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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.

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Rowland J. Harrison, Q.C. and Gordon E. Kaiser
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Canadian energy policy and regulation are currently dominated by measures to address climate change and by the scope of participation in review processes for proposed new energy infrastructure projects. The two issues are directly related, inasmuch as the demands of many groups and communities for a direct role in decision-making on specific projects are often motivated by their views on climate change. This issue of *Energy Regulation Quarterly* includes significant contributions to the public debate around both issues.

The concept of "social licence" has, over only a few years, come to play a dominant role in virtually every public review process for energy infrastructure projects. Notwithstanding the lack of understanding of exactly what the term means, it has been elevated to the status of an absolute rule – *a sine qua non* or absolute precondition – for project approvals. But, when it comes to decision time on individual projects, where tension between local and broader national interests is inevitable, what does it mean to say: "While governments grant permits for resource development, only communities can grant permission."[1]

How to balance local and national interests is a significant challenge, particularly in Canada with its wide diversity of regional and Indigenous interests and its vast geography. The lead article in this issue of *ERQ* on "A Matter of Trust: The role of communities in Energy Decision-Making", by Michael Cleland (with others), is an important contribution to meeting this challenge by identifying and analyzing some of the dynamics. The article is based on the results of new research from the University of Ottawa and the Canada West Foundation showing that the nature of local opposition, and the underlying concerns, are often not what opinion leaders and political decision-makers have assumed.

To date, policy and regulatory measures to address climate change have been initiated from province to province. We say "to date" because, as this issue of *ERQ* was closing, the focus shifted somewhat to the federal government with the Prime Minister's controversial announcement on October 3 of a proposed national price on carbon.[2] Provincial initiatives on climate change will, however, continue to play a primary, frontline role that the provinces are unlikely to cede. It is particularly timely, therefore, that this issue of *ERQ* includes "An Overview of Various Provincial Climate Change Policies Across Canada and Their Impact on Renewable Energy Regulation," by several lawyers from Blake, Cassels and Graydon LLP, led by Dufferin Harper.

As is apparent from this overview article, policy and regulatory approaches to addressing climate change vary and all present their own challenges. Jason Kroft and Sam Dukesz offer their observations on one particular model in "Cap and Trade in Ontario: Lessons from Europe."

In their article on "Renewables and Alberta's Electricity Markets: Some European Learnings", Kalyan Dasgupta and Simon Ede (with Leonard Waverman) also draw on European experience in discussing the role of renewable energy markets in decarbonisation policies, such as Alberta's Climate Leadership Plan.

Ian Mondrow's article on "Competition in Electricity Transmission: Two Canadian Experiments" reviews tentative initiatives in Ontario and Alberta to introduce competition into electricity transmission. It is no coincidence, he observes, that the two Canadian jurisdictions

1 Liberal Party of Canada, *Environmental Assessments*, online: <https://www.liberal.ca/realchange/environmental-assessments/>.
2 Prime Minister of Canada, *Prime Minister Trudeau delivers a speech on pricing carbon pollution* (Ottawa: 3 October 2016), online: <http://pm.gc.ca/eng/news/2016/10/03/prime-minister-trudeau-delivers-speech-pricing-carbon-pollution>.

with aspirations to develop competitive electricity markets have found a way to introduce competition into the development of new transmission infrastructure, with the result that "transmission competition" is no longer an oxymoron.

In their article "A Requiem for the Presumption of Prudence after *OPG* and *ATCO*", Venessa Korzan and Moin Yahya conclude that, in two recent decisions, the Supreme Court of Canada has freed up regulators to review costs, regardless of whether they were incurred or forecasted, utilizing whichever statutorily compliant and reasonable test the regulator chose. The once popular view that forecasted costs should be reviewed by regulators under a forward looking 'onus of proof on the utility' reasonableness test, while already incurred costs should be reviewed under a presumption of prudence test, is no longer valid.

Martin Ignasiak, Jessica Kennedy and Justin Fontaine provide a case comment on a recent decision by the Alberta Utilities Commission confirming that it has no jurisdiction to consider or assess the adequacy of Crown consultation with Aboriginal groups that may be affected by a project under review. The ruling, they conclude, will help guide the scope of future facilities proceedings before the AUC. ■

A MATTER OF TRUST: THE ROLE OF COMMUNITIES IN ENERGY DECISION-MAKING

*Michael Cleland**

Introduction

Energy development sometimes faces powerful local opposition in communities across Canada. Energy companies have found themselves under the microscope and regulators have been forced to confront their evolving role in this new context. New research from the University of Ottawa and the Canada West Foundation shows, however, that the nature of this opposition, and the underlying concerns, are often not what opinion leaders and political decision-makers have assumed. Importantly, local opposition is not restricted to pipelines and oil sands, and it is often not about climate change.

This article is derived from the second and final report of a project designed to better understand what drives community confidence in energy project decision-making processes. The project aimed to develop a better understanding of the relationship between local communities and public authorities in energy development; identify reasons for shortcomings respecting trust and confidence; and develop ideas for restoring trust and confidence.

Two closely linked research questions were explored in the study:

- What are the factors that lead to greater satisfaction in local communities with the energy infrastructure siting process? and
- What is the level of local community confidence in the actions of public authorities towards new energy infrastructure?

The project arose from one primary observation: that the growing national debate about confidence in energy project decision-making processes has too few voices from local communities themselves. In other words, while many local communities are raising concerns about specific projects, those concerns are not necessarily being translated into broad insights or conclusions that could be applied across other projects or communities. There is also much talk and conjecture about what communities think, why they respond in particular ways to energy project decision-making processes, and the role of regulators, proponents, policy-makers, local leaders and local or regional and national NGOs in the process. There is relatively limited empirical knowledge of what happens on the ground in communities. Given this, we set out to undertake a series of community-level case studies.

Approach and Methodology

The preliminary research undertaken in advance of the detailed case study research was captured in an interim report entitled: *Fair Enough: Assessing Community Confidence in Energy Authorities.*[1] It drew on a series of interviews with energy leaders across the country and a review of academic literature to establish the analytical foundation for the case studies. The case studies were assessed

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1 Michael Cleland & al, *Fair Enough: Assessing Community Confidence in Energy Authorities* (Ottawa: Canada West Foundation and University of Ottawa, 2016).

by a combination of semi-structured interviews (86 in total across the six communities), and by telephone surveys reaching 1795 residents between July 26 to September 7, 2016 in four of the target communities.[2] Details on research design and methods can be found in the final report (A Matter of Trust: The Role of Communities in Energy Decision-Making).[3]

The concepts of trust and confidence ran through all the literature (Nourallah, 2016)[4] and the vast majority of the senior level interviews. By itself, however, the lack of trust and confidence tells us little about what to do. More tractable insights can be found by projecting our understanding through the further lens of "fairness" and organizing our approach to that term under four dimensions as outlined below. The analysis of the six community case studies that are discussed in this article is organized as such.

