Canada were no longer seen as being sufficiently large to close the gap between US consumption and production. The remaining gap would be closed by LNG imports, which eventually acquired a much greater importance in meeting US consumption in AEO projections. This is most starkly revealed by a comparison of the projection in AEO 2003 and that in AEO 2004. In the course of a single year, the assessment of future Canadian natural gas production capacity included in AEO projections worsened significantly and LNG imports were expected to begin to play part of the role that had thus far been reserved to production from Canada in projections of US natural gas supply-demand balances.

The next transitions in the views expressed in the AEO about the prospective role of Canadian-produced in the United States are less starkly defined, though no less important, than the one described above. Figure 5 shows projections from a number of AEO editions issued between 2005 and 2014. These specific projections were selected to document the changes in perspective that occurred, while facilitating presentation (and allowing for Figure 5 to be relatively easy to interpret).

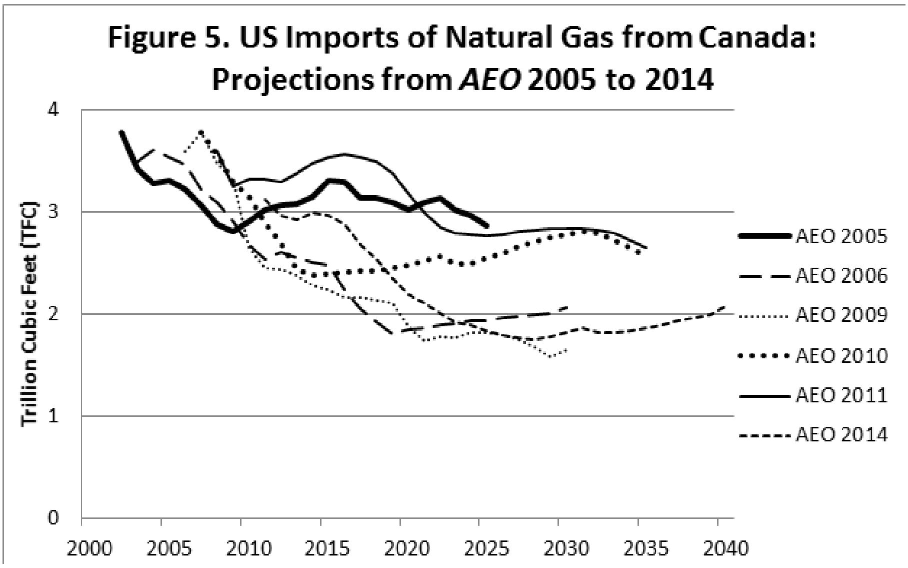
Our starting point is the last projection included in Figure 4, namely that from AEO 2005 (now the short, thick line in Figure 5). In the course of the next four years, successive AEO editions featured projections that incorporated a trend of decreasing US reliance on imports of natural gas from Canada. Basically, the entire projected time profile of imports (except for the first few years of the projection period) drifted downward year after year, eventually reaching that included in AEO 2009 and represented by the dotted line extending to 2030 in Figure 5. Three key factors sustain these changing views. First, successive projections present an increasingly optimistic view of US production: from an expected decline over the projection period in AEO 2006, to a long-term flat production profile in AEO 2007, to one characterized by modest growth (AEO 2008), and then solid growth (AEO 2009). All of

10 EIA, *Annual Energy Outlook 2004, With Projections to 2025* (Washington, DC: US Department of Energy, January 2004) at 91.
11 EIA, *Annual Energy Outlook 2005, With Projections to 2025* (Washington, DC: US Department of Energy, February 2005) at 96.

these changes are directly linked to an upward revision in the potential of the unconventional (and especially shale) resource base in the United States.

Second, whenever higher import volumes are needed to close the projected gap between US natural gas production and consumption, LNG is assumed to play that role. Sharp increases in LNG imports, typically beginning a few years into the projection period, characterize the projections in successive AEO editions issued during most of this period. In AEO 2008, for example, LNG imports into the United States are projected to be twice the size of the imported volumes of Canadian-produced natural gas: 2.8 vs 1.4 TCF, respectively, in 2030.[12] There is also an interaction between the two factors identified above. The marked increase in expected US production incorporated into AEO 2009 is accompanied by a downward re-assessment of the role of LNG in meeting future US natural gas demand: projected LNG imports in 2030 are now below 0.9 TCF,[13] less than one-third the level projected only one year earlier in AEO 2008. Faster growth in US production is expected to displace increasingly large volumes of imported LNG.

A third factor that underlies this picture of a growing US natural gas self-reliance is the projected evolution of Canadian natural gas production and its disposition. Canada's production capacity from conventional sources – mainly the Western Sedimentary Basin – is seen by the AEO authors as being in a situation of long-term decline. Growth prospects for Canada's Arctic region and from unconventional sources are projected to be too modest for production from these sources to offset fully the expected decline in conventional production. To make matters worse, the Mackenzie Valley pipeline that had been featured in the AEO for many years was taken out of the projection in AEO 2008: construction of the pipeline was assumed to be pushed back beyond the end of the projection period (a situation that has continued to prevail in subsequent editions of the AEO, including the most recent one).[14] AEO 2009 includes a



Sources: 2005, 2006, 2009-2011, 2014 editions of AEO, EIA, US DoE; accessed electronically.

12 EIA, *Annual Energy Outlook 2008, With Projections to 2030* (Washington, DC: US Department of Energy, June 2008) at 78 [*AEO 2008*] for LNG imports; EIA, *Supplemental Tables to the Annual Energy Outlook 2008* (accessed electronically) at Table 106 for imports from Canada.
13 EIA, *Annual Energy Outlook 2009, With Projections to 2030* (Washington, DC: US Department of Energy: March 2009) at 78 [*AEO 2009*].
14 *AEO 2008*, *supra* note 12.

more optimistic view of Canada's production potential from unconventional sources, but now domestic demand patterns are seen as curbing the country's export potential: "… Canada's unconventional production does not increase rapidly enough to keep up with domestic demand growth while maintaining current export levels."[15] As the dotted line extending to 2030 in Figure 5 reminds us, even though the assumed prospects for LNG imports into the United States dimmed considerably from AEO 2008 to AEO 2009, this was not sufficient to bring about a meaningful re-appraisal of the overall role of Canadian-produced natural gas in the US marketplace. Instead, increased US production is projected to make up for any decrease in LNG import volumes.

In AEO 2010, shale gas is presented as "… the largest contributor to the growth in [US] production."[16] Despite this buoyant portrayal of future production prospects in the United States, imports from Canada were projected to rebound somewhat in comparison to the picture presented in AEO 2009. As the dotted line extending to 2035 in Figure 5 indicates, the expected increase in import volumes from Canada is particularly noticeable after 2020. What is not obvious from Figure 5 is that this increase was accompanied by a corresponding fall in projected LNG imports. In the longer term, therefore, AEO 2010 still portrays Canadian production as an important source of supply from which to meet changes in the long-term prospects for US LNG trade.

The first few years of the projection period in AEO 2011 are characterized by an upward "blip" in import volumes from Canada (see the solid line extending to 2035 in Figure 5). The accompanying text reveals that the AEO authors see these higher volumes as being linked to stronger expected US consumption and improved short-term production prospects from unconventional sources in Canada. As the projection horizon is extended, however, Canadian imports are assumed to return to the levels characteristic of AEO 2009.

From then on, successive editions of the AEO depict Canadian-produced natural gas as playing a smaller and smaller role in meeting US demand: the entire profile of projected US imports of natural gas from Canada drifts downward, eventually reaching in AEO 2014 that represented by the dashed line extending to 2040 in Figure 5. LNG imports don't fare any better: these fall even further in the AEO 2011 projection and effectively disappear in AEO 2012. In contrast, US production is portrayed as characterized by strong growth, both from one AEO edition to another (i.e., upward shifts of the projected production profile) and within each individual projection (i.e., production growing over time). The key driver of these improved prospects is the strong, sustained growth projected for US shale gas production. Indeed, in AEO 2012, the United States is portrayed as a net exporter of natural gas, beginning in 2020. Subsequent AEO editions have painted an even more aggressive picture of the supply-demand balance for natural gas in the United States: in AEO 2014, net exporter status is projected to be achieved in 2018 and (net) LNG exports reach 3.5 TCF by 2030.[17] This, of course, marks a dramatic reversal in the perceived place of LNG in US natural gas trade from that projected to occur as recently as in AEO 2008.

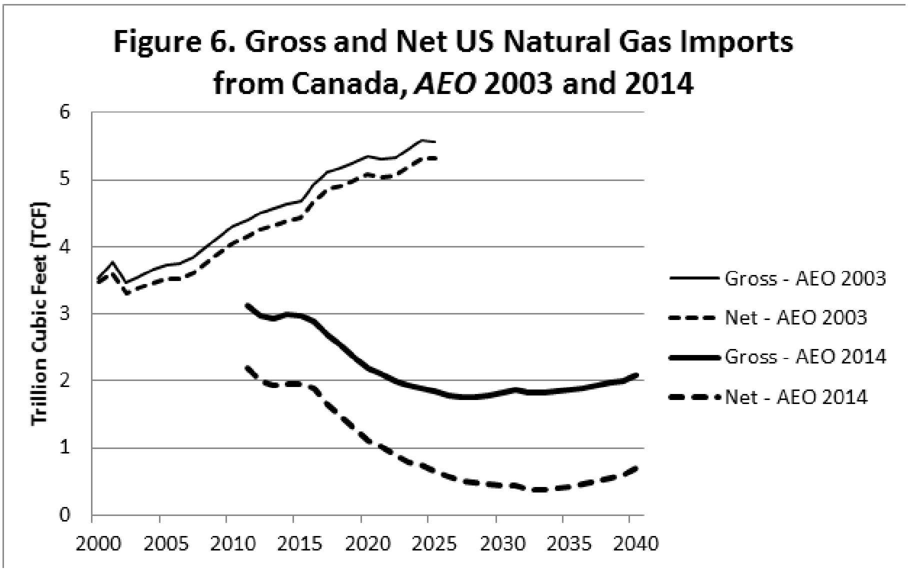
Perhaps the most telling description of the "new" perceived role of Canadian-produced natural gas in the United States can be found in AEO 2013: "[e]ven as overall consumption exceeds supply in the United States, some natural gas imports from Canada continue, based on *regional supply and demand conditions*"[emphasis added].[18] The reader will recall that, as noted earlier, quite similar words were used in AEO 2001 to describe the projected role of LNG imports in the overall picture of natural gas in the United States.

In AEO 2014, imports from Canada are expected to account for approximately 7.2 per cent of US natural gas consumption in AEO 2014 by the end of the projection period in 2040, namely 2.07 of 28.45 TCF.[19] Since this arguably still represents a reasonably large proportion of US natural gas use, in what sense

15 *AEO 2009*, *supra* note 13.
16 EIA, *Annual Energy Outlook 2010*, *With Projections to 2035* (Washington, DC: US Department of Energy, May 2010) at 72.
17 EIA, *Annual Energy Outlook 2014*, *With Projections to 2040* (Washington, DC: US Department of Energy, April 2014) at MT-22, Table 134 [*AEO 2014*].
18 EIA, *Annual Energy Outlook 2013*, *With Projections to 2040* (Washington, DC: US Department of Energy, April 2013) at 79.
19 *AEO 2014*, *supra* note 17, Table 134 for imports from Canada and Table 135 for US consumption.

can it be seen to indicate a limited role ("based on regional supply and demand conditions") for Canadian-produced natural gas in the United States? Figure 6 sheds some light on this matter. The two lines at the top left of that Figure represent the projections from AEO 2003 for gross and net US imports of natural gas from Canada, where net US imports are defined as gross US imports from Canada minus gross US exports to Canada. The two lines at the bottom right of the Figure represent the same concepts, with projected values taken from the 2014 edition of the AEO. A key difference should now be clear: projections of the size of US export volumes to Canada (and mainly to Eastern Canada) have increased markedly in the eleven years that separate these two AEO editions. In all editions of the AEO issued between 1997 and 2003, projected US exports of natural gas to Canada are essentially negligible. With AEO 2004, however, the expectations are for volumes of natural gas exported from the United States to Canada to grow, both within a given projection period and across AEO editions – a trend that becomes increasingly pronounced as the release date of individual AEOs get closer to the present day.

In the projections incorporated into AEO 2003, never do US exports to Canada reach 0.3 TCF and never do these exceed 6.25 per cent of the volumes of natural gas expected to flow in the opposite direction.[20] As far as AEO 2014 is concerned, however, US export volumes to Canada are expected to vary between 0.99 and 1.45 TCF over the projection period.[21] In relative terms, this means that US export volumes to Canada never fall below 33 per cent of the volumes of natural gas projected to be imported into the United States from Canada, and this proportion exceeds 65 per cent (or ten times the highest value observed in the AEO 2003 projection) in more than one-half of the years in the projection period. As Figure 6 shows, net imports from Canada are thus not expected to exceed 0.9 TCF between 2022 and 2040. Indeed, the AEO 2014 projection for net US imports of natural gas from Canada in 2040 (the last year of the projection period) is 0.71 TCF, or 2.5 per cent of US consumption in that year.[22] In this context, Canadian-produced natural gas can indeed be characterized as playing a limited role in the US marketplace, one that is quite likely focused on a few specific



Sources: gross US imports - 2003 and 2014 editions of AEO, EIA, US DoE; accessed electronically; net imports – author's calculations (using gross US exports to Canada, drawn from same sources as above).

20 EIA, *Supplement Tables to the Annual Energy Outlook 2003* (accessed electronically) at Table 104.
21 *AEO 2014*, *supra* note 17.
22 *Ibid*.

regions of that country.

Reflections on Implications for Canada and for North American Gas Markets

The picture of the future North American natural gas market that emerges from these successive EIA projections is one of a continued integrated Canada-US marketplace, but one where the nature of the integration changes from an almost exclusively one-way flow of production from Canada to the United States, to one of rising (net) Canadian imports of US-produced natural gas. It seems reasonable to conclude that in and of itself this change should not affect natural gas pricing dynamics in the two countries. If this were to be the only change to be considered then production from shale and tight sands formations in Canada would continue to respond to made-in-North-America natural gas prices.

But what about the potential for significant volumes of LNG exports identified in the EIA projections and resulting from proposed export projects in Canada (especially British Columbia)? The expected destinations for these export volumes are mainly consumption markets in Asia, where delivered prices of natural gas have tended to exceed – sometimes by wide margins – those in North America. In 2013, for example, delivered prices of natural gas in Japan averaged $(US) 16.17 per million BTU, while the average price at Henry Hub equaled $(US) 3.71.[23] Even if the volumes consumed are much smaller than in North America,[24] it seems clear that North American natural gas production destined for export markets in Asia would put upward pressure on prices in North America, at least in the short to medium term, irrespective of whether the LNG exports were from Canada or the United States. The commercial logic of these prospective higher prices no doubt fuels, at least in part, current proposals for LNG export projects in these two countries.

A critical issue then becomes the extent of price arbitrage that could be expected to occur if these two previously disconnected natural gas "islands" (Asia and North America) begin to experience some degree of market integration through LNG trade. At the outset, it should be clear that the extent of upward price pressure in North America would depend on the price responsiveness of demand in target export markets. The less price responsive (i.e., the more inelastic) the demand for natural gas in these markets, the less intense will be the pressure for upward price movement in North America. In such a case, one would expect this pressure to be largely dissipated as a result of price decreases in the target export markets, all else held equal.