See table below.

The findings – organized around the above concepts and briefly outlined below – tell the story of residents, mainly in small or rural communities, and their experience with regulatory processes.

Our research shows plainly that opposition to energy projects in Canada extends well beyond the oil sands and associated pipelines, to various types of energy projects. A number of our case studies look at electricity projects – a power line, a hydroelectric dam, gas-fired power plants and a wind farm. Some were approved and some were not. Some were built with community support and some over the protest of communities.

Also, while many decision-makers continue to assume that concerns about climate change drive local opposition, our research shows that this is not the case. Other factors have emerged as being far more important, including: safety, need, distribution of benefits, local environmental impacts (e.g., water contamination), restrictive consultation/communication practices, and lack of local involvement in decision-making.

From shale gas exploration on the East Coast to wind farms in central Canada to a proposed pipeline terminus on the West Coast, local authorities and communities are demanding an increasing role in how economic and environmental decisions by third parties affect their future. One thing seems very clear – the world of elite, centralized decision-making with minimal local engagement is fast becoming a thing of the past.

It is difficult to capture the insights from six diverse case studies in a few words, and attention to the case study synopses will be rewarding but in the briefest of terms we can make the following observations:

Dimensions contributing to trust and confidence	**Key characteristics**
Context	The nature of the community and the project, important external influences, including experience elsewhere and the planning and regulatory frameworks.
Values and interests	Multiple and often contradictory. Perceptions of costs, benefits and risks. Negotiable and non-negotiable aspects.
Information and capacity	Public use of, and trust in, the information underlying the decision-making process. Ability to gain and use appropriate information.
Engagement and participation in the decision-making process	The opportunity for the public to meaningfully participate in, and influence, decisions.

2 Two of the communities, Nisichawayasihk Cree Nation (NCN), Manitoba and St-Valentin, Québec had inadequate population from which to draw a statistically significant sample and there is, therefore, no quantitative data for those communities.
3 Michael Cleland & al, *A Matter of Trust: The Role of Communities in Energy Decision-Making,* (Ottawa: University of Ottawa and Canada West Foundation, October 2016) [Forthcoming].
4 Laura Nourallah, *Communities in Perspective: The Dimensions of Social Acceptance for Energy Development and the Role of Trust, Positive Energy Project* (Ottawa: University of Ottawa, 2016).

- **Context matters.** In all the case studies, various contextual factors governed the degree of community confidence in the process and outcome. Key factors include legacy experiences with past projects and the local and rural culture that creates a context in which the energy project and regulatory process are inherently intrusive. We need to build flexibility and understanding into processes to respond to diverse realities.

- **Interests, while important, played a secondary role to values.** Negotiable factors, such as jobs, community investment and resource rents, mattered but in most cases were secondary compared to values. There are cases where deeply held values – such as a rural environment, clean air or simply the importance of being treated openly and fairly – dominate community views. It is clear that speaking to economic interests alone will not shake people from these values.

- **Information matters but energy literacy is not the issue.** Broadly speaking, the case study communities acted to inform themselves and approached the issues with some measure of objectivity, but the timing, channels, sources, and the nature and quality of the information affected community confidence in the decision-making process. While there is no ideal information strategy, "information about information" – who has it, where it is, how one gets it – matters from the outset.

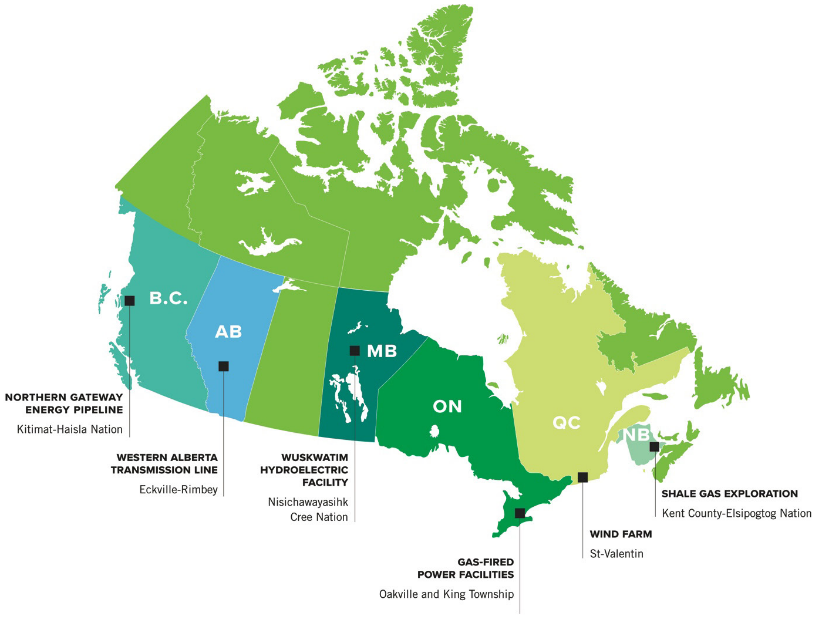
- **Engagement has to be real and early in the process.** Across the six cases, engagement took many different forms but came up short in several respects. Engaging the community should be about more than notices and a few town hall meetings. It should involve real consultation with the possibility that plans may change. Going further, it can involve true collaboration with the community acquiring a substantive role in the process and even a direct stake in the project.

Case studies examined in table below.

The Case Studies

Project and Community	Approved or not, built or not (if built, when)	Primary jurisdiction responsible	Linear / regional / local	Power / fuel; fossil / renewable
Northern Gateway Energy Pipeline – Kitimat and Haisla Nation, British Columbia	Approved but not (yet) built	Federal government	Linear	Fuel transport; fossil
Western Alberta Transmission Line (WATL) – Eckville-Rimbey, Alberta	Approved, built and in service December 2015	Alberta provincial government	Linear	Power transmission; fossil and renewable
Wuskwatim hydro-electric facility – Nisichawayasihk Cree Nation (NCN), Manitoba	Approved, built and in service June 2012	Manitoba provincial government	Local	Power; renewable
Urban natural gas power stations – Oakville and King Township, Ontario	Oakville – not approved King – approved, and in service May 2012	Ontario provincial government	Local	Power; fossil
Wind farm – St-Valentin, Québec	Not approved	Québec provincial government	Local / regional	Power; renewable
Shale gas exploration –Kent County and Elsipogtog Nation, New Brunswick	Not approved	New Brunswick provincial government	Regional	Fuel; fossil

Community Case Studies: Quick Reference Guide



Northern Gateway Energy Pipeline – Kitimat and Haisla Nation, B.C.

Northern Gateway is the name given by its sponsor Enbridge to a proposal for a pipeline linking Bruderheim, Alta., and Kitimat, B.C., to carry 525,000 barrels a day of diluted bitumen. If built, the pipeline would traverse 1,176 kilometres, mainly in northern B.C., touching on the territories of more than 50 Indigenous groups in northwestern B.C. The delivered product would be transshipped onto oil tankers at the deep-water port of Kitimat and the tankers in turn would traverse the Douglas Channel before reaching open water.

The principal regulatory authority in this case was the National Energy Board, which established and implemented a Joint Review Panel (JRP) under the authority of both the *NEB Act*[5] and the *Canadian Environmental Assessment Act* (*CEAA*)[6].

The project became one of the most controversial energy projects in Canada in recent years. It faced opposition at various stages from its inception through the regulatory (Joint Review Panel) process, and from different groups, including many ENGOs (Environmental Non-Governmental Organizations), Indigenous communities and residents in communities affected by the project. Despite receiving conditional approval from the JRP, the project has not gone forward. Its future prospects are heavily clouded by a proposed federal ban on tanker traffic on the north coast of B.C. and a June 2016 court ruling that the government did not meet its duty to consult with affected Indigenous groups.

Key observations:

- It was apparent in the interviews and polling that the community was split on the project. One in two of the polled Kitimat residents support or somewhat support the Northern Gateway project, while two in five oppose or somewhat

5 *National Energy Board Act*, RSC 1985, c N-7.
6 *Canadian Environmental Assessment Act*, SC 2012, c 19.

oppose it.

- Concerns in the affected communities covered by this case study (Kitimat and the Haisla Nation) centred on safety and spill risk. Three in four residents agreed or somewhat agreed that the pipeline increases the risk of an accident that could harm the environment in their community and beyond. Other communities along the pipeline route were also concerned about spills, as well as disturbance of relatively untouched wilderness.

- Overall, Kitimat residents had a fairly low level of confidence in public authorities, 54 per cent of polled residents did not trust the regulators to make decisions about energy projects.

- As the opposition to the Northern Gateway project grew, it became about more than just the project. For groups outside the directly affected communities, the project became a vehicle to raise broader issues, such as linking shipment of fossil fuels with climate change.

- The possibility of a refinery changed the discussion in Kitimat. Many in Kitimat thought that, when exporting Canada's resources, it is important to extract as much value and jobs as possible from that commodity. There is a narrative on the West Coast that can be summarized as, "bitumen bad, refined product good."

- In the eyes of the community, both the proponent and the regulator failed on the engagement front. The factors highlighted were the method, timing (not early enough), and lack of genuine engagement with the community.

- One of the biggest failures of this project, identified by project supporters and other interview participants, was the lack of sensitivity to community context and a local voice on the project to advise the proponent and regulators along the way.

Western Alberta Transmission Line (WATL) – Eckville and Rimbey, Alberta

The WATL is a 500 kilovolt direct current (DC) power line between Genesee and Langdon, Alberta. WATL was built and is owned by AltaLink Management Ltd., Alberta's largest regulated electricity transmission company. The initial WATL project application was submitted in 2011. However, the WATL was preceded by AltaLink's North-South transmission project, which was initiated in 2004 and went to Energy and Utility Board (EUB) hearings in 2007. This process was highly controversial and led to eventual suspension of the project; it had an important influence on the attitudes toward the subsequent WATL project.

One unusual aspect of the case was a scandal in 2007. It was revealed that the EUB hired private investigators to eavesdrop on the landowners who were opposed to the North-South transmission project. Coupled with other concerns, the incident damaged the EUB's credibility as an independent quasi-judicial board leading it to be disbanded. The project was marked by shifting regulatory process, institutions, and legislative changes. WATL was eventually approved by the Alberta Utilities Commission (AUC, the successor organization to the EUB) following a new round of hearings, but the controversy over the previous proposal made the project politically charged and eroded some of the provincial government's historic political support in rural areas.

Key observations:

- The single biggest concern landowners had with the project was the decision not to conduct a public needs assessment at the time the project was brought forward. Landowners felt the line was simply unnecessary and therefore not worth the disruption it would create. More than half of the polled residents said a fair needs assessment demonstrating the necessity of the line would have changed their support for the line. After needs, the major concern was the impact of the line on property values and agricultural operations (62 per cent agreed or somewhat agreed).

- There was broad agreement in the interviews that the community and landowners did not trust the regulator to make a fair decision in the public interest of Albertans. There was a general sense that the process was "rigged" from the beginning and the regulator was not independent from industry and government. Sixty per cent of residents that were polled did not trust public authorities making decisions about energy projects and thought the regulator is not independent from government and industry.

- Trust, once lost, is hard to regain. In the minds of interview participants, the experience with the EUB in the ill-fated initial process could not be separated from the subsequent WATL project. Feelings of mistrust and disrespect lingered throughout the WATL process, despite efforts to address some problems that were initially encountered. Today, 71 per cent support or somewhat support the WATL line but 58 per cent don't think regulators are independent in their decisions.

- The case study identified a disconnect between regulators and rural Alberta. Most notably, landowners highlighted the regulator's lack of understanding of the rural farmer context (e.g., scheduling hearings during peak harvest season).

Wuskwatim hydroelectric facility – Nisichawayasihk Cree Nation, Manitoba

The Wuskwatim project initially was supposed to be a generating station and power dam on the Burntwood River in northern Manitoba. Over the course of consultations on the project, it was significantly redesigned as a low head dam (i.e., low fall of water) project with negligible flooding and a reduced generating capacity of 200 MW. The proponent was Manitoba Hydro, wholly owned by the Government of Manitoba. There was a joint regulatory process in this case, primarily in the hands of the Manitoba Clean Environment Commission (CEC) in cooperation with the federal Department of Fisheries and Oceans.

Wuskwatim was the first example in Canada of a utility company (Manitoba Hydro) and an Indigenous community (Nisichawayasihk Cree Nation [NCN]) entering into a partnership to develop a major generating station. The community was divided; while many community members valued the economic benefits and job opportunities, numerous issues were brought up during the hearings. These included environmental concerns about the project's impact on habitat, animals and water quality. A recurring theme was the legacy of mistrust based on adverse impacts from previous hydro projects, including increased flooding and a belief that Manitoba Hydro had broken promises. This sentiment was strong not only within NCN but also in other nearby Indigenous communities.

Key observations:

- Nisichawayasihk Cree Nation input during the design and planning phase of the project led to significant redesign. Input included combining the integration of traditional knowledge with scientific knowledge during the environmental assessment studies.

- Engagement did not stop with the construction of the project. For instance, traditional ceremonies were conducted before starting construction and continued throughout the six-year construction period. There was ongoing engagement with NCN about the monitoring and evaluation process.

- The proponents had to adapt to changes in regional power markets, which altered the projected profits and economic benefits for the community. This involved further consultations and changes to the project agreement. Changes included additional investment options and clarification of the jobs provision of the original agreement.