An additional complication relates to the role of liquefaction capacity in the exporting countries. To the extent that this capacity is scarce relative to the LNG export market potential, the higher delivered prices in Asia are likely to result, at least for some time, in opportunities for higher-than-normal returns on liquefaction capacity investments as opposed to higher natural gas prices in North America. This creates policy and regulatory challenges in Canada and the United States in terms of whether and how to address the possibility of higher-than-normal returns on energy infrastructure investments. More generally, the extent of liquefaction capacity constraints (or, equivalently, of constraints on LNG shipping capacity) and its evolution over time will clearly affect the extent and intensity of upward pressure on natural gas prices in North America, which in turn will play a role determining the prospects for the development of unconventional natural gas deposits in Canada.

The emergence of a more balanced natural gas trade pattern between Canada and the United States provides an interesting vantage point from which to consider some proposed Canadian energy infrastructure projects, especially LNG export terminals in British Columbia and Energy East, the conversion (and extension) by TransCanada of one of its West-to-East natural gas pipelines into an oil line. Broadly speaking, natural gas production in British Columbia (or Western Canada, more generally) from newly developed (and mostly

23 This price information is from *BP Statistical Review of World Energy 2014* (London, UK: British Petroleum, June 2014) at 23, online: BP <http://www.bp.com/content/dam/bp/pdf/Energy-economics/statistical-review-2014/BP-statistical-review-of-world-energy-2014-full-report.pdf>.

24 For example, according to *ibid* at 27, total consumption of natural gas in Canada and the United States reached 29.7 TCF in 2013. Comparable values for Japan and South Korea – key existing target markets – were 4.1 and 1.9 TCF, respectively; at 5.7 TCF, total consumption in China was slightly smaller than that in Japan and South Korea combined. Consumption in these three countries combined was slightly less than 40% of the Canada-US total in 2013.

unconventional) reserves could potentially reach two distinct markets: Asia and Eastern Canada. The first of these opportunities is what motivates the proposals for LNG export terminals located on Canada's West Coast. As noted earlier, delivered prices in Asia are much higher than in North America, and so there is an incentive, at least in the short to medium term, to attempt to translate these higher prices in Asia into positive returns on energy investments in Canada.

A second option would be to use the existing inter-provincial pipeline infrastructure (and any required additions thereto) to enable BC-produced natural gas to displace, mostly in Eastern Canada, projected volumes of imports from the United States. The Energy East project then comes to the fore: how would the conversion of a natural gas transmission pipeline to other purposes affect the business case for deliveries to Eastern Canada of natural gas produced in British Columbia? To the extent that the existing infrastructure (minus the line at the heart of Energy East) could accommodate the incremental volumes without any capacity constraints, then the proposed conversion could be expected to have little to no effect on the business case for shipments of BC-produced gas to Eastern Canada. The situation would be different, of course, if the proposed conversion led to the creation of natural gas transmission capacity constraints in Canada. The regulatory process assessing the proposed pipeline conversion would arguably be an appropriate venue in which to consider this issue.

Overall, Canadian sellers and shippers will need to choose how to dispose of this new production. The existing policy approach in Canada of reliance on market forces would give rise to a situation where buyers, sellers and shippers of this new production would assess the risks and the potential benefits and costs of alternative courses of action, and through their actions determine if one, the other, or both of the options identified above are worthwhile paths to follow. With this kind of approach, regulatory intervention would only be used to address specific issues that would impede market operations, such as the potential creation of transformation and transportation capacity bottlenecks. To the extent that policy-makers were to elect, as a matter of policy, to favour one option over another, they run the risk that such action will lead to a lower realized value of the natural gas reserves whose development, production, and disposition are linked to the market opportunities considered in the last few paragraphs.

Overview and Summary

An assessment of specific aspects of comprehensive projections of the evolution of US natural gas markets produced by the Energy Information Administration (EIA), an agency of the US Department of Energy led to the identification of marked changes in the role of Canadian-produced natural gas in the United States, as reported in the editions of the EIA's *Annual Energy Outlook* (AEO) released between 1997 and 2014.

There was a sharp break in the perceptions of the role expected to be played by US imports of natural gas from Canada between the 2003 edition of the AEO and that issued in 2004. Successive AEO editions released between 1997 and 2003 each incorporated an expectation of a growing role for Canadian-produced natural gas over the course of the projection period and of an expanded presence in the US marketplace across projections. Not only did AEO 2004 incorporate a sharp downward shift in the time path of projected gas imports from Canada, but it was also characterized by a change in the "slope" of this time path: no longer were imports from Canada perceived as growing over time; rather, import volumes were expected to fall as the projection horizon lengthened. Changes in the anticipated long-term productive capacity of the Canadian resource base were at the heart of this re-assessment. And, as the review of key activity measures undertaken earlier in the paper indicates, the timing of this re-assessment corresponds closely to a change in the pattern of natural gas production in Canada: from a period of sustained growth, to one where output plateaued.

This change in the perceived role of Canadian-produced gas in the US marketplace was reinforced in subsequent AEO editions, at the same time as actual Canadian natural gas production began to fall. Basically, a sustained downward drift in the projected time path of US imports of natural gas from Canada was incorporated into issues of the AEO released between 2005 and 2014. There was a re-assessment of the perceived role of Canadian gas in the United States in AEO 2010 and 2011, where slight upward shifts in the projected time path of US imports from Canada were observed. But this re-assessment proved short-lived and the downward drift of the time path of projected imports began again in AEO 2012. Initially, sharp increases in LNG imports were expected to compensate for the falling natural gas volumes projected to be imported from Canada. Eventually, however, sustained pronounced increases in the production of shale gas in the United States were expected to reduce sharply the need to draw from foreign sources of natural gas to meet US consumption needs.

In the 2014 edition of the AEO, these increases in US shale gas production are expected to be strong enough to transform the United States into a net exporter of natural gas before 2020. It is perhaps not surprising then that the re-assessment of the role of Canadian gas is even more starkly defined when both directions of natural gas trade flows between the two countries are considered, and net US imports are tracked. By the end of the projection period in 2040, (Eastern) Canada becomes a destination for US exports of natural gas and net US imports from Canada amount to less than 2.5 per cent of total projected US consumption. Canada's role is perceived as that of a player on some regional markets in the United States, in sharp contrast to the situation that prevailed in editions of the AEO issued in the late 1990s and early 2000s. The "glory days" of Canadian-produced natural gas in the US marketplace thus appear to be behind us, never to return (at least, not to return before well after 2040!), if the projections incorporated into recent AEO editions are to be believed.

Since projected increases in US production are expected to lead to significant export volumes via pipeline to Canada and in the form of LNG to more distant (especially Asian) markets, possible implications of these developments were also examined. The potential for natural gas price increases in North America in the short to medium term was seen as conditional on a number of other factors, including liquefaction capacity constraints in Canada and the United States. An assessment of recent EIA projections suggests that production from newly tapped natural gas deposits in Western Canada could result not only in LNG exports from British Columbia, but also in the displacement of some volumes of US-produced gas that would otherwise be imported into Eastern Canada. To the extent that policy intervention or the design of the relevant regulatory regime expressly favours one over the other of these two options, then a possible consequence is a reduction in the realized value of these newly tapped natural gas deposits. Transmission capacity constraints could also affect the business case for pipeline transmission from British Columbia to Eastern Canada. It would seem appropriate to consider these factors and their possible implications in the regulatory process dealing with TransCanada's proposed Energy East project.

In the end, a changing role for Canadian natural gas on US markets may well create opportunities for Canadian producers (and consumers) to explore new possibilities for the disposition of higher domestic production volumes that may be realized in the future. An assessment of the expected place of Canadian gas in the United States has led to reflections on new market opportunities outside of that country. ■

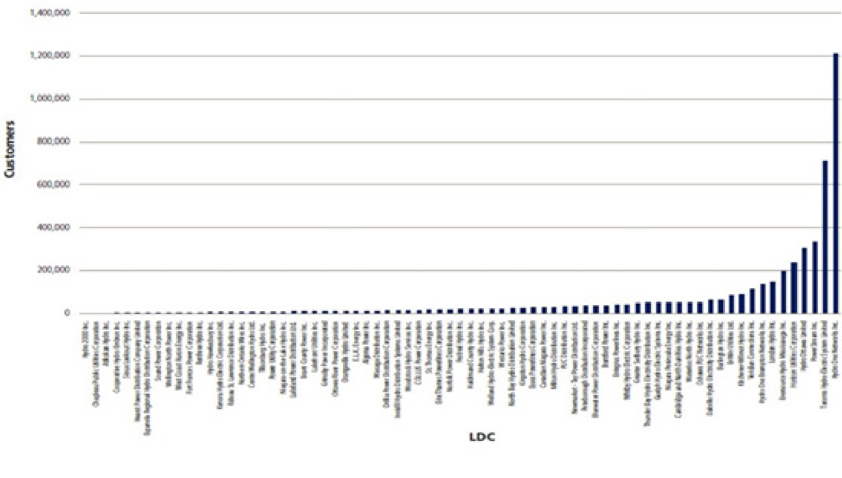
IMPROVING ONTARIO'S ENERGY INFRASTRUCTURE: REDUCING THE COST OF LDCS

*Duncan Melville, CFA**

As of December 2013 there were 73 local electricity distribution companies ["LDCs"] under the regulation of the Ontario Energy Board ["OEB"]. The size of these distribution companies varies widely, from Hydro 2000, with only 1,220 customers and 21km of network in the small town of Alfred, to Hydro One Networks, with 1.2 million customers and 120,000km of network across the province. While relative to other provinces this remains a large number, the current position is a significant reduction from the almost 400 electricity utilities existing in 1923.[1] Most LDC consolidations took place in the late 1990s when a temporary lifting of a provincial transfer tax encouraged municipalities to divest their distribution assets to Hydro One. Since then consolidations have been slower and taken place on the basis of voluntary reorganizations among neighbouring municipalities, for example Powerstream, Veridian Connections, Horizon Utilities, and more recently, Lakeland Power *(See Figure 1).*

The 2012 "Drummond Report" highlighted the potential cost savings of further consolidation of Ontario's LDCs.[3] Since then discussion about LDCs has focused on how to undertake such consolidation, with recommendations including

Figure 1 – Ontario LDCs by Customer Number[2]



* Duncan Melville, CFA is a JD candidate at the University of Toronto. He is also a CFA Charterholder.

1 Murray Elston, Floyd Laughren and David McFadden, *The Report of the Ontario Distribution Sector Review Panel* (December 2012) at 5.
2 *Ibid* at 7.
3 Donald Drummond, *Commission on the Reform of Ontario's Public Services* (2012) at 331 [*Drummond Report*], online: Ontario Ministry of Finance < http://www.fin.gov.on.ca/en/reformcommission/>.

a loosening of the transfer tax system to encourage consolidation similar to the late 1990s,[4] as well as forced consolidation into regional distributors with a minimum of 400,000 customers.[5] In addition, more recently, the Premier's Advisory Council on Government Assets released a report (hereby known as the "Ed Clark Report") recommending the consolidation of Hydro One Brampton with other GTHA[6] distributors to produce a entity comparable in size to Toronto Hydro.[7] The hope of the Advisory Council was that such a merger would trigger additional consolidation eventually resulting in only three to four provincial electricity distribution companies.[8]

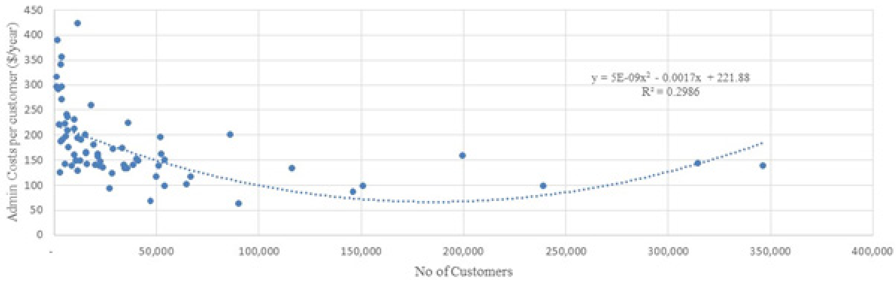
This paper generally supports the consolidation of Ontario's electricity LDCs but proposes an alternative method to the reorganization. The analysis centres on two issues: first, whether larger LDCs are in fact cheaper[9] and second, whether private investment in LDCs has led to cost reductions. Based on the results of these examinations consolidating Ontario's smallest LDCs into larger "regional" distribution companies ["RDCs"], and operating these RDCs as private concessions, similar to other provincial services like driver examinations,[10] is believed to lead to the greatest possible savings. The author also believes this solution addresses the confluence of politics and industry forces defining energy regulation and overcomes the historical view that competition in this sector was impossible.

Question 1: Are Larger LDCs Cheaper?

There are many logically explainable cost differences between Ontario's LDCs. For instance, LDCs covering a sparsely populated area will have higher per person maintenance costs given greater distances travelled by crew and potentially harsher weather conditions. Therefore, to draw meaningful conclusions about the relative cost efficiencies of LDCs it is better to focus on administrative costs.[11] Normatively, in an age of mobile communications, administrative costs should be more closely aligned between LDCs of differing size than O&M costs (See Figure 2).

Plotting Ontario's LDCs on the basis of

Figure 2 – Administrative Costs per Customer by Total No of Customers (2013)[12]



Note: Hydro One Networks and Toronto Hydro are excluded, they are significantly larger so obscure trends.

---

4 Stephen Fyfe, Mark Garner and George Vegh, "Mergers by Choice Not Edict: Reforming Ontario's Electricity Distribution Policy", CD Howe Institute, Commentary No 376 (March 2013) at 21[*Fyfe*].

5 Murray Elston, Floyd Laughren and David McFadden, *The Report of the Ontario Distribution Sector Review Panel* (December 2012) at 39 [*ODSRP Report*].

6 Greater Toronto and Hamilton Area.

7 Ed Clark et al, "Striking the Right Balance: Improving Performance and Unlocking Value in the Electricity Sector in Ontario", *Premier's Advisory Council on Government Assets* (April 2015) at 13 [*Ed Clark Report*].

8 *Ibid* at 12.

9 This issue will be explored in less detail than the second question given the extensive literature on the subject, for example, see notes 4 - 5.

10 *Driver Examination Services Project Agreement*, online: Infrastructure Ontario <http://www.infrastructureontario.ca/templates/projects.aspx?id=2147488447&langtype=1033>.

11 Administrative costs comprise 'billing and collection', 'community relations', 'administrative and general expenses' and 'advertising expenses' as disclosed in the 2013 Benchmarking Update Report of LDCs.

12 *2013 Benchmarking Update Calculations,* Ontario Energy Board (August 2014), online: <http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Renewed+Regulatory+Framework/Measuring+Performance+of+Electricity+Distributors>.

administrative costs per customer in comparison to total customer numbers illustrates a visible downward trend between LDCs with less than 25,000 customers to those with approximately 150,000 customers (see *Figure 2*). These results are consistent with earlier analyses which similarly showed a decreasing trend in costs, albeit with a subsequent increase in the average costs for the largest utilities.[13] It is therefore possible that an inflection point exists and consolidation of the province's larger LDCs may not lead to additional cost savings. However, consolidation of Ontario's smallest LDCs (those with less than 25,000 customers) could yield annual administrative cost savings of over $40 million, given administrative costs comprise 40-60 per cent of such LDCs' budgets.

Recommendation 1: Consolidate the Smallest LDCs Into Larger RDCs

While further analysis into the optimal size and number of RDCs would be preferred, it is unlikely the minimum threshold of 400,000 customers recommended by the Ontario Distribution Sector Review Panel's 2012 report is required (see *Figure 2*).[14] In addition, the recommendation in the Ed Clark Report for only three or four LDCs may also be sub-optimal. In northern and rural areas it is possible that 150,000 to 200,000 customers would be most cost effective solution, any bigger and potential diseconomies of scale may emerge.[15] A greater number of RDCs than the 3 or 4 recommended by the Ed Clark Report will also help foster competition in the concession market (see Recommendation 2), allowing smaller operators to enter the bidding process and drive down costs between RDCs.