Gas-fired power facilities – Oakville and King Township, Ontario

This case study compared two natural gas electricity generation plant sites in the outskirts of the Greater Toronto Area. The proposed gas plants in the Town of Oakville (west of Toronto) and King Township (north of Toronto) were part of a province-wide initiative to upgrade and increase generation capacity in the wake of decisions to close coal-fired plants and lay-up a number of nuclear generation stations. Through 2006-2007, the Ontario Power Authority (OPA) engaged in a broad integrated power system planning process to determine the need for new facilities, including these two.

The power system planning process resulted in the siting of more than 30 electricity generation and transmission projects from 2006 until 2014. There were competitive procurement processes, in which various developers put together differing solutions (sites, facility design, locations) in response to a request for proposals. The province then determined the winning proposals through a point-based assessment process. Many (but not all) of the concerns discussed in this case study were ultimately addressed by a set of recommendations for planning and siting, by the OPA and the Independent Electricity System Operator (IESO) in 2013 and by the merger of both entities in 2015.

Oakville

In August 2008, the Ministry of Energy directed the OPA to competitively procure an 850 MW combined cycle gas generation facility in the region. Oakville residents organized resistance to the plant primarily after TransCanada Corporation won the competition. In March 2009, Oakville passed an interim control bylaw to suspend progress while also engaging in substantive opposition activities based on environmental concerns. The Ontario Municipal Board upheld Oakville's bylaw in December, and a variety of other regulatory processes were used by Oakville to slow or stop the process. In October 2010, the Ontario government cancelled the plant and engaged in negotiations and planning with TransCanada for an alternate location in Napanee, where the plant will be operational in 2018.

King Township

The need for the King Township generation facility was generally identified in 2005 as part of an Ontario Energy Board request to the OPA to address growing needs in the broad North York Region (and later as part of the broader Ontario Energy Plan). Throughout 2008, the OPA engaged in a competitive procurement process, ultimately deciding on the York Energy Centre in King Township. As Oakville had done, the municipality passed an interim control bylaw in January 2010. In July, however, the Ontario government passed Order in Council Regulation 305/10[7] which exempted the generation facility from the *Planning Act*[8] (specifically as concerned siting in the Greenbelt, an environmentally protected area) and also from local regulations (e.g., changes in local zoning or planning rules). Lawsuits and other administrative procedures were unsuccessful; the plant was built and began generating power in March 2012.

Key observations:

- Both cases were characterized by significant concerns with political interference and lack of regulatory independence. These actions occurred both during and after the procurement processes. Similar concerns were expressed about the cancellation of the Oakville plant, and regulations to exempt the King Plant from environmental regulations, or municipal laws. Over 65 per cent of residents expressed concerns for regulatory independence from government or industry.

- Many stakeholders complained that no comprehensive process existed to integrate concerns for safety, need, economics, environmental impacts, and community qualities. Many aspects of the siting process minimized certain kind of impacts, or did not allow them to be considered. These kinds of concerns were the basis for opposition for over 60 per cent of the residents who were opposed. Over 70 per cent of all respondents were concerned about local environmental impacts.

- The competitive procurement process created a dynamic in which potential participants were forced to pay attention to multiple possible sites and developers, making it quite difficult to devote appropriate resources to the siting process. Residents also complained that consultation did not occur, and that communication was one-sided. Over 50 per cent of residents were concerned about the lack of opportunity to influence the process, especially early on.

- Residents complained extensively about the difficulty of getting detailed information from the regulators and developers. Forty per cent of residents had concerns for the lack of information availability.

Wind farm – St-Valentin, Québec

The TransAlta St-Valentin project was selected by Hydro-Québec in 2008 from a call for tenders for wind power production in Québec (2005-2007). The project was to be situated in the southern part of the province, 50

7 *Energy Undertakings: Exempt Undertakings*, O Reg 305/10.
8 *Planning Act*, RSO 1990, c P.13.

kilometres from Montreal, providing a total capacity of 51.8 MW from 19 turbines of two MW and six turbines of 2.3 MW. A change of proponent during the project – known as a "flip" – undermined relations with stakeholders (flipping is frequent in the sector and involves the sale of the project to a new proponent after a procurement contract is secured but before the implementation phase).

St-Valentin, with 500 inhabitants, is the smallest of the 14 municipalities that comprise the Haut-Richelieu MRC (Municipalité régionale de comté). The main economic activity in the municipality and surrounding region is agriculture. The large areas of flat agricultural land are considered among the best in Québec. St-Valentin is situated along the Richelieu River, near the municipality of St-Paul-de-l'île-aux-Noix and close to Lake Champlain. It is a popular boat access point to the United States.

After a series of meetings starting in 2006 with landowners (those on whose lands the turbines would be installed), followed by the formal support of the municipality (and an official royalty agreement), and the awarding of a procurement contract by Hydro-Québec in 2008, the environmental impact assessment was undertaken in 2010. The Bureau d'audiences publiques sur l'environnement (BAPE) was responsible for the public hearings, the Environmental Department for the general process and the provincial government for the final decision.

Minimal consultation and potential for project modification led to opposition from St-Valentin's citizens and a coalition of the mayors of surrounding municipalities. The BAPE recommended the project be rejected and the provincial government did so in July 2011, based on the judgment that it fundamentally lacked the social acceptance necessary for sustainable development. The decision by the BAPE combined with lower demand for wind power, because other projects had been developed as part of the government's second call for projects, led to the project's cancellation.

Key observations:

- At the outset, the wind power sector was driven by purely political decisions aimed at the economic development of a specific region (Gaspésie), and by an important member of the Québec government. Both factors eroded the perceived legitimacy of the sector.

- The project was proposed during the development phase of the wind energy sector. The procedures and the rules were not clearly defined, especially at the regional/local level.

- The consultation and decision processes:

    - Were not adapted to the regional scope and impact of the project, i.e., they were not open enough to municipalities neighbouring St-Valentin. Furthermore, consultation and negotiation were too restrictive to allow for modification of the project from a citizen perspective.

    - The two-step process of a decision to award procurement tenders and then a final governmental authorization interacted with the "flip" to a new proponent and undermined the trust in both the proponent and public authorities.

- The opposition was well-organized, with regional, provincial and international expertise and experience. The BAPE public hearings created conditions favourable to the opponents.

- The estimated impact on the landscape made the project incompatible with the agricultural nature of the area and country living. The project was very close to the Richelieu River with its rich biodiversity. The presence of a number of prosperous local farmers and retired professionals at the hearings reinforced this effect.

Shale gas exploration in Kent County – Elsipogtog Nation, New Brunswick

As part of attempts to participate in the continental growth of the shale gas industry in 2010, the New Brunswick government awarded Texas-based SWN Energy Co. licences to explore 20 per cent of the province for shale gas potential, including large parts of Kent County in southeastern New Brunswick. This area, chosen for the case study, features a mix of coastal and inland villages, forested areas and the Elsipogtog Nation reserve community, which makes up approximately a tenth of the 30,800 residents in Kent County. The context of Kent County includes a history of expropriation, low literacy rates and a unique blend of Acadian, Anglo and

Elsipogtog Nation cultures. Persistent protests and blockades of exploration activity occurred throughout the summer of 2013 in Kent County, culminating in violent clashes in the fall of 2013. As part of the protest, Mi'gmaq people from across the Maritimes claimed treaty obligations to protect the area.

After exploration licences were issued in 2010, public protests in different exploration areas across New Brunswick, including Kent County, caught regulators (Departments of Energy and Mines, and of the Environment and Local Government) flat-footed. The province introduced a series of rules in 2011 and again in 2013 to address water contamination concerns, but public opposition remained high. A new provincial government elected in October 2014 carried out its promise to place a moratorium on hydraulic fracturing in December 2014. The new government appointed a commission to hold hearings across the province throughout 2015 to find out more about the root issues underlying public concern. The commission issued its report in early 2016 and in May 2016 the government extended the moratorium indefinitely.

Key observations:

- Interviews and survey questions revealed high levels of opposition to hydraulic fracturing for shale gas (70 per cent opposed or somewhat opposed) and that water contamination concerns were the most important issue for community members. Opposition levels reached 80 per cent for Indigenous residents.

- For some involved in the industry and in the business community, the fact that shale gas extraction, including hydraulic fracturing, had taken place in the southern Sussex region of the province without incident meant that risks were known and manageable and offered economic development benefits.

- Interviews and survey questions revealed a general lack of confidence in the ability of regulators to oversee a relatively new technology like hydraulic fracturing to extract shale gas. A majority (59 per cent) express low confidence in the capacity of regulator to enforce rules. Some also saw a problematic dual role played by the Department of Mines and Energy as both a proponent and regulator of the shale gas industry.

- Public trust in authorities was eroded as prominent public authority figures were forced to resign in scandal or were perceived to have been fired for criticism of shale gas development.

- Two-thirds of Kent County residents reported an increase in their level of confidence in public authorities responsible for shale gas regulation as a result of the moratorium decision.

- In the final analysis, publicly elected representatives decided the shale gas energy resources could not be developed in a way that would garner social acceptance.

Conclusions and recommendations

In this section, we bring together our observations and conclusions from both the interim report and from the case studies. We have endeavored to take it as far as possible toward propositions on which public authorities can act. We acknowledge that many fine sounding ideas are easy to say but much harder to execute. Ability to implement is affected by resource constraints, practical difficulties, the vicissitudes of politics and the modern communications environment.

Project proponents and public authorities alike need to be highly sensitive to the context in which the decision process is taking place. By the same token, the advice flowing from our work needs to be understood with both the larger societal context and the specific context of individual projects in individual jurisdictions. The latter, clearly, need to be taken into account case by case.

The decision-making context has changed from that which prevailed even up to early in this century. The natural tendency of communities to be distrustful of outsiders, combined with the newer contexts of low trust in government and a supercharged communications environment, have made traditional decision-making processes inadequate to the task in the future. The world of elite, centralized decision-making is a thing of the past.

We heard in the interim report interviews and saw in some case studies that decision-makers, including energy regulators, are grappling with this new reality. Much of it, however, is in the form of adjustments to the basic model rather than fundamentally rethinking the decision-making structure. Policy-makers talk of reformed processes but most have gotten little further than vague notions of social licence where everyone and every community is a decision-maker and where, inevitably, the predominant decision is no decision at all.

This is occurring in a context where new energy infrastructure is needed and where competitive pressures demand more, not less, efficient processes. The dominant controversies concern infrastructure to underpin our traditional energy economy. But the vast majority of future decisions will focus on new "clean" energy infrastructure to underpin a very low GHG economy. As the case studies show, clean energy may be as controversial as hydrocarbon energy at the local community level. Aspirations for a radical transformation of our energy systems by 2030 or even 2050 are at odds with the context in which energy decision-making will be taking place. Policy-makers who ignore this reality risk making the transformation even harder and more time consuming than market realities might suggest. Thus, we offer the following broadly framed recommendations.

1. *There is a need for a basic rethink of energy decision-making structures.*

The most basic question is: What is fair in terms of both outcome and process? Presumably, in a society where we count among our most basic values democratic accountability and the rule of law, fairness is to be found in systems that provide some guarantee of those values.

Fairness also warrants an ongoing capacity to engage citizens in the thought process about our collective energy future. Communities will insist that the public policy rationale for new projects be well-articulated and debated in the public domain. Public policy issues that warrant larger discussion include the future of Canada's single largest export industry (oil and gas); alternative pathways toward a low carbon future along dimensions of cost-effectiveness, efficiency, reliability and safety; the distribution of benefits; regional planning; and finding an appropriate balance between local concerns and the larger public interest in providing access to energy supplies.

2. *We need to rethink the structure and operations of energy regulatory bodies.*

The regulatory system is complex with many different sorts of bodies that interact with each other and with the broader policy system. Recent attempts by governments to develop seamless one-stop shopping, simplifying the system and making it more expeditious have, in many cases, been counterproductive. We need to rethink the basic idea of the independent regulator, restoring regulators to positions of legitimacy at the same time ensuring effective and productive relationships between regulators and policy makers. We need to develop new, flexible and credible means of engaging outside the formal processes, and innovative approaches, such as regulatory co-creation, to include civil society organizations and communities within formal processes.

3. *We need a fundamental rethink of the "role of local".*

Indigenous governments and local (municipal) governments are taking a growing role in thinking through their economic and energy futures but government decision-making processes were established long before this reality emerged. We need to think through the fundamental importance of community planning and the appropriate powers and roles of local authorities in project decision-making. Set against that is the question of when and under what circumstances it is the responsibility of a local community to defer to the interests of the broader society.

4. *We need a basic rethink of how information affects decision-making.*

Canada, for all its energy aspirations, is remarkably poor when it comes to energy information, particularly compared to the United States. More timely information communicated by credible parties may help to build trust and design viable decision processes.