Question 2: Does Private Sector Involvement in LDCs Lead to Lower Costs?

Numerous scholars have broadcasted the potential cost savings of outsourcing the operations of public infrastructure to the private sector. Jose Gomez-Ibanez lists such savings as being in the range of 20-40 per cent.[16] Sally Hunt also favours private involvement in the electricity sector, citing the fact no country has returned to regulated pricing since introducing competition.[17] In Canada, the view that private sector involvement in public infrastructure is cheaper is more mixed. The province of Ontario enjoys a lower cost of capital than any Canadian corporation so can develop more cost-effective solutions,[18] and there have been mixed experiences with private operators of public services.[19] According to the Auditor General of Ontario however, O&M costs over the 74 AFP[20] projects currently in operation were 27 per cent cheaper than the public sector estimate.[21]

In Ontario, while the majority of regulated LDCs are provincially, or municipally, owned, seven have, within the last 15 years, received private investment (see *Figure 3*). At less than 10 per cent of the province's LDCs this is admittedly a small sample but does nonetheless provide an indication of the potential impacts of private involvement.

Of the seven 'privatized' LDCs only Algoma Power and Canadian Niagara are wholly-owned and privately operated so provide the strongest indication of the potential impact of privatizing LDC operations. Enersource is minority owned by Borealis, a division of the pension fund OMERS. Given Borealis' lack of operational expertise this is less an example of privatized operations and rather an instance of private investment in a publically operated company. The analytical value of the remaining four LDCs lies somewhere in between. This middle position results from the municipality retaining primary operating responsibility, while seeking to partner with private operators to deliver operational efficiencies and improvements.[22]

13 *Fyfe, supra* note 4 at 8.
14 *ODSRP Report,supra* note 5 at 29.
15 *Fyfe, supra* note 4 at 4.
16 Jose Gomez-Ibanez, *Regulating Infrastructure: Monopoly, Contracts and Discretion* (Cambridge: Harvard University Press, 2003) at 185 [*Gomez-Ibanez]*.
17 Sally Hunt, *Making Competition Work in Electricity*, (New York: John Wiley & Sons, 2002) at 5 [*Hunt*].
18 Office of the Auditor General of Ontario, *2014 Annual Report of the Office of the Auditor General of Ontario* at 197 & 208 [*2014 Auditor General Report*].
19 Ontario Chamber of Commerce, "Public Sector Problems, Private Sector Solutions" (2013), at 11, online: OCC <http://www.occ.ca/Publications/Public-Sector-Problems-Private-Sector-Solutions_Electronic.pdf>.
20 "AFP" means 'alternative financing and procurement'.
21 *2014 Auditor General Report, supra* note 18 at 199.
22 "Grimsby Power a Step Closer to Fortis Deal", *Niagara This Week* (March 27, 2009), online: <http://www.

Using data from the OEB, the costs of each ‘privatized’ LDC were analyzed using three metrics:

a) the cost changes since receiving private investment compared with the average cost change for all Ontario LDCs over the same period [the “Cost Change Analysis”];[23]

b) the administrative costs per customer for the ‘privatized’ LDCs compared with the administrative costs per customer for their peer group[24] [the “Per Customer Analysis”]; and

c) the administrative costs per kilometre of distribution line for each ‘privatized’ LDC compared with their peer group average [the “Per km Analysis”].[25]

a) Cost Change Analysis

The administrative and O&M cost changes of LDCs since privatization were compared with the average provincial change over the same time period.[26] To remove the effects of volume-based cost changes, the percentage change in billed kilo-watt hours (kWh) within each LDC was deducted from the percentage cost change.[27,28] Both Algoma Power and Canadian Niagara (the two privately operated LDCs) have illustrated favourable cost changes since privatization relative to the provincial average. Since 2009, Algoma Power, while outperforming the provincial average in administrative cost changes by 18 per cent, has underperformed the provincial average on O&M costs by 2.5 per cent.[29] Canadian Niagara has outperformed the provincial average for both administrative and O&M costs since 2002, by 8 per cent and 40 per cent respectively. The results for the five LDCs with minority private ownership, but municipally-run operations, are less impressive. Only Westario Power and Entegrus outperformed the provincial average, and only with respect to one category each. For Enersource, Grimsby Power

Figure 3 – Privately-Owned Ontario LDCs

LDC	**% Private**	**Shareholder**	**Acquisition Year**	**Operations**
Algoma Power Inc	100	FortisOntario	2009	FortisOntario
Canadian Niagara Power Inc	100	FortisOntario	2002	FortisOntario
Enersource hydro Mississauga Inc	10	Borealis/OMERS	2001	Municipality
Entegrus Powerlines Inc	10	Corix	2008	Partnership*
Grimsby Power Inc	10	FortisOntario	2009	Partnership*
Rideau St Lawrence Distribution Inc	10	FortisOntario	2000	Partnership*
Westario Power Inc	10	FortisOntario	2000	Partnership*

* Under a partnership arrangement with the municipality retaining primary operating responsibility

niagarathisweek.com/news-story/3279191-grimsby-power-a-step-closer-to-fortis-deal/>.

23 OEB data goes back to 2002, for LDCs privatized between before 2002, 2002 has been used as the starting point.

24 The OEB benchmarks each LDC on a peer group basis which factors in geographic location of the LDC, the size of its customer base and the degree of undergrounding within its network.

25 While administrative costs should in theory be proportionate to the number of customers it was anticipated that there may be some cost variances based on the geographic area covered, therefore in order to make solid conclusions about the comparisons it was necessary to perform both a “Per Customer Analysis” and a “Per km Analysis”.

26 Comparing cost changes over the same period equalizes technological or operating innovations and inflation.

27 For instance, since privatization Algoma Power’s administrative costs have decreased by 5.0% while the volume of billed kWh has increased by 3.3%, therefore Algoma Power’s net change was -8.3%. Over the same period the average administrative costs across the province increased by 11.8% while the volume of billed kWh increased by 1.9%, therefore the provincial net change was 10.0%. To determine if the LDC outperformed the rest of the province the LDC’s net change was then deducted from the provincial net change. In this example, Algoma Power outperformed the provincial average by a spread of 18.3% (= 10% - (-8.3%)).

28 Previous comparisons of LDC cost changes since privatization were done on an absolute basis and failed to factor in volume based changes, for example see Murray Elston, Floyd Laughren and David McFadden, *The Report of the Ontario Distribution Sector Review Panel* (December 2012) at 23.

29 O&M cost increases are likely explainable by the fact that Algoma Power is the least densely populated of the province’s LDCs. Between 2009 and 2013 oil increased from $45 to more than $100. Given the increased distances

and Rideau St Lawrence the price changes have been significantly higher than the provincial average *(See Figure 4)*.

b) Per Customer Analysis

This analysis compared the per customer administrative costs for each 'privatized' LDC with their peer group average. Combined with the "Per km Analysis", this provides insight into whether 'privatized' LDCs operate more cost effectively *(See Figure 5)*.

Five of the seven 'privatized' LDCs had lower administrative costs per customer than their peer group average. The two other LDCs, Algoma Power and Enersource, were significantly more expensive on a per customer basis than their peer group, 47 per cent and 37 per cent respectively. On average the 'privatized' LDCs were 3.1 per cent more expensive, but 2.5 per cent cheaper with Enersource excluded.

c) Per km Analysis

This analysis compared the administrative costs per km for 'privatized' LDCs with its peer group *(See Figure 6)*.

Figure 4 – Cost Change Since Privatization Relative to Volume Change

LDC	Admin vs. Provincial Average	O&M vs. Provincial Average
Algoma Power Inc	**-18.23%**	2.31%
Canadian Niagara Power Inc	**-7.82%**	**-39.65%**
Enersource Hydro Mississauga Inc	17.84%	42.06%
Entegrus Powerlines Inc	39.39%	**-12.94%**
Grimsby Power Inc	44.07%	85.58%
Rideau St Lawrence Distribution Inc	44.95%	71.13%
Westario Power Inc	**-23.25%**	127.13%

Note: Outperformance of provincial average is emboldened

Figure 5 – LDC Administrative Cost per Customer (2013)

LDC	LDC $	Peer Group $	% Difference
Algoma Power Inc	$423	$287	+47.4%
Canadian Niagara Power Inc	$172	$196	**-12.2%**
Enersource Hydro Mississauga Inc	$159	$117	+36.5%
Entegrus Powerlines Inc	$152	$164	**-7.3%**
Grimsby Power Inc	$149	$196	**-24.0%**
Rideau St Lawrence Distribution Inc	$197	$217	**-9.1%**
Westario Power Inc	$148	$164	**-12.2%**

Figure 6 – LDC Administrative Cost per km (2013)

LDC	LDC $	Peer Group $	% Difference
Algoma Power Inc	$2,666	$8,763	**-69.6%**
Canadian Niagara Power Inc	$4,813	$10,614	**-54.7%**
Enersource Hydro Mississauga Inc	$6,180	$5,741	+7.6%
Entegrus Powerlines Inc	$6,432	$8,916	**-27.9%**
Grimsby Power Inc	$6,595	$10,614	**-37.9%**
Rideau St Lawrence Distribution Inc	$11,086	$12,006	**-7.7%**
Westario Power Inc	$6,508	$8,916	**-27.0%**

In this analysis six of the seven 'privatized' LDCs were cheaper than their peer group average. Notably, Algoma Power and Canadian Niagara both exhibited savings of between 50-70 per cent over their respective peers. Only Enersource was more expensive than its peer group. On average the 'privatized' LDCs were cheaper than their peer group by 31.0 per cent, or 37.4 per cent with Enersource excluded.

While admittedly a small sample size, the results do suggest that while private ownership alone may not trigger cost savings, private involvement in LDC operations has led to cheaper costs (see *Figures 3, 4 & 5*). In support of this conclusion the anomaly of Algoma Power deserves greater discussion. While it is the most costly LDC in the province on a per customer basis it is also the LDC with the lowest population density and second largest area. Given however that Algoma Power has significantly outperformed the rest of the province in administrative cost changes (see *Figure 4*) since Fortis took ownership 5 years ago, it still supports private sector involvement in LDC operations.

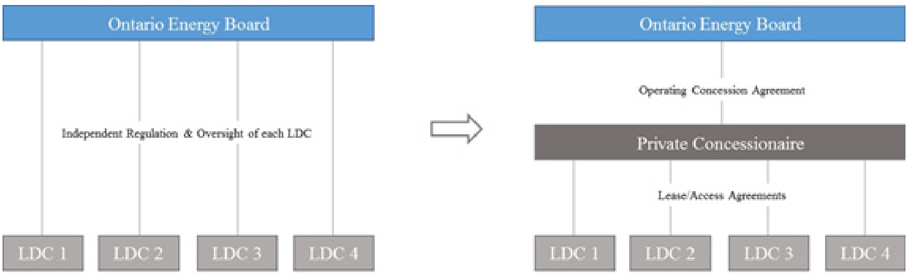
Recommendation 2: Develop Operating Concessions for the RDCs

Operating concessions can achieve desired cost savings while also overcoming many of the roadblocks previously discouraging private sector involvement in the LDC sector. Such concessions overcome the lack of competition "in the market" by creating competition "for the market".[30]

First, the privatization of Ontario's LDCs has been a politically sensitive issue. Three fears underlie this sensitivity: worries that privatizing distribution networks would lead to abuse of the natural monopoly through higher pricing,[31] a reduction in non-user benefits associated with the service, and finally a loss of public control of vital infrastructure.[32] While concession contracts cannot alter the physical monopoly of LDCs, they do create an alternative means of fostering competition. By tendering on a fixed price basis fears of cost abuse are muted, and the public will be assured of the most cost effective solution.[33] At the expiry of each contract term, a re-tendering process will ensure updated pricing and again assure the public of the most cost effective solution. In addition, concerns that tendering will lead to a loss of non-user benefits should be allayed by past examples of tendering which have avoided such losses. For example, the recent tendering of garbage removal in parts of the City of Toronto has led to both lower costs and improved service.[34] Finally, under operating concessions the municipalities would retain ownership of the LDCs and associated infrastructure, and merely enter into access arrangements with the private concessionaire (see *Figure 7*).

Second, Ontario's transfer tax system has been

Figure 7 – Proposed Concession Contractual Structure



covered by Algoma Power crew, energy prices comprise a larger portion of Algoma Power's cost than other LDCs.

30 Paul Joskow, "Regulation of Natural Monopoly" in Mitchell Polinsky & Steven Shavell (eds) *Handbook of Law and Economics,* ed 1,Vol 2, (Amsterdam: Elsevier, 2007) 1227 at 1290.

31 Michael J. Trebilcock & Roy Hrab, "Electricity Restructuring: A Comparative Review", Research Paper 41, online: University of Toronto (Faculty of Law) <http://www.law-lib.toronto.edu/investing/reports/rp41.pdf>.

32 *Gomez-Ibanez, supra* note 16 at 4-7.

33 It is likely adjustment for oil prices would be required – private operators cannot cost-effectively hedge this risk.

34 "Toronto has saved $11.9M through private garbage pickup", *CBC News* (December 16, 2013), online: <http://www.cbc.ca/news/canada/toronto/toronto-has-saved-11-9m-through-private-garbage-pickup-1.2466736>.

a major barrier to LDC consolidation in the province.[35] Concession contracts would be most efficiently structured on terms of less than 50 years so no transfer tax issues would be triggered,[36] thereby avoiding this potential roadblock.

Third, concerns of 'regulatory capture'[37] are minimized through concession arrangements because of the objective assessment and independent fairness processes involved. To additionally strengthen transparency in the system it would be preferable for the OEB to have public openings of concession bids, as is currently the practice in Chile for many of its public concessions.[38] Such transparency would further decrease the potential for "regulatory capture," a much more probable risk under the current cost-of-service regulation.[39]

Fourth, it has been feared that concession contracts in the electricity sector would not be able to capture technological improvements or would make regulatory oversight more difficult.[40] This may have previously been a valid concern but technology changes can now be accounted for through legal innovations like change orders and detailed performance indicators with associated penalties.[41] Further, improvements in computerized monitoring (i.e. SCADA systems) permit regulators to monitor performance on a real-time basis thereby better ensuring contractual promises are met.

Finally, the tendering of Ontario's LDC operations would likely generate significant interest from the private sector. In addition to Fortis and Corix, other Canada-based operators with the necessary qualifications would likely include ATCO, Emera, Enbridge and SNC-Lavalin. Moreover, given the IESO will provide a barrier between generators and distributors, there would be few reasons to prohibit electricity generators or foreign consortia from bidding as well.[42]

Conclusion

Empirical results illustrate that significant annual cost savings would be realized through consolidation of Ontario's smallest LDCs. While the emphasis has rightly been on encouraging consolidation, the focus of consolidation efforts should be on the Province's smallest LDCs, rather than larger ones like Hydro One Brampton. Additionally, policy makers and advisors should be more innovative with the means of bringing about such consolidation, resisting the urge to resort to an outright sale to private investors. Private investment alone has not been shown to be the key driver of cost savings; rather it is private operatorship which has derived savings. Tendering of LDC operations to private concessionaires therefore provides a suitable solution to the roadblocks currently preventing consolidation. In particular, a concessions program would not require costly amendments to the tax legislation and would avoid the political controversy involved in sales of public assets. Ontario's provincial government should therefore requisition the OEB and the Premier's Advisory Council on Government Assets to study the feasibility of creating RDCs and tendering of management of such entities to private sector operators. ■

35 *Fyfe, supra* note 4 at 21.
36 "Leases and the Land Transfer Tax Act", Ontario Ministry of Finance Bulletin, LTT 6-2000 (September 2009), online: OMF <http://www.fin.gov.on.ca/en/bulletins/ltt/6_2000.html>.
37 'Regulatory capture' refers to industry participants using regulation for their own benefit rather than for the public protection purpose it was designed to serve. It is an example of government failure. For greater discussion on 'regulatory capture' see George Stigler, "The Theory of Economic Regulation", *Bell J Econ Man Sci* vol 2:1 (1971).
38 Andrew Hill, "Foreign Infrastructure Investment in Chile: The Success of Public-Private Partnerships through Concession Contracts", *Northwestern Journal of International Law & Business* 32:1 165 at 180.
39 *Gomez-Ibanez, supra* note 16 at 35.
40 *Ibid* at 24-25.
41 For example see the *Driver Examination Services Project Agreement*, s 31, online: Infrastructure Ontario <http://www.infrastructureontario.ca/templates/projects.aspx?id=2147488447&langtype=1033>.
42 *Hunt, supra* note 17 at 6.