None of this will come about easily or without cost. The sorts of decision processes implied in the above propositions will be more time consuming, they will constrain political choice and they will require administrative resources. They will entail potentially significant additional costs for projects to accommodate local concerns. They will require patience, particularly as Canadians contemplate the transformation of their energy systems to low carbon configurations. And they will still entail tough political choices when the wishes of local communities can't be reconciled with the interests of the broader society. ■

AN OVERVIEW OF VARIOUS PROVINCIAL CLIMATE CHANGE POLICIES ACROSS CANADA AND THEIR IMPACT ON RENEWABLE ENERGY GENERATION

*Dufferin Harper, Sharon Wong, Anne Drost, Tony Crossman, Doug Taylor, Nicole Bakker, Nardia Chernawsky, and Mathieu Nolin**

Canada is a signatory to the Paris Agreement, negotiated at the United Nations Conference of the Parties ("COP 21") in December of 2015. As part of its commitment, Canada confirmed that it will reduce its greenhouse gas ("GHG") emissions by 30 per cent below 2005 levels by 2030. On October 3, 2016, as part of the debate on a motion to support ratification of the Paris Agreement, the Prime Minister announced that Canada would implement a minimum price on carbon of $10/tonne throughout the country beginning in 2018. The price would increase by $10/tonne per annum to $50/tonne by 2022.

Although the Paris Agreement is a federal commitment, Canada will be relying on each of the provinces to enact appropriate climate change policies to achieve compliance. Indeed, during his carbon pricing announcement, the Prime Minister confirmed that Canada's carbon pricing policy would only apply in those provinces and territories that did not otherwise put a direct price on carbon or establish cap-and-trade system stringent enough to meet the federal target.

Because of the importance of provincial GHG regimes and policies, this article describes the various regimes applicable in each of the 'Big-Five' provinces of British Columbia, Alberta, Saskatchewan, Ontario and Quebec, which collectively account for over 90 per cent of Canada's GHG emissions.[1] This article also briefly describes the impact that the implementation of the various GHG regimes are having on each of the Big Five's energy supplies and the costs of electricity associated with the transition to renewable energy production.

BRITISH COLUMBIA

In 2008, the British Columbia ("B.C.") government took up the climate change challenge by setting specific GHG reduction targets and implementing the framework of a regime to achieve these goals. The government legislated that GHG emissions must be: at least 33 per cent less than 2007 levels by 2020; and 80 per cent less than 2007 levels by 2050.[2]

To help achieve these goals, the government created a number of legislative and policy measures including a carbon tax and the first stages of a cap and trade framework. Since 2012, the carbon tax has been set at

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1 According to: Environment and Climate Change Canada, *National Inventory Report 1990-2014: Greenhouse Gas Sources and Sinks in Canada, Canada's submission to the UNFCCC* (Gatineau: 11 April 2016), in 2014 provincial emissions were approximately as follows: Alberta – 37 per cent; Ontario – 23 per cent; Quebec – 11 per cent; Saskatchewan – 10 per cent; and British Columbia – 9 per cent.

2 *Greenhouse Gas Reduction Targets Act*, SBC 2007, c 42.

\$30 per tonne of carbon dioxide equivalent emissions ("CO_{2e}").[3] This results in a tax that differs depending on the type of fuel and the anticipated carbon emissions (e.g., \$5.70 per cubic metre of natural gas or \$62.31 per tonne of high heat value coal).[4] The tax is applied to most carbon-based fuels including gasoline, diesel, natural gas, heating fuel, propane, and coal, as well as certain combustibles including peat and tires when used to produce heat or energy. The B.C. government also introduced the first stages of a cap and trade framework, which included the requirement to report GHG emissions, although it did not implement any cap on emissions or legislate the trading of emission credits.[5]

Since January of 2016, there have been three significant developments in the GHG regulatory regime in B.C. First, the *Greenhouse Gas Industrial Reporting and Control Act* ("*GHG Act*")[6] came into force, which marked a significant shift in the province's approach to GHG emissions. Second, the B.C. government released the Climate Leadership Plan ("2016 BC Plan"),[7] which sets out the government's current vision and action plan for attaining the legislated reduction targets. Third, the federal government approved the Pacific NorthWest LNG project ("PNW") located near Prince Rupert B.C. The federal government's approval included, for the first time, a maximum cap on annual project-specific GHG emissions.

GHG Act

On January 1, 2016, the *GHG Act* and its associated regulations came into force, which signaled a shift away from the previously proposed cap and trade system and aligned B.C. with the emissions intensity[8] approach taken by Alberta.

The *GHG Act* creates intensity-based GHG emission performance standards for prescribed industrial facilities and sectors. Performance standards are currently in place for liquefied natural gas ("LNG") facilities. The emissions intensity benchmark for LNG facilities is 0.16 tonnes of CO_{2e} per tonne of LNG produced. The benchmark for coal-based electricity generation operations, while not yet in force, will be zero tonnes of CO_{2e}, which effectively prohibits these operations in B.C.

Under the new GHG reporting framework, industrial operations must continue to report and, where applicable, verify GHG emissions as they have since 2010. Specifically, industrial operations located in B.C. and emitting 10,000 tonnes of CO_{2e} or more per year must report their GHG emissions. Industrial operations emitting 25,000 tonnes or more of CO_{2e} per year must have their emissions reports verified by an accredited third party.

The *GHG Act* also broadens available alternative compliance mechanisms. If an entity cannot meet the prescribed emissions target for its facility or sector, it may apply compliance units to avoid penalties. Compliance units include offsets funded units or earned credits, which can be used or traded. Offset units, are issued by the provincial government and will be based on accepted and verified offset projects. Funded units are essentially payment of a prescribed amount per tonne of GHG into a prescribed account. Earned credits can be earned if emissions in a reporting period are less than the emissions target.

2016 BC Plan

In 2008, the provincial government published its Climate Action Plan[9] ("2008 BC Plan"). In May 2015, the B.C. government appointed a Climate Leadership Team Panel ("Panel") to update the 2008 BC Plan and provide recommendations to achieve the legislated GHG emissions reductions targets, while also taking into account economic growth, B.C.'s Liquefied Natural Gas Strategy, and

3 *Carbon Tax Act*, SBC 2008, c 40.
4 Ministry of Finance, *Tax Rates on Fuels: Motor Fuel Tax Act and Carbon Tax Act*, Tax Bulletin MFT-CT 005 (Revised August 2016).
5 *Greenhouse Gas Industrial Reporting and Control Act*, SBC 2014, c 29.
6 *Ibid.*
7 British Columbia, *British Columbia's Climate Leadership Plan* (Victoria: August 2016), online: <http://climate.gov.bc.ca>.
8 Emissions intensity refers to the quantity of CO_{2e} released by a facility per unit of production. As a facility becomes more carbon efficient it can produce the same unit of production with less CO_{2e} released.
9 British Columbia, *Climate Action Plan* (Victoria: 2008), online: <http://www.gov.bc.ca/premier/attachments/climate_action_plan.pdf>.

B.C.'s Jobs Plan. The Panel's final report was issued in November 2015 and contained 32 recommendations.[10] Recommendations of note included:

- Increasing the rate of the existing carbon tax by $10/year per tonne, commencing in July 2018. Note: There were no recommendations for when the increases should end or how high the tax rate should ultimately go.

- Lowering the provincial sales tax from 7 to 6 per cent, to provide relief for consumers for increased costs arising from the program, in particular, the rising rates of the carbon tax.

- Expanding the scope of the carbon tax to apply to all GHG emission sources, including non-combustion sources (e.g. fugitive emissions from pipelines and process emissions from industrial plants).

- Implementing targeted measures to protect emissions-intensive, trade-exposed sectors.

- Establishing sector-specific GHG reduction goals for the transportation, industrial and built environment sectors.

In August 2016, the B.C. government released the 2016 BC Plan.[11] The 2016 BC Plan updates the 2008 BC Plan and responds, in part, to the Panel's recommendations for climate action in B.C. The 2016 BC Plan attempts to balance the actions required to reduce GHG emissions to reach 2050 targets with the government's policies aimed at protecting the economy.

What the 2016 BC Plan Includes

The 2016 BC Plan outlines more than 20 climate action areas that will be developed by the Province. Specifically, the 2016 BC Plan identifies action items to reduce GHG emissions under six categories: natural gas; transportation; forestry and agriculture; industry and utilities; communities and the built environment; and the public sector. Some of the action items relevant to the energy industry include:

Natural Gas Action Items

- Launching a strategy, including a new Clean Infrastructure Royalty Credit Program, to reduce upstream methane emissions by 45 per cent through the reduction of fugitive and vented emissions

- Developing regulations to enable carbon capture and storage ("CCS") to proceed in B.C.

- Investing in infrastructure to power natural gas projects in Northeast B.C. with clean electricity

Transportation Action Items

- Increasing the Low Carbon Fuel Standard from 10 per cent by 2020 to 15 per cent by 2030 to reduce the carbon intensity of transportation fuels

- Increasing the pool of incentives available to encourage commercial fleets to switch to natural gas

- Expanding the regulatory framework to support the installation of charging stations for zero emission vehicles

- Expanding the Clean Energy Vehicle Program to encourage the use of zero emissions vehicles through new vehicle incentives and infrastructure, education, and economic development initiatives

- Industry and Utilities Action Items

- Ensuring that 100 per cent of the electricity supply acquired by BC Hydro for the integrated grid be from renewable or clean sources, except where there are concerns regarding reliability or costs

- Regulatory amendments to allow utilities to provide additional incentives to help fuel marine, mining, and remote industrial power generation sectors

10 British Columbia, *Climate Leadership Team: Recommendations to Government* (Victoria: 31 October 2015), online: <http://engage.gov.bc.ca/climateleadership/files/2015/11/CLT-recommendations-to-government_Final.pdf>

11 2016 BC Plan, *supra* note 7.

- Regulatory amendments to set energy efficiency requirements for new and replacement gas-fired boilers, as well as to enable further incentives to encourage the adoption of technologies that reduce emissions from gas-fired equipment

Communities and the Built Environment Action Items

- Regulatory amendments to increase efficiency requirements for gas fireplaces, air source heat pumps, and natural gas space and water heating equipment

- Implementing a number of policies to encourage the development of Net-Zero Energy buildings, including accelerating and enhancing increased energy efficiency requirements in the B.C. Building Code

With these initiatives, the government believes that it can meet its legislated target of reducing emissions by 80 per cent below 2007 levels by 2050. Of course, until the government passes laws to implement the various action items, the 2016 BC Plan will be only that — a plan, and will have no legal effect.

What the 2016 BC Plan Excludes

While the 2016 BC Plan includes a number of the Panel's recommendations, it did not address some of the Panel's more significant and controversial recommendations. As such, what is most noteworthy is not what is in the 2016 BC Plan, but what is omitted. Panel recommendations that were not addressed in the 2016 BC Plan include:

1) *Increase in Carbon Tax* - The carbon tax rate has been at $30/tonne since 2012. The Panel recommended an increase in the carbon tax rate by $10/year commencing in 2018 and expanding the scope of the tax to include all emissions (i.e. including fugitive and process emissions from natural gas, coal mining, and cement and metal production). The government responded to the Panel's recommendation by stating that now is not the time to consider increasing the carbon tax when other provinces and the federal government are implementing carbon pricing policies and "catching up" to B.C.'s lead.

2) *Interim GHG Emission Targets* - The Panel recommended that the government set an interim 2030 GHG target. The Panel also recommended sectoral emission reduction targets. These recommendations were not addressed in the 2016 BC Plan.

3) *Environmental Assessment* - The Panel recommended amending the provincial *Environmental Assessment Act*[12] to include the social cost of carbon in the environmental assessment process. This was also not included in the 2016 BC Plan.

The government has promised to update the 2016 BC Plan over the next year in response to work underway between the federal government and the provinces in regard to a national approach to climate action. The 2016 BC Plan is therefore only a "first step" and recommendations from the Panel's report may ultimately find their way into an updated plan.

PNW

On September 27, 2016, the federal government approved the PNW subject to over 190 legally binding conditions. At full production, PNW will receive approximately 9.1 x 10^7 cubic metres per day of pipeline grade natural gas and produce up to 20.5 million tonnes per annum of LNG for over 30 years.[13]

The federal government's approval of PNW includes a maximum cap on annual project GHG emissions. Specifically:

- At the commissioning of Train 2, PNW must have an annual average emissions intensity of less than or equal to 0.22 tonnes of CO_{2e} per tonne of LNG produced and shall emit no more than a total of 3.2 million tonnes of CO_{2e} per calendar year.

- At the commissioning of Train 3, PNW

12 *Environmental Assessment Act,* SBC 2002, c 43.
13 Canadian Environmental Assessment Agency, *Environmental Assessment Decision Statement* (Ottawa: CEAA, 27 September 2016) at 1, online: CEAA <http://www.ceaa.gc.ca/050/documents-eng.cfm?evaluation=80032>.

> must have an annual average emissions intensity of less than or equal to 0.21 tonnes of CO_{2e} per tonne of LNG produced and shall emit no more than a total of 4.3 million tonnes of CO_{2e} per calendar year.

PNW must also implement mitigation measures during all phases of the project to reduce and control air emissions and GHG emissions.

Industry Implications

These recent GHG-related developments have a number of implications for B.C. industry, particularly the energy industry.

First, commentators have noted that the carbon tax has been effective at reducing GHG emissions in B.C. However, the tax has also had a significant adverse impact on industries that are energy-intensive and trade-exposed, such as the cement industry.[14]

Second, there has been a greater emphasis on clean, renewable energy throughout the province. However, given that 98 per cent of B.C.'s power generation portfolio currently comes from clean or renewable resources, including hydro,[15] this has not resulted in a significant change in renewable energy development or in energy prices. The B.C. government has also been careful to ensure that this shift towards renewable energy does not discourage the development of LNG projects in the province. For example, the government amended its initial objective of generating at least 93 per cent of electricity from clean or renewable resources to exclude electricity necessary to service demand from LNG facilities that will liquefy natural gas for export by ship.[16]

Third, in the future, proponents of large industrial facilities, including LNG facilities, should anticipate caps on their GHG emissions as the provincial and federal governments attempt to meet their respective GHG emission reduction goals. This will likely ensure the continued emphasis on, and use of, renewables in B.C. for years to come.