UTILITY DEALINGS WITH FREEMEN-ON-THE-LAND AND OTHERS RAISING "ORGANIZED PSEUDOLEGAL COMMERCIAL ARGUMENTS"

*Jason K. Yamashita**

Introduction

Utilities sometimes find themselves interacting with individuals who contend that they are not subject to generally applicable laws and obligations, such as the need to pay income taxes or utility bills. These individuals often attempt unilaterally to impose legal obligations upon others by the use of ornate-looking documents and procedures full of jargon resembling (but not quite amounting to recognizable) legal terminology.

In a small number of cases, these individuals have resorted to physical violence.

The courts have sometimes struggled with the confused and convoluted tactics of such individuals, which can consume a great deal of court time and interfere with matters such as tax enforcement proceedings, criminal prosecutions and family cases relating to child or spousal support. In 2012, Associate Chief Justice Rooke of the Alberta Court of Queen's Bench penned a detailed decision addressing these tactics in the case of *Meads v Meads*.[1] In that decision, he characterized their proponents as "a category of vexatious litigant" and labelled them "Organized Pseudolegal Commercial Argument" ("OPCA") litigants.[2]

This article will address OPCA tactics which may be encountered by utilities, and in particular how utilities might best deal with OPCA proponents to minimize the associated costs and risks.

How Do You Recognize an OPCA Proponent?

Many OPCA proponents are associated with informal groups or ideologies, such as "natural persons," "sovereign citizens," and "Freemen-on-the-Land". Despite the different labels, they appear to borrow many of their ideas and approaches from each other, often through online forums. While OPCA proponents may have a variety of worldviews, they are united by, and may be identified by, certain characteristics:[3]

> [4] OPCA litigants do not express any stereotypic beliefs other than a general rejection of court and state authority; nor do they fall into any common social or professional association. Arguments and claims of this

* Jason K. Yamashita is a lawyer at Farris, Vaughan, Wills & Murphy LLP in Vancouver. He gratefully acknowledges the comments and input of lawyers Ludmila B. Herbst and Erica C. Miller as well as the research assistance of Tamara Navaratnam, summer articled student, in the preparation of this article.

1 *Meads v Meads,* 2012 ABQB 571, [2012] WWR 419 [*Meads*]. This case was apparently the second-most-viewed case on CanLII (an online resource of Canadian case law accessible without charge) in 2013 and 2014: Slaw, online: <http://www.slaw.ca/2014/12/16/have-you-read-2014s-top-cases/>.

2 *Meads, supra* note 1 at para 1.

3 *Ibid* at para 4; cited with approval in *Bossé v Farm Credit Canada*, 2014 NBCA 34, 419 NBR (2nd) 1 at paras 45-46.

nature emerge in all kinds of legal proceedings and all levels of Courts and tribunals. This group is unified by:

1. a characteristic set of strategies (somewhat different by group) that they employ,
2. specific but irrelevant formalities and language which they appear to believe are (or portray as) significant, and
3. the commercial sources from which their ideas and materials originate.

This category of litigant shares one other critical characteristic: they will only honour state, regulatory, contract, family, fiduciary, equitable, and criminal obligations if they feel like it. And typically, they don't.

Characteristic Strategies

Characteristic strategies of OPCA proponents may include:

- asserting that statutes have no effect due to some defect in their enactment or the authority of the enacting legislature;[4]
- asserting that the OPCA proponent is only subject to "common law", "natural law", or "God's law";[5]
- asserting that a municipality, province or Canada is a corporation;[6]
- asserting that all interactions are contractual;[7]
- citing as legal authority obsolete, foreign or otherwise irrelevant works such as the Magna Carta, the *Constitution of the United States* or U.S. legislation such as the *Uniform Commercial Code*, admiralty law, the Bible (usually the King James version), and out-of-date versions of the *Income Tax Act* or Black's Law Dictionary; [8] and
- sending notices which claim to be binding legal documents such as contracts, waivers of rights, etc. (sometimes with deadlines by which a lack of response is said to be acceptance of contractual terms or other consequences) or "fee schedules" which purport to impose payment obligations on other parties.[9]

Formalities and Language

Examples of formalities and language use employed by OPCA proponents may include:

- the use of name-based strategies such as insistence on use of peculiar formats to name themselves and others (":john-jack:doe:"), denial of aspects of their identities to avoid obligation and liability (distinguishing between "John Jack Doe" and "JOHN JACK DOE" or between one's personal and corporate self), claiming to have copyrighted or trade-marked their names, and formalizing descriptions of themselves so as to assert purported rights ("John Jack Doe, sui generis, a man, hereby claiming all rights *nunc pro tunc*");[10]
- the use of particular phrases such as "flesh and blood man", "free will full liability person", "sovran" (from "sovereign") or arguments that the OPCA proponents are "agent" or "secured party" for themselves;[11]
- the use of abnormal formats or elements in mailing addresses, particularly with regard to postal codes ("near [v7z 1k4]");[12]
- the out-of-context use of documents purporting to be legal documents such

4 *Meads*, *supra* note 1 at paras 298-301, 343-345, 387; *Fearn v Canada Customs*, 2014 ABQB 114, 94 Alta LR (5th) 318 at paras 65-74 [*Fearn*].
5 *Meads*, *supra* note 1 at paras 228, 248; *Fearn, supra* note 4 at paras 47-60.
6 *Meads, supra* note 1 at paras 178, 222, 384; *Fearn*, *supra* note 4 at paras 65-69.
7 *Meads*, *supra* note 1 at paras 222, 379-404; *Fearn*, *supra* note 4 at paras 65-69.
8 *Meads*, *supra* note 1 at paras 228-229, 248; *Fearn*, *supra* note 4 at paras 39, 47-60.
9 *Meads*, *supra* note 1 at paras 447-528; *Fearn*, *supra* note 4 at paras 61-64, 195-200.
10 *Meads*, *supra* note 1 at paras 206-213; *Fearn*, *supra* note 4 at paras 10, 160.
11 *Meads*, *supra* note 1 at para 221; *A.N.B. v. Hancock*, 2013 ABQB 97, 55 AR 364 [*Hancock*], at paras 8, 71-72; *Bank of Montreal v Rogozinsky*, 2014 ABQB 771 at Appendix "E".
12 *Meads*, *supra* note 1 at paras 231-237; *Fearn*, *supra* note 4 at Appendix "A".

as affidavits, notices of objection, and liens;[13]

- the out-of-context use of legal terminology and concepts such as judgment, estoppel, waiver of tort, immunity, and the phrase "accepted for value";[14] and
- particular reliance upon formalization through registered mail, notaries and notarization, certified copies of documents and use of fingerprints or particular colours of ink on documents.[15]

Commercial Sources

The commercial sources for OPCA tactics are profit-oriented "gurus" who purport to educate others in various strategies intended to circumvent legal consequences and to frustrate the rights of governments, corporations and individuals. *Meads v Meads* addressed these gurus and their strategies:[16]

> [73] A critical first point is an appreciation that the concepts discussed in these Reasons are frequently a commercial product, designed, promoted, and sold by a community of individuals, whom I refer to as "gurus". Gurus claim that their techniques provide easy rewards – one does not have to pay tax, child and spousal support payments, or pay attention to traffic laws. There are allegedly secret but accessible bank accounts that contain nearly unlimited funds, if you know the trick to unlock their gates. You can transform a bill into a cheque with a stamp and some coloured writing. You are only subject to criminal sanction if you agree to be subject to criminal sanction. You can make yourself independent of any state obligation if you so desire, and unilaterally force and enforce demands on other persons, institutions, and the state. All this is a consequence of the fact gurus proclaim they know secret principles and law, hidden from the public, but binding on the state, courts, and individuals.
>
> [74] And all these "secrets" can be yours, for small payment to the guru.
>
> [75] These claims are, of course, pseudolegal nonsense. A judge who encounters and reviews OPCA concepts will find their errors are obvious and manifest, once one strips away the layers of peculiar language, irrelevant references, and deciphers the often bizarre documentation which accompanies an OPCA scheme...

While OPCA proponents may have fallen prey to such gurus financially, they have also exercised their own judgment in advancing OPCA strategies and should therefore be held responsible for the time and money which they cause others to expend.

Principles of OPCA Proponents

OPCA proponents take issue with the applicability of the law and the legal system to them, challenging or refusing to abide by "state, regulatory, contract, family, fiduciary, equitable and criminal obligations"[17] which meet their disfavour. They may advance arguments that the legal system does not apply to them because a higher law applies and takes precedence (such as "common law", natural law, admiralty law, merchant law, or the laws as recorded in a particular version of the Bible). They may

13 *Meads*, *supra* note 1 at paras 42, 135, 175, 181, 303, 397, 448, 477, 484-486, 496, 695-713, 482; *Fearn*, *supra* note 4 at paras 6, 178, 211, Appendix "A"; *Perreal v Knibb*, 2014 ABQB 15 at paras 8-13. In the case of *Dempsey v. Envision Credit Union*, 2005 BCSC 1730, an individual attempted to assert the applicability of divine law through a "Constructive Notice of Child of God Status".

14 *Meads*, *supra* note 1 at paras 217-219, 223, 302-370, 508, 477-478, 484-485, 488, 531-543; *Fearn*, *supra* note 4 at para 42; *Hancock*, *supra* note 11 at paras 71-72.

15 *Meads*, *supra* note 1 at paras 11, 211-212, 214-216, 243, 273-274, 344, 546, 688, 696.

16 *Meads, supra* note 1 at paras 73-75.

17 *Ibid* at para 4.

assert that the government is illegitimate, and incapable of passing binding laws, due to a defect of past legislation or a defect of officials' oaths or some other technical shortcoming. Fundamentally, however, they are grouped together because of their unconventional approaches to denying their obligations.

Documents Used by OPCA Proponents

Certain documents are characteristic of OPCA tactics and may be encountered by utilities, often as forms which are filled in or varied by individual customers.

As noted above, a frequent OPCA tactic is to attempt to unilaterally foist obligations on others, including police officers, courts, and court personnel. The OPCA proponent might send a document purporting to impose a fine, declare that the OPCA proponent is no longer required to pay income taxes or meet another obligation, or establish a contractual relationship. Sometimes documents in this category claim to be binding if the recipient does not disagree or meet some other condition within a specified time frame. Associate Chief Justice Rooke in *Meads v Meads* refers to these purported obligations as foisted unilateral agreements, and notes that they do not create binding legal obligations and are in that sense examples of "magic hats" (gimmicks relied upon as though they imparted legal immunity).[18] A unilaterally imposed agreement is not an agreement at all, of course, as it reflects the wishes of only one party. Where OPCA proponents attempt to use foisted unilateral agreements to restrict the court, the attempt is not only ineffective but a challenge to the operation of the court which constitutes *prima facie* civil contempt.[19]

Few OPCA cases involve enforcement of utility payment obligations, perhaps because service is often simply disconnected for non-payment. One utility-related decision that has made it before the courts is *R v Leis*, a criminal case in which OPCA proponent Stuart Leis was committed to custody for breach of a conditional sentence order which required that he not communicate with public officials except in the course of their normal duties.[20] In a clear example of a unilaterally foisted obligation, Mr. Leis purported to appoint the Director of Vital Statistics as his power of attorney and directed utilities to send his bills to the person holding that office. His defence was to deny the validity of the conditional sentence order; it was unsuccessful both before the lower court and upon appeal.

OPCA proponents have also attempted the unilateral imposition of agreements to discharge debt, and of penalties on lawyers attempting to collect on debts.[21]

A British Columbia utility, BC Hydro, has been targeted by the unilateral foisted agreement tactic, which is being actively encouraged by the person or persons operating the "BC-Freedom.com" website in the context of the utility's past-due notices and smart meter installations (although the website's operator(s) do not expressly link themselves to any particular OPCA group and it is not clear whether they seek payment for the information provided).[22] The website offers step-by-step instructions on how to supposedly "Void Alleged Past Due Notices" and "Voiding alleged BCUC MCP Approval Notification".[23] The latter reference is to the BC Utilities Commission's approval of charges related to BC Hydro's Meter Choices Program, by which eligible customers were given a choice between installation of a smart meter, installation of a radio-off smart meter, or continued use of their existing meter (the latter two options require payment of certain charges).[24] The website's proponent(s) claims that:

(a) once a customer "voids for defect" a past due notice or overdue notice from BC Hydro and returns the original to BC

18 *Ibid* at paras 447-528.

19 *Fearn*, *supra* note 4 at paras 195-196.

20 *R. v Leis*, 2008 SKQB 123, 77 WCB (2d) 323, aff'd 2008 SKCA 103.

21 *Gravlin v Canadian Imperial Bank of Commerce*, 2005 BCSC 839, 140 ACWS (3d) 447.

22 Online: BC-Freedom <bc-freedom.com>.

23 "Voiding Alleged Past Due Notices", online: BC-Freedom <https://bcfreedom.files.wordpress.com/2014/03/void-alleged-past-due-notices1.pdf>; "VOIDING *alleged* BCUC MCP APPROVAL NOTIFICATION", online: BC-Freedom <http://bcfreedom.files.wordpress.com/2014/06/void-alleged-bcuc-mcp-approval-notification.pdf>.

24 *Application for Approval of Charges Related to the Meter Choices Program* (25 April 2014), British ColumbiaUtilities Commission, Decision, online: BCUC <http://www.bcuc.com/Documents/Proceedings/2014/DOC_41266_04-25-2014_BCH%20Meter%20Choices_Decision_G-59-14.pdf>.

Hydro, the notice is void for fatal defect; and

(b) once a customer sends certain documentation to BC Hydro by registered mail, and it is signed for by BC Hydro without rebuttal, the customer has ended his or her obligation to pay legacy meter charges.

These claims have not been considered by courts or tribunals.

One form of unilaterally imposed agreement which is worthy of particular note is the "fee schedule", which purports to be an agreement requiring specific payments to the OPCA proponent if a certain action is taken or a certain result occurs. The courts have uniformly refused to enforce so-called agreements of this sort.[25]

The fee schedule tactic may be employed by OPCA proponents in matters involving utilities. In a British Columbia case, a company operating a trailer park resisted enforcement actions undertaken by a safety authority in relation to the condition of power poles and equipment by refusing to comply, demanding payments under a fee schedule, and eventually commencing legal proceedings against individual representatives of the safety authority. The court rejected the fee schedule as "a nonsensical concoction designed to hinder and harass those against whom such claims are made" and awarded partial special costs.[26]

A utility (which preferred not to be identified) reported having recently received "notice of liability" forms which included fee schedule clauses with the following language:

> 9. A fee schedule of _______________ United States Dollars (________) *per* day for any and all harm shall be due and payable to Claimant/Libellant, or to another recipient or organization if specified in writing by the Claimant/Libellant.
>
> 10. Any fees not paid within thirty days of presentment of a true bill, you agree to a lien against you, subject to levy, distraint, distress, certificate of exigency, impound, execution and all other lawful and or commercial remedies, including but not limited to Private Discharging and Indemnity Bond **RW 602 596 009 CA**.

The amounts filled in at the blank spaces by different senders varied from US$10,000 to $20,000, but also included "100 ounce troy 0.9999 fine gold".

Variations Among OPCA Proponents

OPCA proponents vary widely in their personal and political views and in their approaches to resisting their obligations. They may have extreme right wing views[27] or extreme left wing views;[28] some assert religious foundations for their beliefs;[29] others base their tactics in First Nations rights.[30] It should not be assumed that the views of one OPCA proponent or group are shared by others who adopt similar tactics. Frustrating (or worse) experiences with an OPCA proponent should not result in disproportionate responses to others.

It may be that some OPCA proponents take more issue with form than substance. For example, they may wrongly think that payment of a bill with a particular naming format will deprive them of a right in some other forum, while having no particular objection in principle to paying for services used. Acceptance of bill payment under protest might be appropriate in some circumstances.

What Are the Risks Associated with OPCA Proponents?

OPCA proponent customers pose significant challenges and potential risks to utilities.

25 *Meads*, *supra* note 1 at paras 505-511.
26 *Gidda v Hirsch*, 2014 BCSC 1286, at para 84.
27 *Warman v Warman*, 2005 CHRT 36.
28 *Jackson v Canada (Customs and Revenue Agency)*, 2001 SKQB 377.
29 *Sandri v Canada (Attorney General),* 2009 CanLii 44282 (ON SC), 179 ACWS (3d) 811; *Pappas v The Queen*, 2006 TCC 692.
30 *The Natural and Sovran-on-the-Land, Flesh, Blood and Bone North American Signatory Aeriokwa Tence Kanienkehaika Indian Man v Canada*, 2011 ONSC 1308; in B.C. two individuals assert that they constitute the Sovereign ©Skwxwú7mesh-Squamish™ Government, online: <http://www.sovsquamishgov.org/> (not to be confused with the Squamish Nation Government).

Wasted Time

Usually the main difficulty OPCA proponents cause utilities is that inordinate time may be consumed in dealing with them in which little or nothing is accomplished. A utility (which preferred not to be identified) emphasized the significant customer relations staff time required for each of its OPCA proponent interactions. OPCA proponents can be clever and well-spoken, and some are skilful at navigating and taking advantage of procedures and policies.

Identification of OPCA proponents can limit wasted time and separate such customers from those more likely to be advancing legitimate concerns. Of course, customers should be dealt with in a consistent fashion and an OPCA proponent customer's concerns, if legitimate, should be addressed accordingly.

Utilities may be confronted with the issue of OPCA agents or representatives. OPCA proponents have sometimes attempted to have agents or representatives who are OPCA gurus speak before the courts on their behalf. Generally speaking, while anyone may act on his or her own behalf, only lawyers (and certain others, such as articling students, who may do so to a limited extent) are permitted by law to represent others in court.[31] Utilities may rely upon their policies and, where applicable, privacy legislation to limit their interactions with persons other than customers.

To avoid duplication of customer relations staff efforts, it may sometimes make sense to have a single staff person deal with a particular OPCA proponent. This person will then have familiarity with the OPCA proponent and past interactions.

Where utility bills are unpaid, or other customer obligations unmet, and the OPCA proponent relies upon the tactics described in this article or in *Meads v Meads*, the utility should look to its tariff and standard disconnection practices.

Potential Violence

In some cases, OPCA proponents have resorted to violence or threatened violence.

Two provincial law societies have warned lawyers about potential personal safety issues from OPCA proponents.[32] The Law Society of British Columbia issued practice tips noting the common OPCA proponent belief in an unrestricted right to possess and use firearms, and referring to a routine traffic stop of a "sovereign citizen" that ended in the death of two police officers in the United States.[33] An FBI publication characterized sovereign citizen extremists as a domestic terror movement.[34]

There are also examples of potentially violent OPCA proponents in Canada. Eldon Warman, a "sovereign natural citizen of the Anglo-Saxon common law", was found guilty of assaulting a peace officer who stopped him to check his commercial vehicle permit.[35] Glenn Fearn was specifically described as an OPCA litigant in civil proceedings related to criminal charges for smuggling weapons and ammunition.[36] While not alleged to have committed violent acts, he argued before the court that he could use lethal force against Customs Officers if they arrested him unlawfully.[37] One media report linked Justin Bourque, accused killer of three RCMP officers, to the Freeman movement (although this connection appears to have been conjectural).[38]

31 See, for example, the *Legal Profession Act*, SBC 1998, c 9, s 15; *Legal Profession Act*, RSA 2000, c L-8, s 106.

32 "OPCA Litigants – The Phenomenon of Freemen on the Land", online: Law Society of Alberta <http://www.lawsociety.ab.ca/default/whats_new/2013/09/25/opca-litigants-the-phenomenon-of-freemen-on-the-land>; "The Freeman-on-the-Land movement", online: Law Society of British Columbia < http://www.lawsociety.bc.ca/page.cfm?cid=2627>.

33 Dave Bilinsky, "The Freeman-on-the-Land movement" (2005) 4 Benchers' Bulletin 11, online: Law Society of British Columbia <https://www.lawsociety.bc.ca/docs/bulletin/bb_2012-04-winter.pdf>.

34 Hunter and Heinke, "Sovereign Citizens: A Growing Domestic Threat to Law Enforcement" (September 2011) FBI Law Enforcement Bulletin, online: Federal Bureau of Investigation <http://www.fbi.gov/stats-services/publications/law-enforcement-bulletin/september-2011/sovereign-citizens>.

35 *R v Warman*, 2000 BCPC 22, leave to appeal ref'd 2001 BCCA 510.

36 *Fearn*, *supra* note 4.

37 *Ibid* at para 21.

38 Joseph Brean, "Moncton shooting accused may be a classic 'pseudo-commando' with anti-government Freeman ideology" *National Post* (5 June 2014), online: National Post <http://news.nationalpost.com/2014/06/05/moncton-shooting-accused-may-be-a-classic-pseudo-commando-with-anti-government-freeman-ideology/>.

One utility (which preferred not to be identified) recounted repeated contact with an OPCA proponent who advised that he was recording telephone conversations with utility staff. He threatened to kill himself publicly and to put the suicide and telephone recordings on an internet video website. The utility contacted the police, who were previously aware of the individual and apparently discussed the matter with him.

While only a small minority of OPCA proponents have threatened or committed violent acts, utilities should nevertheless exercise caution when dealing with any such individuals. Threats of violence should be documented and reported to police and other appropriate authorities. Utilities should elevate precautions when sending staff to visit property associated with known OPCA proponents, such as ensuring that staff do not attend the property alone and that they apprise others of their intention to visit in advance.

Consequences of Insufficient Response

There may also be consequences of ignoring OPCA proponents or failing to sufficiently address their tactics. OPCA proponents should not be automatically ignored or too readily discounted. While demands with no basis need not be complied with or even acknowledged, and a utility is not required to justify each action to OPCA proponents, it is important that utilities comply with their legal and contractual obligations and applicable policies so as to avoid exposure to technical arguments arising from procedural lapses. Legal advice should be sought if there is any doubt as to whether a legal obligation could arise from particular actions.

Background Resources

The lengthy *Meads v Meads* decision makes a colourful, entertaining read. It serves as a resource for those encountering OPCA tactics, particularly in the court system. While it debunks many OPCA tactics, however, it does not lead automatically to the conclusion that use of such tactics invalidates whatever potentially valid rights or arguments the OPCA proponent has.[39] Where there are legitimately arguable claims or positions raised or available to an OPCA proponent, these must be considered and addressed appropriately.

Another helpful resource is the decision of *Fearn v Canada Customs*, a 2014 decision written by Mr. Justice Tilleman of the Alberta Court of Queen's Bench.[40] It develops some of the conclusions found in *Meads v Meads* and provides further references to case law, including recent decisions.

Recommendations for Utilities Dealing with OPCA Proponents

Utilities may wish to consider the following brief recommendations for dealing with OPCA proponents:

- Some OPCA proponents' concerns can be resolved with appropriate customer relations approaches. A common OPCA proponent theme is denial of one's name or the format of one's name. A utility had recurrent issues of this sort with a customer who refused to pay his bills because the utility spelled his name entirely in capital letters. After much back-and-forth with utility staff, he eventually agreed to monthly prepayment to avoid the issuance of bills addressed to him on that basis. The name denial tactic, of course, can have no possible basis where the OPCA proponent applied for service under that name. Utilities may also wish to look to their tariff disconnection policies if a customer denies that he or she is the person who requested service.

- Do not attempt to meet each novel argument advanced on its merits. Focus on practical and efficient resolution of the matter.
- Provide customer service staff with tools to identify and flag the files of OPCA proponents for future reference. Consider the adoption of specific policies with regard to documenting communications with OPCA proponents and, in particular, the safety of staff interacting with them (such as those attending at property associated with OPCA proponents).
- Look to the tariff or service contract and its obligations. Exercise normal business

39 See *Meads*, *supra* note 1 at para 736.
40 *Fearn*, *supra* note 4.

judgment pursuant to those obligations in terms of bill payment, cut-off of service, reinstatement of service, and so on.

- Ensure careful compliance with applicable laws, regulations and policies. Document this compliance rigorously. Lawyers with extensive experience in dealing with OPCA proponents note that these individuals often exhibit an uncanny ability to interpret law and policy, at times raising technical compliance arguments when it is in their interests to do so.
- Remember when defending a legal claim that the applicant is seeking relief from the court or tribunal. In that circumstance, their ability to contest jurisdiction or their own identity should be challenged. For example, an individual asserting he or she is someone else must establish a contractual relationship or some other basis upon which utility services should be provided to him or her. An individual asserting he or she is not bound by the court's jurisdiction should not have brought the proceeding in that court.
- If legal proceedings are brought, bring to the judge's (or decision maker's) attention the cases of *Meads v Meads* and *Fearn v Canada Customs*. Many seemingly novel OPCA strategies have now been addressed comprehensively in these decisions.
- A specific point on which *Meads v Meads* may be helpful is in seeking elevated costs against an OPCA litigant.[41] ■

41 *Meads, supra* note 1 at paras 594-600.

PIPELINES, THE NATIONAL ENERGY BOARD AND THE FEDERAL COURT

*Nigel Bankes**

The construction of new pipelines, and the expansion, reversal or re-purposing of existing pipelines have always attracted controversy in Canada and the almost inevitable applications for judicial review or appeal. Consider, for example, the efforts to license the Makenzie Natural Gas Pipeline (and its variants) in the 1970s,[1] the licensing of the Norman Wells Pipeline in the 1980s,[2] and the licensing of the Express Pipeline in the 1990s.[3] But those experiences have hardly prepared us for either the spate of pipeline applications currently before the National Energy Board (NEB, the Board), or the number of applications by interested parties to the Federal Court of Appeal contesting the Board's treatment of these applications. The Board itself seemed to recognize this earlier this year (2015) when it developed a new page on its website to assist users to keep track of the various Federal Court applications.[4]

This paper has the modest goal of providing a largely descriptive account of the issues and the state of play of the relevant pipeline and Court applications. The paper first discusses the legal framework of the *National Energy Board Act*[5] (*NEBA*) and the *Federal Courts Act*[6] within which the NEB and the Federal Court of Appeal operate before examining the major pipeline proposals and the related Court applications.

The Legal Framework

No person may construct or operate an interprovincial or an international pipeline without a certificate of public convenience and necessity (CPCN) issued by the NEB.[7] The procedure for issuing a CPCN now entails the NEB making a report and recommendation with respect to the issuance of a certificate to the Governor in Council and the referral back, acceptance or rejection of that recommendation by the Governor in Council.

The Board may recommend approval or rejection, but either way must indicate all the terms and conditions that it considers "necessary or desirable in the public interest" should the project go ahead.[8] Section 22(4) of the *NEBA* provides that the NEB's report is not "a decision or order of the Board" within the meaning of s. 22(1) of the Act with the necessary implication that the report cannot be made the subject of an appeal to the Federal Court of Appeal, with leave, on a point of law or jurisdiction under that same subsection of

* Nigel Bankes is a Professor of Law at the University of Calgary, and Adjunct Professor at the University of Tromsø.

1 These applications led to the Berger Inquiry, the NEB's Northern Pipeline Inquiry and one of the Supreme Court of Canada's most important decisions dealing with the alleged bias of a tribunal member: *Committee for Justice and Liberty v National Energy Board,* [1978] 1 SCR 369.

2 See *Committee for Justice and Liberty Foundation v Interprovincial Pipe Line (NW) Ltd,* [1982] 1 FC 619 (FCA).

3 See *Alberta Wilderness Association v Express Pipelines Ltd (1996),* 137 DLR (4th) 177 (FCA) [*Express*].

4 See the Board's website at https://www.neb-one.gc.ca/index-eng.html, and follow Applications and Filings and then Court Challenges.

5 *National Energy Board Act*, RSC 1985, c N-7 [*NEBA*].

6 *Federal Courts Act*, RSC 1985, c F-7.

7 *NEBA, supra* note 5, ss 30-31.

8 *NEBA, supra* note 5, s 52(1).

the Act.[9] It does not follow from this however that there can be no application for judicial review in respect of a report because of a line of decisions interpreting s. 18.5 of the *Federal Courts Act*.[10] These decisions tend to suggest that an application for judicial review is only precluded by that section to the extent that the decision is actually appealable.[11] The Federal Court Trial Division has no jurisdiction over the NEB.[12]

While the Governor in Council may require the Board to reconsider its recommendation or any of the terms and conditions,[13] in the ordinary course, the Governor in Council, by order, may direct the Board to issue a CPCN, subject to the terms and conditions in the Board's report, or direct the Board to dismiss the application.[14] The order must provide reasons[15] and s. 55 of the *NEBA* expressly provides for judicial review, with leave, from the Federal Court of Appeal.[16]

The construction of a large diameter new pipeline will also trigger review under the new *Canadian Environmental Assessment Act, 2012*[17] (*CEAA 2012*) (or the predecessor version of that statute). Under the previous version of that statute the involvement of other federal or provincial agencies often led to projects being referred to a Joint Review Panel (JRP) resulting in additional complications in terms of the judicial supervision of the JRP.

In the case of federally regulated pipelines, a JRP Report discharged the Panel's responsibility under both the *CEEA* and the *NEBA*. Insofar as *CEEA* panels are not listed in s. 28 of the *Federal Courts Act* as a federal board, commission or other tribunal over which the Federal Court of Appeal has exclusive supervisory jurisdiction, it must follow that any judicial supervision of this aspect of a JRP's responsibility would fall to the Federal Court Trial Division. Thus, in cases involving JRPs, interested parties could elect to proceed in either or both Federal Court Trial Division (with respect to the *CEEA* panel responsibilities) and the Federal Court of Appeal (with respect to the NEB matters).[18] This was the case for example in the litigation which followed the approval of the Express Pipeline. There, matters were consolidated by agreement of the interested parties in a hearing before the Federal Court of Appeal. In his judgement Justice Hugesson commented on this way of proceeding as follows:[19]

> While the procedure followed by the applicants was not the subject of much discussion before us (it being clear that at least one of the applications must be the appropriate method of attack)

9 It bears mentioning however that Board reports may address both s. 52 public convenience and necessity issues and tolling issues under Part IV of *NEBA*. These matters are presumably still amenable to the s. 22 appeal with leave procedure although in many cases it is difficult to frame such issues as questions of law or jurisdiction (particularly given the very general guidance that *NEBA* offers, see s. 62); and even if that hurdle can be passed the standard of review is likely reasonableness. See *British Columbia Hydro and Power Authority v West Coast Transmission Ltd*, [1981] 2 FC 646 and *TransCanada PipeLInes Ltd v Canada (National Energy Board)*, 2004 FCA 149.

10 Section 18.5 provides that "if an Act of Parliament expressly provides for an appeal to the … Federal Court of Appeal …. from a decision or order…. that decision or order is not, *to the extent that it may so appealed*, subject to review or to be restrained, prohibited or removed, set aside or otherwise dealt with, except in accordance with that Act" (emphasis supplied).

11 The decisions include *Union of Nova Scotia Indians v Maritimes and Northeast Pipeline Management Ltd*, 1999 CanLII 7556 (FCA) and *Forest Ethics Advocacy Association v National Energy Board*, 2014 FCA 245 [*Forest Ethics*]. These decisions are likely not determinative however since the parties must likely still show that the Board's report and recommendations under s. 52 are enough of a "decision" to qualify for judicial review, but that should not present too much difficulty: *Re Abel and Advisory Review Board* (1980), 119 DLR (3d) 101 (Ont. CA). In this context it may be important to note that s. 22(4) stipulates that the for greater certainty language ofthat sub-section is "for the purposes of this section" and not, for example, "for all purposes".

12 *Sweetgrass First Nation v Canada (Attorney General)*, 2010 FC 535 [*Sweetgrass*]; *Centre québécois du droit de l'environnement v National Energy Board*, 2015 FC 192. The earlier decision of the Federal Court Trial Division in *Industrial Gas Users Association v Canada* (1990), 33 FTR 217 is no longer authoritative following reforms to the *Federal Courts Act* in 1990 – 1992.

13 *NEBA, supra* note 5, s 53.

14 *Ibid,* s 54(1).

15 *Ibid,* s 54(2).

16 See also s 28(1)(g) of the *Federal Courts Act.*

17 *Canadian Environmental Assessment Act*, 2012, SC 2012, c 19 [*CEAA, 2012*].

18 See *Sweetgrass, supra* note 12 at para 37.

19 *Express, supra* note 3 at paras 6-7.

> we think we should comment on it briefly. As a matter of judicial policy and economy it appears to us that where both a panel report and a subsequent action by a responsible authority are attacked those attacks should if possible be heard together and in the same Division of the Court. Thus where, as here, the responsible authority is one which is listed in section 28 of the Federal Court Act judicial review should be started in (for the authority) or transferred to (for the panel) the Appeal Division.
>
> Likewise, where, as here, the responsible authority is one whose decisions are appealable to this Court and judicial review thereof is consequently limited by the terms of section 18.5 of the Federal Court Act the preferred route should be the application for leave to appeal. That is especially the case here where the panel and the authority are in fact (and we think in law) the same body although exercising functions under more than one statute.

While this body of law is of some relevance for the Northern Gateway Project (since it too was the subject of a joint review panel) we are unlikely to see joint review panels involving the NEB in the future since *CEAA, 2012* accords the NEB the authority to conduct assessments without the involvement of the Agency.[20]

The Projects

With this background, which has covered both the procedure for obtaining a CPCN and the judicial supervision of the NEB, the paper now turns to consider the different NEB\JRP projects that are currently the subject of judicial review or appeal applications. The projects covered are Enbridge's Northern Gateway Project, Enbridge's Line 9B Project, the TransMountain Expansion Project and TransCanada's Energy East Project.

Enbridge Northern Gateway Project

Enbridge's Northern Gateway Project is a proposal to construct and operate two pipelines between Bruderhiem, Alberta and Kitimat British Columbia and to construct and operate a marine terminal and associated berthing and storage facilities at Kitimat. One pipeline would be an oil export pipeline with the capacity to carry 525,000 bbls per day. The other pipeline would import condensate with a capacity of 193,000 bbls per day. The project was referred to a joint review panel. The JRP issued its Final Report on the project on December 19, 2013.[21] The JRP had the responsibility under the *CEAA* to assess the effects the project could have on people and the environment, their significance, and how these effects might be mitigated, and whether the project met the public convenience and necessity test of the *NEBA*.[22] The JRP recommended approval of the project subject to 209 conditions. In doing so the JRP concluded that the project would, in combination with the effects of other projects, have a significant adverse environmental effect on certain populations of woodland caribou and populations of grizzly bear (listed species under the *Species at Risk Act*[23]) - even after all of Northern Gateway's mitigation efforts. Nevertheless, the JRP recommended that these significant effects could be justified in the circumstances.[24] The particular circumstances that led to this conclusion included the ability of the Project to diversify Canada's oil markets and condensate supply, and the other economic and social benefits of the project.[25]

As discussed in a previous issue of this *Quarterly,*[26] various judicial review and appeal applications have been launched with respect to both the JRP Report and the decision of the Governor in Council. All of these applications have been consolidated[27] and

20 CEAA, 2012, *supra* note 17, ss 14(4), 15, 28–31.

21 National Energy Board, *Connections, Report of the Joint Review Panel for the Enbridge Northern Gateway Project, vol 1* (Calgary: NEB 2013) [*Connections*].

22 *NEBA, supra* note 5, s 52.

23 *Species at Risk Act,* SC 2000, c 29.

24 *Connections, supra* note 21 at 57.

25 *Ibid* at 74.

26 Nigel Bankes, "Enbridge's Northern Gateway Project: cabinet approval but complex court proceedings" (2014) Energy Regulation Quarterly 193 [*Bankes*].

27 See *Forest Ethics Advocacy Association v Canada (Attorney General),* 2014 FCA 182, and apparently a supplementary order of December 17, 2014 referred to in *Gitxaala Nation v Canada,* 2015 FCA 27 at para 1.

a schedule established with a view to a hearing in Fall 2015. My earlier paper provided a discussion of the pleadings in those applications (as of August 2014) and interested readers should refer to that discussion.[28]

This section comments on three interlocutory decisions which have been reported since then.[29] The first two decisions were handed down by Justice Stratas on January 27, 2015. The straightforward issue in the first of these, *Forest Ethics Advocacy Association v Northern Gateway Pipelines Inc,*[30] was whether the NEB should be added as a respondent in one particular application, A-514-14, the NEB having already obtained that status in the consolidated applications. The appellants opposed respondent status suggesting that the NEB should be treated as an intervener on the grounds that a tribunal has only limited participation rights on an appeal or judicial review of one of its decisions. Justice Stratas concluded that the Board's submission showed that it was well aware of the limits on its participation, and that since, in a technical sense, the application is an appeal from the Board's decision, the NEB should be treated as a respondent.

The second decision handed down in January, *Gitxaala Nation v Northern Gateway Pipeline Inc*,[31] dealt with the extent to which parties might be able to supplement the record with affidavits. The Court anticipated this issue in its consolidation order of December 2014. In that Order, the Court took the position that it would not allow affidavit evidence with respect to constitutional matters that had not already been raised before the Board. The rationale for this is that since the NEB has the jurisdiction to consider constitutional matters, any effort to raise new questions would inappropriately bypass the Board.[32] In this application for leave to file evidence, Justice Stratas noted that most of the affidavits "bear upon the issue whether there was a duty to consult".[33]

Justice Stratas permitted the affidavits to be filed but left their ultimate admissibility to be determined by the panel hearing the matter. While he was unclear as to the extent to which the affidavits might have been raising new constitutional issues, Justice Stratas was referred to several authorities suggesting that the courts had taken a more relaxed view concerning the admissibility of new evidence in cases concerning Aboriginal peoples.[34] While by no means convinced as to this line of reasoning, Justice Stratas acknowledged that this particular issue had not previously been considered by the Court of Appeal.[35] Similarly, Justice Stratas also left to the hearing panel the question of whether the test for the admissibility of fresh evidence on a statutory appeal under the NEBA was governed by the test set out in *Palmer v The Queen*[36] or by an administrative law standard.[37]

In the third decision, *Gitxaala Nation v Northern Gateway Pipelines Inc*,[38] Justice Stratas was called upon to rule on two contested applications to intervene, one from Amnesty International (Amnesty) in support of the appellants and a second from the Canadian Association of Petroleum Producers (CAPP) in support of the respondents. Justice Stratas considered both applications in light his own decision in *Canada (Attorney General) v Pictou Landing First Nation*,[39] which set out this test:[40]

> I. Has the proposed intervener complied with the specific procedural requirements in Rule 109(2)? Is the evidence offered in support detailed and well-particularized? If the answer to either of these questions is no, the

28 *Bankes*, *supra* note 26.
29 This section draws on material previously posted on ABlawg as, "An Update on the Northern Gateway Litigation" and available online: <http://ablawg.ca/wp-content/uploads/2015/03/Blog_NB_NGP_March2015.pdf>.
30 *Forest Ethics Advocacy Association v Gateway Pipelines Inc,* 2015 FCA 26.
31 *Gitxaala Nation v Canada,* 2015 FCA 27.
32 See the discussion of this issue *infra* in the context of Enbridge's Line 9B application.
33 2015 FCA 27, at para 8.
34 *Chartrand v The District Manager*, 2013 BCSC 1068; *Tsuu T'ina Nation v Alberta (Environment)*, 2008 ABQB 547, aff'd 2010 ABCA 137; *Enge v Mandeville*, 2013 NWTSC 33; and *Pimicikamak Band v Manitoba*, 2014 MBQB 143.
35 2015 FCA 27 at para 10.
36 *Palmer v The Queen*, [1980] 1 SCR 759.
37 *Gitxaala Nation v Canada, supra* note 31at paras 11–13.
38 *Gitxaala Nation v Canada,* 2015 FCA 73 [*Amnesty*].
39 *Canada (Attorney General) v Pictou Landing First Nation,* 2014 FCA 21 at para 11.
40 *Amnesty, supra* note 38 at para 5.

> Court cannot adequately assess the remaining considerations and so it must deny intervener status. If the answer to both of these questions is yes, the Court can adequately assess the remaining considerations and assess whether, on balance, intervener status should be granted.
>
> II. Does the proposed intervener have a genuine interest in the matter before the Court such that the Court can be assured that the proposed intervener has the necessary knowledge, skills and resources and will dedicate them to the matter before the Court?
>
> III. In participating in this appeal in the way it proposes, will the proposed intervener advance different and valuable insights and perspectives that will actually further the Court's determination of the matter?
>
> IV. Is it in the interests of justice that intervention be permitted? For example, has the matter assumed such a public, important and complex dimension that the Court needs to be exposed to perspectives beyond those offered by the particular parties before the Court? Has the proposed intervener been involved in earlier proceedings in the matter?
>
> V. Is the proposed intervention inconsistent with the imperatives in Rule 3, namely securing "the just, most expeditious and least expensive determination of every proceeding on its merits"? Are there terms that should be attached to the intervention that would advance the imperatives in Rule 3?

Amnesty proposed to focus on international law issues as part of its intervention. Justice Stratas granted Amnesty's application on terms. In doing so he took the view that the intervention "casts things too broadly" insofar as it suggests "that international law is very much at large on all issues in many different ways".[41] In his view, international law might be relevant to the matter at hand in one of two ways. First, if there are multiple possible interpretations of a legislative provision the court should prefer an interpretation that would not put Canada in breach of its international obligations. Second, international law might also be relevant with respect to the exercise of a discretionary power – although in that context it would likely be necessary to show that the failure of the statutory decision maker to follow the guidance of international law would be unreasonable:[42]

> That failure may or may not render the decision unreasonable. Much will depend on the importance of the international law standard in the context of the particular case and the breadth of the margin of appreciation or range of acceptability and defensibility the decision-maker enjoys in interpreting and applying the legislative provision authorizing its decision: see, *e.g.*, *Canada (Minister of Transport Infrastructure and Communities) v Jagjit Singh Farwaha*, 2014 FCA 56 at paragraphs 88-105.

While these are simply two situations in which international law might be relevant to the application of domestic law rather than an exhaustive statement of the relevance of international law, they do serve as a reminder to counsel that it is not enough to adduce a body of international law; it is also necessary to show how that body of law might make a difference in terms of outcome.

Justice Stratas was especially cautious with respect to the connection between the duty to consult and accommodate and international law. Here Justice Stratas observed that:[43]

> In the case of the duty to consult, decisions of the Supreme Court are binding on us and have defined the duty with some particularity. We are not free to modify the Supreme Court's law on the basis

41 *Ibid* at para 11.
42 *Ibid* at para 18.
43 *Ibid* at para 19.

> of international law submissions made to us. International law, at best, might be of limited assistance in interpreting and applying the law set out by Supreme Court.

But even with this restriction, there should be considerable opportunity to argue that international law might inform such matters as: the content of the duty to consult, the significance of the right to culture, the respect that should be accorded to indigenous conceptions of property, and the question of what might constitute an unjustifiable infringement of an aboriginal right or title or a treaty right.[44]

Justice Stratas summarized his instructions to counsel as follows:[45]

> Amnesty International's written and oral submissions shall be limited to issues of international law, but only insofar as they are relevant and necessary to any of the issues in the consolidated matter. It must explain, in legal terms, how and why the particular international law submission is relevant and necessary to the determination of a specific issue, with specific reference to the law set out above or other law bearing on the point. For example, it will have to identify a legislative provision that is ambiguous or that authorizes more than one exercise of discretion and then identify the international law that it says is relevant to the issue.

Justice Stratas also invited counsel for the respondent to consider whether it might need to apply to extend the approved length of its memorandum of fact and law once it had had the opportunity to review the intervenor's arguments.[46] Justice Stratas had rejected an earlier application from Enbridge to file a more extensive memorandum.[47]

In some respects, CAPP's application to intervene seemed to present more difficulty than that posed by Amnesty's application. After all, as Justice Stratas himself acknowledged:[48]

> The Association appears to be doing nothing more than advancing submissions that the respondents can themselves advance. The submissions do not reflect any particular perspective of the Association, a group of entities whose economic interests are affected by the Northern Gateway Pipeline Project.

What then were the clinching factors here that justified allowing CAPP to intervene (again on terms)? Justice Stratas referred to three considerations. First, the Court acknowledged that the decision to approve the project had involved public interest considerations (or

44 See my post on the Supreme Court of Canada's decision in *Grassy Narrows First Nation v Ontario (Natural Resources)*, 2014 SCC 48, "Grassy Narrows, Division of Powers and International Law", online: ABlawg<http://ablawg.ca/2014/08/06/grassy-narrows-division-of-powers-and-international-law/>; and for more extensive discussions of the relevant treaty texts and the literature see Nigel Bankes, "Indigenous land and resource rights in the jurisprudence of the Inter American Court of Human Rights: comparisons with the draft Nordic Saami Convention" (2011), 54 German Yearbook of International Law 231 – 280, "The protection of the rights of indigenous peoples to territory through the property rights provisions of international regional human rights instruments" (2011) 3 Yearbook of Polar Law 57 – 112, and "International human rights law and natural resources projects within the traditional territories of indigenous peoples" (2009), 47 Alberta Law Review 457 - 495.

45 *Amnesty, supra* note 38 at para 27.

46 *Ibid* at para 30.

47 *Forest Ethics Advocacy Association v Canada,* 2014 FCA 182 at para 26.

48 *Amnesty, supra* note 38 at para 32. And compare *Forest Ethics Advocacy Association and Donna Sinclair v National Energy Board and AG Canada*, 2013 FCA 236; notwithstanding the style of cause, this decision (which deals with Line 9B, see further discussion below) deals inter alia with an application from Valero Inc to intervene in support of Enbridge's application. Valero was an intervenor in the Board proceedings and sought permission either to be added as a respondent or to intervene in the judicial review application. Valero grounded its claim on the basis that it had entered into transportation services contract (TSC) with Enbridge to secure transport for western Canadian crude oil for its refinery. Justice Stratas rejected both alternatives. Justice Stratas held (at para 26) that Valero's interest under the TSC was too consequential, indirect or contingent to fall within a "direct effect" test for the purposes of being joined as a respondent. But neither did Valero deserve to be permitted to intervene because it had failed (at paras 37 – 39) to articulate how its interest as a refiner differed from Enbridge's interest as a pipeline builder.

public convenience and necessity in the argot of the *NEBA*) and that "The Association is well-placed to speak to the issue of public interest. It represents a broad segment of the public affected by the decision below."[49] The second relevant consideration seems to have been "equality of arms" (i.e. the need for "overall fairness in the litigation process").[50] And finally Justice Stratas noted that CAPP had been significantly involved in the matter under review. But Justice Stratas also had advice and instructions for counsel to CAPP:[51]

> [CAPP] shall make representations on the public interest considerations that come to bear on this Court's assessment of the correctness or reasonableness of the decisions under review. If reasonableness review is relevant, submissions may be made on the size or nature of the range of acceptability or defensibility or the margin of appreciation that should apply to the decisions under review and whether the decisions under review are within those ranges or margins. To be clear, the draft memorandum it has presented to this Court does not comply with the requirements set out in this paragraph and will have to be amended.

Enbridge Line 9B

Line 9 connects Sarnia and Montreal. It was originally constructed by Interprovincial Pipeline Inc (now Enbridge) in the mid-1970s as part of the Government of Canada's response to the OPEC crisis to permit the delivery of Canadian oil to refineries in Montreal. In 1997 IPL obtained and implemented NEB approval to reverse Line 9 to permit shipment of oil from Montreal to refineries in Ontario. There matters stood until 2011 when Enbridge applied to reverse (i.e. reinstate an easterly flow) from Sarmia to North Westover (west of Toronto). This (Line 9 Reversal Phase I) took effect in 2013 but prior to that Enbridge made the further 9B application to reverse the balance of Line 9 into Montreal and to increase the capacity of the entire line from 240,000bpd to 333,333bpd. The Board issued its reasons for decision recommending approval of this application in March 2014.[52]

There are two cases involving Line 9B. The first was a judicial review application commenced by Forest Ethics Advocacy Association and Donna Sinclair. The Federal Court of Appeal provided a reasoned decision on this application in December 2014.[53] The second application was an application for leave to appeal commenced by the Chippewas of the Thames First Nation. The Court has granted leave on issues that include the Crown's duty to consult and accommodate.[54]

The Forest Ethics Case

As noted above, the Forest Ethics\Sinclair application was a judicial review application in respect of three interlocutory decisions.[55] First, the Board had ruled that it would not consider the environmental and socio-economic effects associated with upstream activities, the development of the Alberta oil sands, and the downstream use of oil transported by the pipeline. The applicants contended that this decision was unreasonable. Second, the Board assessed (and rejected) the standing of the applicants to participate in the proceeding on the basis of an Application to Participate Form. Third, the applicants, and specifically Ms. Sinclair, argued that the Board had denied Ms. Sinclair her freedom of expression under the Charter by denying her standing. The Court also considered whether the applicants were in a position to raise Charter questions before the Court if such questions had not been raised before the Board; it also considered whether Forest Ethics had standing before the Court on

49 *Amnesty, supra* note 38 at para 34.
50 *Ibid* at paras 23, 36, referencing Lord Woolf, *Access to Justice: Interim Report to the Lord Chancellor on the Civil Justice System in England and Wales* (London, UK: Lord Chancellor's Department, 1995).
51 *Amnesty, supra* note 38 at para 39.
52 NEB, Reasons for Decision, Enbridge Pipelines Inc, OH-002-2013, March 2014.
53 *Forest Ethics, supra* note 11.
54 Leave granted 4 June 2014, File FCA, A-358-14 (information derived from the NEB's Court Challenges web page, *supra* note 4.
55 My discussion of this case was first published as an Ablawg post at <http://ablawg.ca/2014/11/11/judicial-supervision-of-the-national-energy-board-neb-the-federal-court-of-appeal-defers-to-the-neb-on-key-decisions/>.

the judicial review application.

The Procedure Followed by the NEB in Assessing Standing

S. 55.2 of the *NEBA* establishes two forms of participation rights in relation to an application for a certificate of public convenience and necessity: (1) participation as of right for any person whom the Board considers to be adversely affected, and (2) participation at the discretion of the Board if, in the Board's opinion, the proposed intervener has "relevant information or expertise". The Board's decisions on such matters are "conclusive". In order to assess applications to intervene the Board required potential interveners to complete an Application to Participate Form. The Board granted some parties full intervention rights, granted some the opportunity to submit a letter of concern, and denied others, including Ms. Sinclair, any opportunity to participate further.

The choice of instrument that the Board uses to assess standing is a question of procedure. The standard of review for question of procedure is "correctness with some deference to the Board's choice of procedure".[56] The Court gave several reasons for emphasizing the deference owed to the Board in relation to its choices:[57]

> … in it its process decision, the Board is entitled to a significant margin of appreciation in the circumstances of this case. Several factors support this:
>
> - The Board is master of its own procedure …
> - The Board has considerable experience and expertise in conducting its own hearings and determining who should not participate, who should participate, and how and to what extent. It also has considerable experience and expertise in ensuring that its hearings deal with the issues mandated by the Act in a timely and efficient way.
> - The Board's procedural choices – in particular, the choice here to design a form and require that it be completed – are entitled to deference …
> - The Board must follow the criteria set out in section 55.2 of the Act – whether "in [its] opinion" a person is "directly affected" by the granting or refusing of the application and whether the person has "relevant information or expertise." But these are broad terms that afford the Board a measure of latitude, and so in obtaining information from interested parties concerning these criteria, it should be also given a measure of latitude.
> - Finally …. the Board's decisions are protected by a privative clause. (Authorities omitted)

The Court went on to say that "Board hearings are not an open-line radio show where anyone can dial in and participate. Nor are they a drop-in center for anyone to raise anything, no matter how remote it may be to the Board's task of regulating the construction and operation of oil and gas pipelines."[58] Furthermore, by amending the Act in 2012 to create two categories of participation, Parliament was signaling that procedures need to be more focused and efficient and that, as such, the Board was justified in creating procedure that requires "rigorous demonstration"[59] of the capacity to make a contribution to the Board's consideration of the matter at hand.

The Decision to Deny Ms. Sinclair Standing

The Board's decision to deny Ms. Sinclair standing is "a mix of substance *and* procedure".[60] While admitting a party to participate is ordinarily a matter of procedure (with a standard of review of correctness with deference to the Board's choices) it is evident that in making its decision the Board is also considering questions of materiality and relevance i.e. issues of substance (with a

56 *Forest Ethics, supra* note 11 at para 70.
57 *Ibid* at para 72.
58 *Ibid* at para 76.
59 *Ibid* at para 77.
60 *Ibid* at para 79, emphasis in original.

standard of review of reasonableness). However, "[r]egardless of how we characterize the Board's decision, the Board deserves to be allowed a significant margin of appreciation … The Board engaged in a factual assessment, drawing upon its experience in conducting hearings of this sort and its appreciation of the type of parties that do and do not make useful contributions to its decisions. Matters such as these are within the ken of the Board, not this Court."[61] The Court then offered detailed reasons for finding that the Board's decision to deny Ms. Sinclair standing was reasonable.[62]

The Decision to Deny Forest Ethics Standing on the Judicial Review Application

It appears from the Court of Appeal's judgement that although Forest Ethics was a co-applicant in attacking the Board's three interlocutory decisions it had had no prior involvement in the matters before the Board. It was indeed a classic "busybody".[63]

> Forest Ethics asks this Court to review an administrative decision it had nothing to do with. It did not ask for any relief from the Board. It did not seek any status from the Board. It did not make any representations on any issue before the Board. In particular, it did not make any representations to the Board concerning the three interlocutory decisions.

As such, Forest Ethics was entitled neither to standing as of right nor as a public interest litigant in bringing this judicial review application.

The Charter Questions

While it followed from this last point that Forest Ethics could not raise a Charter challenge, what about Ms. Sinclair? The Court held that while there would be some cases in which an applicant for judicial review would be able to raise a Charter challenge when the applicant had failed to do so before the administrative tribunal, that was not this case. Instead this case was governed by the usual rule and good practice that requires that the tribunal in question be able to express its own expert and contextualized opinion as to the constitutional or Charter question that the applicant seeks to put at issue.[64]

Upstream and Downstream Effects

The Court's reasons for supporting the conclusion of the Board and finding its decision on (ir)relevance of upstream and downstream effects to be reasonable are long but worth quoting given the importance of this issue in a number of different proceedings:[65]

- The Board's main responsibilities under [the NEBA] …include regulating the construction and operation of inter-provincial oil and gas pipelines (see Part III of the Act).
- Nothing in the Act expressly requires the Board to consider larger, general issues such as climate change.
- … in a section 58 application such as this, the Board must consider issues similar to those required by subsection 52(2) of the Act.
- Subsection 52(2) of the Act empowers the Board to have regard to considerations that "to it" appear to be "directly related" to the pipeline and "relevant." The words "to it," the imprecise meaning of the words "directly," "related" and "relevant," the privative clause in section 23 of the Act, and the highly factual and policy nature of relevancy determinations, taken together, widen the margin of appreciation that this Court should afford the Board in its relevancy determination …
- Further, in applying subsection 52(2) of the Act, the Board could reasonably take the view that larger, more general issues

61 *Ibid* at para 82.
62 *Ibid* at para 83.
63 *Ibid* at para 33.
64 *Ibid* at paras 37–59.
65 *Ibid* at para 69. This issue has also been raised in two actions in the TMX hearing (see *infra* note 67).

such as climate change are more likely "directly related" to the environmental effects of facilities and activities upstream and downstream from the pipeline, not the pipeline itself.

- The Board does not regulate upstream and downstream facilities and activities. These facilities and activities require approvals from other regulators. If those facilities and activities are affecting climate change and in a manner that requires action, it is for those regulators to act or, more broadly, for Parliament to act.

- Subsection 52(2) of the Act contains a list of matters that Parliament considered to be relevant …. Each of these is relatively narrow in that it focuses on the pipeline, not upstream or downstream facilities and activities. Paragraph 52(2) (*e*) refers to "any public interest." It was for the Board to interpret that broad phrase. It was open to the Board to consider that the "public interest" somewhat takes its meaning from the preceding paragraphs in subsection 52(2) and the Board's overall mandate in Part III of the Act. Thus, it was open to the Board to consider that the "public interest" mainly relates to the pipeline project itself, not to upstream or downstream facilities and activities. (In this regard, pre-*Dunsmuir* authorities that engaged in correctness review of the meaning of "public interest" or quashed Board decisions for failing to take into account a factor the Court considered relevant are to be regarded with caution …)

- Parliament recently added subsection 52(2) and section 55.2 to the Act in order to empower the Board to regulate the scope of proceedings and parties before it more strictly and rigorously: *Jobs, Growth and Long-term Prosperity Act*, S.C. 2012, c. 19, s. 83. The Board's decision is consistent with this objective. Consistency of a decision with statutory objectives is a badge or indicator of reasonableness ….

- The Board's task was a factually suffused one based on its appreciation of the evidence before it. This tends to widen the margin of appreciation this Court should afford the Board … In my view, the Board's decision was within that margin of appreciation. [case authorities omitted]

In conclusion, the *Forest Ethics* case is important for a number of reasons. First it contains a useful discussion of standard of review issues with respect to a number of different types of decisions that the NEB must make. Second it confirms that a party intending to raise constitutional questions must raise them before the Board and not hold them back for any judicial review application. Third, it offers detailed reasons supporting the Board's position that it need not consider the upstream and downstream greenhouse gas implications of pipeline decisions.

Trans Mountain Expansion Project

The Trans Mountain Expansion Project (TMX) is a proposal to expand the existing Trans Mountain pipeline system between Edmonton, AB and Burnaby, BC. It would include approximately 987 km of new pipeline, new and modified facilities, such as pump stations and tanks, and the reactivation of 193 km of existing pipeline. The Westridge Marine Terminal would also be expanded. New pipeline segments would be added between Edmonton and Hinton, AB, Hargreaves, BC and Darfield, BC and Black Pines, BC and Burnaby, BC. Some existing, but currently deactivated pipeline segments between Hinton, AB and Hargreaves, BC and Darfield and Black Pines, BC would be reactivated. The effect of the expansion will be to increase throughput by nearly 600,000 bbls per day.[66] The proceedings before the NEB are ongoing.

66 From 300,000 bbls\day to 890,000 bbls\day, "Proposed Expansion", online: Trans Mountain <http://www.transmountain.com/proposed-expansion>.

The application has led to litigation in both the Supreme Court of British Columbia and in the Federal Court of Appeal. This section of the paper covers what will be referred to as the Burnaby bylaw litigation. Other issues have also been raised in the context of the TMX application but none has resulted in reasoned decisions from the Courts.[67]

The Burnaby bylaw applicability issues were pursued before the NEB, in the BC Supreme Court, and before the Federal Court of Appeal. Accordingly, the following section discusses the evolution of the bylaw dispute chronologically rather than strictly separating the two pathways.

TMPL's expansion application anticipates using an existing right of way but open-houses that TMPL conducted in Burnaby, BC as part of preparing its application encouraged it to investigate an alternative and more direct routing in the Burnaby area which would involve drilling through Burnaby Mountain. In order to investigate the feasibility of that alternative TMPL needed to do further studies and assessments, including geotechnical investigations that would require drilling bore holes at particular sites. TMPL attempted to obtain access to the sites in question from the City of Burnaby over a prolonged period but was unable to secure Burnaby's consent to its operations. In response to that TMPL sought clarification from the NEB as to its position under s. 73 of the *NEBA* which provides that:

> A company may, for the purposes of its undertaking, subject to this Act …
>
> (*a*) enter into and on any Crown land without previous licence therefor, or into or on the land of any person, lying in the intended route of its pipeline, and make surveys, examinations or other necessary arrangements on the land for fixing the site of the pipeline, and set out and ascertain such parts of the land as are necessary and proper for the pipeline;

The Board issued its ruling in response on August 19, 2014 in which it stated:[68]

> A plain reading of the language used in paragraph 73(a) provides Trans Mountain with the power to enter any Crown (federal or provincial) or privately owned land which lies in the intended route of its pipeline to make surveys and examinations. There is no requirement in paragraph 73(a) for companies to reach agreement with land owners, the Crown, or otherwise, before exercising the right to access land.

Armed with this ruling TMPL commenced its survey operations only to be met with orders served by the City of Burnaby requiring it to cease operations on the basis that TMPL was in breach of the City's bylaws. TMPL took this issue back to the NEB questioning the constitutional validity or applicability of the bylaws (discussed further below), but in the meantime the City of Burnaby brought an application in the Supreme Court of British Columbia seeking an injunction on the basis of s. 274 of the Community Charter. Justice Brown rejected that application[69] and leave to appeal that decision was also denied.[70]

---

67 The other issues have included *Quarmby v NEB*, FCA 14-A-62 raising Charter issues, leave to appeal to the FCA dismissed without reasons, 23 January 2015, application for leave to appeal was filed with the Supreme Court of Canada, 20 March 2015; *Harvey v NEB*, FCA 14-A-59, raising the relevance of upstream and downstream environmental issues, leave to appeal to FCA dismissed without reasons, 24 October 2014; *City of Vancouver v NEB*, FCA 14-A-55, raising the relevance of upstream and downstream environmental issues, leave to appeal to FCA dismissed without reasons, 16 October 2014; *Tsleil-Waututh Nation v NEB*, FCA A-386-14, duty to consult issues, leave application yet to be heard. All information here from the NEB's website, *supra* note 4.

68 Ruling No. 28, as quoted in *Burnaby (City) v Trans Mountain Pipeline ULC*, 2014 BCSC 1820 and full text available on the NEB's website here <https://docs.neb-one.gc.ca/ll-eng/llisapi.dll?func=ll&objId=2498607&objAction=browse&viewType=1>.

69 *Burnaby (City) v Trans Mountain Pipeline ULC*, 2014 BCSC 1820 [*Burnaby*].

70 *Burnaby (City) v Trans Mountain Pipeline ULC*, 2014 BCCA 465 (leave to appeal denied, per Neilson JA); 2015 BCCA 78 (appeal from the leave decision to a full panel denied). In addition to the litigation commenced by the City of Burnaby the TMPL's activities on Burnaby Mountain also triggered popular protests which resulted in TMPL obtaining an injunction restraining protesters from interfering with its surveying and geotechnical activities: see *Trans Mountain Pipeline ULC v Gold*, 2014 BCSC 2133, 2014 BCSC 2403, 2015 BCSC 242. The most interesting issue

Justice Brown applied the three part test from *RJR-MacDonald Inc. v Canada (Attorney General).*[71] He accepted that there was a serious issue to be tried but clearly believed that the issue should be tried before the NEB rather than by the Supreme Court of British Columbia;[72] the balance of convenience pointed in that same direction;[73] and there was conflicting evidence as to irreparable harm.[74] By the time the matter came before the BC Court of Appeal on a leave application, the NEB had issued its own ruling on the applicability of the Burnaby bylaws (NEB Ruling No. 40[75]) and the Federal Court of Appeal had in turn denied leave (without reasons). As a result, the BC Court of Appeal had little difficulty in concluding that it should not grant leave, both because this should not be entertained insofar as it was a collateral attack on the NEB ruling,[76] but also because the issue, at least in terms of enforcing the by-law, was no longer a live one; TMPL was not contemplating further work on Burnaby Mountain.[77]

As noted in the previous paragraphs, the NEB itself addressed the constitutional validity, applicability and operability of the bylaws in an important ruling, (Ruling No. 40) which in turn was appealed to the Federal Court of Appeal. In the absence of reasons from the Court for its decision to deny leave it is useful to examine the Board's well-reasoned decision. The Board identified three issues that it needed to consider. The first was the legal authority of the Board to consider the constitutional questions of the validity, applicability and operability of the Burnaby bylaws. The Board had little difficulty in confirming that it had this authority and it is clearly on firm ground in reaching this conclusion given that s.11 of the *NEBA* establishes the NEB as a court of record and that s. 12 affords it the "full jurisdiction to hear and determine all matters whether of law or fact".[78]

The second set of issues addressed the core of the matter: validity, applicability and operability. There could be no doubt about the validity of either *NEBA* or Burnaby's bylaws. Indeed the Board hardly mentions the matter although it does go to some efforts in both this ruling and the earlier Ruling No. 28 to establish that the Board's authority to order access to Crown and private lands for the purpose of surveying the route and geotechnical matters is clearly essential to the exercise of the Board's overall jurisdiction.[79] That left the Board to consider the *applicability* of the bylaws (i.e. the issue of inter-jurisdictional immunity) and their

raised in this litigation was the jurisdictional question. Counsel for the protesters argued that the BCSC had no jurisdiction over the matter given the exclusive jurisdiction provisions of the NEBA (ss. 11 - 13). Associate Chief Justice Cullen rejected that argument concluding that TMPL was entitled to seek injunctive relief from the superior courts on the basis of alleged torts that the protesters had committed (at para 70): "what is before this Court is in substance a separate case of tort which arise not 'expressly or inferentially from a statutory scheme' but only incidentally to it." One can infer (at paras 68 – 71) that matters might have been otherwise had the injunction been sought against Burnaby since Burnaby was party to the process before the Board that resulted in NEB Orders 28 and 40 (discussed *infra*), "the present defendants are not". Furthermore we learn in this case (at para 18) that the NEB's Order # 40 had been filed in the Federal Court.

71 *RJR-MacDonald Inc. v. Canada (Attorney General)*, [1994] 1 SCR 311, 111 DLR (4th) 385. In doing so Justice Brown rejected Burnaby's argument to the effect that in a case involving a public authority the Court should presume that the applicant had established irreparable harm and was favoured by the balance of convenience. The Court favoured TMPL's position to the effect that this was a case of competing public interests, local and national (at paras 9, 31).

72 *Burnaby, supra* note 69 at paras 35–41.

73 *Ibid* at paras 51–52.

74 *Ibid* at paras 42–50.

75 *Trans Mountain Pipeline ULC, Notice of Constitutional Question, Reasons for Decision* (23 October 2014), 0H-001-2014 (*Ruling No 40)*, online: NEB <https://docs.neb-one.gc.ca/ll-eng/llisapi.dll/fetch/2000/90464/90552/548311/956726/2392873/2449981/2541380/A97-1_-_Ruling_No._40_-_Trans_Mountain_notice_of_motion_and_Notice_of_Constitutional_Question_dated_26_September_2014_-_A4D6H0.pdf?nodeid=2540944&vernum=-2 > [*Ruling No 40*].

76 *Burnaby (City) v Trans Mountain Pipeline ULC*, 2015 BCCA 78 at para 5. The Court was however careful to leave it open to Burnaby to argue the more general constitutional question as part of its application for a declaration.

77 *Ibid* at para 9.

78 *Ruling No 40, supra* note 75 at 6–8. The relevant authorities cited by the Board in its reasons include *Cuddy Chicks Ltd v Ontario (Labour Relations Board)*, [1991] 2 SCR 5, and *Westcoast Energy Inc v Canada*, [1988] 1 SCR 322. Other authorities supporting this conclusion include *Rio Tinto Alcan Inc. v Carrier Sekani Tribal Council*, 2010 SCC 43 as well as the BC Court of Appeal's decision, *supra* note 70.

79 *Ruling No 40, supra* note 75 at 11–12.

operability (i.e. were the by-laws inconsistent with the provisions of the *NEBA* and thereby inoperable by virtue of the doctrine of paramountcy).

On the issue of operability\paramountcy the Board found that there was a clear operational conflict (within the meaning of the relevant authorities[80]) between the *NEBA* at s .73(a) and the impugned bylaws and that s.73(a) of the *NEBA* must prevail to the extent of that conflict thereby rendering those bylaws inoperable to that extent:[81]

> In the Board's view there is a clear conflict between the Parks Bylaw and paragraph 73(a) of the NEB Act. Section 5 of the Parks Bylaw states that "no person shall cut, break, injure, damage, deface, destroy, foul or pollute any personal property or any tree, shrub, plant, turf or flower in or on any park". There is a clear prohibition against cutting any tree, clearing vegetation or boring into the ground, regardless of whether minimal tree clearing is necessary where the trees would create a safety risk for the drilling work that must occur. While the Board accepts that the Parks Bylaw has an environmental purpose, the application of the bylaws and the presence of Burnaby employees in the work safety zone had the effect of frustrating the federal purpose of the NEB Act to obtain necessary information for the Board to make a recommendation under section 52 of the NEB Act.
>
> There is also an operational conflict with sections 24(1) and (4) of the Traffic Bylaw. While 24(1) does allow Burnaby Council to approve work along a highway or to impose conditions regarding such work, in this case the Board finds that Burnaby refused to consider Trans Mountain's request. ... [G]iven the refusal of Burnaby to discuss the work, Trans Mountain undertook this work on its own. ...

In the Board's view, there is an operational conflict between the Impugned Bylaws and federal law. Based on the facts before the Board, dual compliance is impossible.

As for the doctrine of inapplicability or inter-jurisdictional immunity, the Board correctly recognized that this doctrine has to some extent fallen out of favour in recent years[82] but also recognized that it has some continued relevance especially with respect to some recognized categories of provincial laws.[83] The doctrine applies to render inapplicable an otherwise valid provincial law where that provincial law impairs the core content of a federal head of power. The Board concluded that both elements of the test (core competence and impairment) were met and that therefore, and in the alternative to the paramountcy argument, the impugned bylaws must be "inapplicable to the extent they impair temporary access to the Subject Lands by Trans Mountain for the purposes set out in paragraph 73(a)."[84]

The third and fourth issues raised questions as to the ability of the Board to operationalize the above conclusions with respect to the main issues. Here the Board concluded that it could issue an order against Burnaby forbidding the City from applying its bylaws in such a way as to prevent TMPL from exercising its powers under s. 73(a) of the *NEBA*.[85] It also concluded

80 The authorities include *Canadian Western Bank v Alberta*, 2007 SCC 22, [2007] 2 SCR 3 [*Canadian Western Bank*]; *British Columbia (Attorney General) v Lafarge Inc*, 2007 SCC 23, [2007] SCR 86; *Bank of Montreal v Hall*, [1990] 1 SCR 121, 65 DLR (4th) 361; *Multiple Access v McCutcheon*, [1982] 2 SCR 161, 138 DLR (3d) 1.

81 *Ruling No 40, supra* note 75 at 12–13.

82 Not least with respect to s. 91(24), Indians and Lands Reserved for Indians. See *Tsilhqot'in First Nation v British Columbia*, 2014 SCC 44, [2014] 2 SCR 256, and for comments see Nigel Bankes, "The implications of the *Tsilhqot'in* (William) and *Grassy Narrows* (Keewatin) decisions of the Supreme Court of Canada for the natural resources industries" Journal of Energy and Natural Resources Law (2015), online: <http://www.tandfonline.com/doi/full/10.1080/02646811.2015.1030916>.

83 See *Canadian Western Bank, supra* note 80.

84 *Ruling No 40, supra* note 75 at 15.

85 *Ibid* at 17.

that the facts, and in particular the City's refusal to cooperate, provided compelling reasons for issuing the order.[86]

The Board's methodology and reasoning here is compelling and offers useful guidance for thinking about the interaction of federal pipeline law and provincial environmental legislation.[87] Both will be valid and in most cases a pipeline operator will need to comply with both the provincial laws and the *NEBA* – but there will be some cases in which the provincial law will frustrate the attainment of federal objective and such a law will be either inoperative or inapplicable. It is unfortunate that the Federal Court of Appeal declined to provide its own reasons for denying leave to appeal on such an important legal question but perhaps this was a case in which the Board's own reasons required no further judicial glossing.

TransCanada Energy East

Energy East involves converting existing natural gas pipeline segments between the Alberta\Saskatchewan border and the Ottawa area to oil transportation; constructing new pipeline primarily in Alberta, Québec and New Brunswick to link up with the converted pipe; and constructing associated facilities, pump stations and tank terminals required to move crude oil from Alberta to Québec and New Brunswick, including marine facilities. At the time of writing, the Board had yet to establish a schedule of hearing dates and locations.

Thus far the main litigation launched against the Energy East project[88] involved an application brought by *Centre québécois du droit de l'environnement*[89] (CQDE) in the Federal Court Trial Division for an interlocutory injunction to extend any deadlines for participating in the Board's consideration of TCPL's application until the Commissioner for Official Languages had ruled on a complaint filed with the Commissioner by CQDE in which CQDE sought a direction that the NEB provide an official translation of the entirety of the 23,000 page Energy East application. Justice de Montigny dismissed the application on both jurisdictional and substantive grounds. On the jurisdictional issue, Justice de Montigny ruled that the Federal Court Trial Division had no appellate or judicial review jurisdiction over the NEB for the reasons rehearsed above and that it could not obtain this jurisdiction by virtue of the *Official Languages Act (OLA)*:[90]

> To the extent that the purpose of the interlocutory injunction motion brought by the moving parties is essentially to challenge the ruling rendered by the Board ... it seems clear to me that this Court is not the appropriate forum and that the procedural vehicle chosen is inappropriate. It goes without saying that it would be wrong to do indirectly what is not permitted directly. The appropriate way for the moving parties to request a stay of the proceedings before the Board was to challenge the Board's ruling ... before the Federal Court of Appeal, the only Court that has jurisdiction to entertain an appeal from a ruling of the Board, and to request, by means of a crossmotion, the stay of proceedings before the Board for the duration of the challenge.

On the substantive issue, Justice de Montigny noted that CQDE would need to establish "that their future proceeding under the *OLA* raises a serious question, that they will suffer irreparable harm in the event that their motion is dismissed, and that the balance of convenience lies in their favour."[91] Justice de Montigny was of the view that CQDE's position had no merit. While it was clear that the *OLA* applied to the NEB, all that the *OLA* requires is " 'optional unilingualism' at the option of the speaker .... Put differently, it is the right to use either official language in any

86 *Ibid* at 17–18.

87 For a discussion about the applicability of provincial environmental assessment legislation to NEB-regulated pipelines, see Martin Olszynski, "Whose (Pipe)line is it Anyway?" available online: ABLawg <http://ablawg.ca/2014/12/03/whose-pipeline-is-it-anyway/>.

88 See also Council of Canadians v NEB, FCA 14-A-32, asking the NEB to set down a list of issues, application of leave to appeal denied, no standing, 25 July 2014, as per the Board's website, *supra* note 4.

89 *Centre qubécois du droit de l'environnement*, *supra* note 12.

90 *Ibid* at 6.

91 *Ibid* at 9.

court or in any pleading in or process issuing from any such court that is guaranteed, and not the right that the official language used will be understood by the person to whom the pleading or process is addressed ...".[92]

> In the absence of a clear legislative provision to that effect, there cannot be an obligation as onerous as that of requiring that all administrative tribunals and all courts subject to the *OLA* have all of the records submitted to them translated. In the alternative, the moving parties maintained that they could also avail themselves of section12 of the *OLA*, which sets out that "[a]ll instruments directed to or intended for the notice of the public, purporting to be made or issued by or under the authority of a federal institution, shall be made or issued in both official languages". However, that provision clearly does not apply in this case because the application filed by Energy East did not originate from the Board.[93]

Justice de Montigny went on to note that the *OLA* might not exhaust the possible claims that the applicants might have. In particular he observed that if Energy East (or the NEB) failed to provide sufficient documentation in both official languages so as to permit a party to understand the issues raised in the application and to make an informed judgement as to whether or not to seek to participate, then a party might be able to bring an application before the Federal Court of Appeal on procedural fairness grounds.[94]

The CQDE case is principally important as an illustration of the different types of arguments that energy proponents must expect to meet in developing new projects. The case also confirms that the trial division of the Federal Court has no role to play in supervising the NEB; that duty falls to the Federal Court of Appeal.

Conclusions

Our current energy paradigm is highly networked and requires large linear developments. This survey of current applications before the NEB confirms that new linear developments will be contentious both at the site-specific level (Burnaby Mountain) and at a more macro-level (the carbon lock-in effects of new pipeline infrastructure), and will bring in to play competing assessments of the public interest (nationally and locally). This survey also shows that these contesting interests will throw up a broad range of questions. The issues canvassed here include constitutional questions (language rights, division of powers issues, aboriginal rights and the Charter), international law issues, technical questions of administrative law including the jurisdiction of the Federal Court, the Federal Court of Appeal and provincial superior Courts as well as questions of standing, and more traditional environmental law issues.

Many of the cases canvassed here are interlocutory in nature with the merits still to be heard. While all of these cases deserve monitoring it will be particularly important to follow the Northern Gateway litigation to see what it tells us about the relationship between the Courts, the NEB and the Governor in Council. Stay tuned. ■

92 *Ibid* at 9–10 (authorities omitted).

93 *Ibid* at 11.

94 *Ibid* at 12–13. The Court went on to note that the applicants had not established irreparable harm or even prejudice at this stage in the proceedings and that therefore the balance of convenience favored allowing the Board's process to proceed without interruption (*Ibid* at 13 – 14).