ALBERTA

Alberta's GHG regulatory regime has been in place since July of 2007, which makes it the oldest GHG regulatory regime in North America. The regime is set out in the *Climate Change and Emissions Management Act*[17] and regulations thereunder, the most notable being the *Specified Gas Emitters Regulation* ("*SGER*").[18] It is an emissions intensity regime and is predicated upon a facility becoming more carbon efficient over time. Pursuant to the *SGER*, any facility that emits greater than 100,000 tonnes of CO_{2e}/annum ("large emitter") is required to reduce its emissions intensity as compared to its baseline intensity[19] by 15 per cent. The emissions intensity reduction as compared to a facility's baseline will increase to 20 per cent on January 1, 2017.

Regulatory Compliance

A large emitter can comply with the emissions intensity reduction requirements under the *SGER* in the following four ways:

1) Meeting the emissions intensity reduction requirements by increasing its efficiency of production as compared to its baseline through operational and process changes;

2) Purchasing emissions performance credits ("performance credits");

3) Purchasing emissions offset credits ("offsets") from facilities that are not large emitters; or

4) Contributing to the climate change and emissions management fund ("Fund").

Performance credits arise in circumstances

14 Cement Association of Canada, Press Release, "Cement Industry Welcomes B.C. Government Action on Carbon Tax" (27 February 2015), online: CAC <http://www.cement.ca/en/News-Releases/Cement-Industry-Welcomes-B-C-Government-Action-on-Carbon-Tax.html>.
15 2016 BC Plan, *supra* note 7 at 28.
16 *British Columbia's Energy Objectives Regulation*, BC Reg 234/2012.
17 *Climate Change and Emissions Management Act*, SA 2003, c C-16.7.
18 *Specified Gas Emitters Regulation,* Alta Reg 139/2007.
19 Baseline intensity refers to the quantity of CO_{2e} released per unit of production during the first few years of a facility's start-up, or if it the facility has been established for quite some time, during the 2003-2005 time-frame.

where a large emitter exceeds its required emissions intensity reduction requirements through operational efficiencies. The excess reductions or performance credits can then be sold to other large emitters that cannot otherwise meet their respective compliance obligations.

Offsets are generated by Alberta facilities that are not large emitters and not otherwise required to reduce emissions by operation of law. The offsets must be real, demonstrable and quantifiable as described in an accepted offset protocol, and can include CCS. Offsets arise when an activity or process is undertaken that generates less CO_{2e} than the average or accepted norm for that activity or process. A simple example is electricity generated from a wind-turbine. Alberta has a calculated average of CO_{2e} emissions per unit of electricity. Wind-turbines generate electricity in a manner that emits less CO_{2e} than the average. The difference, or delta, can be sold as offsets. Indeed the ability to sell both the electricity generated from a wind-project as well as the offsets generated from the same project may be the only reason that certain wind-projects are financially viable. Alberta currently has 34 approved offset protocols covering activities and processes as disparate as aerobic composting to electrical production to bio fuels to energy efficiency in commercial buildings.

The Fund monies are segregated from other government monies and used for projects that reduce GHG emissions and adapt to climate change. Between July of 2007 and 2015 the costs of contributing to the Fund was set at \$15/tonne of CO_{2e}. In January of 2016 the Fund costs increased to \$20/tonne and are set to increase to \$30/tonne in January of 2017. Since July of 2007, approximately \$740 million has been contributed to the Fund by large emitters. Because a large emitter can contribute to the Fund as a means of meeting all of its compliance requirements, the price of the Fund essentially dictates the maximum value a large emitter will pay for a performance credit or an offset. The recent increase in the Fund price from \$15 to \$20 in 2016 and the further increase to \$30 set for 2017 has positively and significantly impacted the value of renewable energy offsets, which in turn have had a positive impact on the financial viability of renewable energy projects.

Criticisms of the existing *SGER* regime have included the following:

- The regime is too Alberta-centric, particularly with respect to the requirement that offsets must be Alberta-based.
- The Fund price is too low, although with the recent increase to \$20/tonne and the future increase to \$30/tonne, presumably this criticism will wane.
- The lack of any restriction on Fund contributions. In other words there is no requirement for a facility to undertake any efficiency upgrades. Rather a facility can continue to meet its efficiency obligations solely by contributing to the Fund.
- No absolute cap on emissions.
- The regime is too restricted in scope and does not target all contributors, particularly consumers.

Climate Leadership Plan

In the fall of 2015 Alberta released its Climate Leadership Plan ("AB Plan"). Once fully implemented, it will significantly change numerous aspects of Alberta's existing climate change regime. Highlights include:

- Early phase-out of coal-fired power plants, which are amongst the most significant GHG emitters
- Replacement of the emissions intensity regime with product-based emissions performance standards
- Expansion of the program of only targeting large emitters, to a wide array of small and large emitters as well as consumers through the implementation of a broad-based carbon levy
- Capping oil sands emissions at 100 megatonnes
- Targeting methane emissions in the oil and gas sector
- Renewed focus on energy-efficient initiatives

Alberta currently obtains approximately 51 per cent of its electrical generation from coal-fired power plants. Pursuant to the AB Plan, GHG emissions from these plants will be completely phased out by 2030, with approximately 2/3 of the electrical generation to be replaced by renewable energy. This is a significant change. Not only will it dramatically change the electricity supply mode within Alberta, it will necessitate significant electrical transmission changes as the Province struggles with the siting of renewable energy projects in areas that may or may not be close to existing transmission infrastructure.

Another component of the AB Plan involves the replacement of the current emissions intensity program with product-based emissions performance standards. Under an emissions performance standard, facilities will be compared to a product-specific emissions standard, rather than an historic facility-specific standard. Facilities that cannot meet the emissions performance standard will be subject to a carbon levy. As of January 1, 2017, the levy will be \$20/tonne of CO_{2e}. That amount will increase to \$30/tonne as of January 1, 2018. The anticipated effect on businesses is that it will drive best-in-class performance. As for consumers, the \$30/tonne levy is expected to translate into additional fuel costs of approximately \$1.5/gigajoule of natural gas, 6.7 cents/litre of gasoline, 8.0 cents/litre of diesel and 4.6 cents/litre of propane. In an approach similar to that of B.C., the Alberta government has elected not to increase the carbon levy above \$30/tonne until the economy becomes stronger and the actions of other jurisdictions, including the federal government, are better known.

A further key component of the AB Plan is its broad application. The existing regime only applies to large emitters, which account for approximately 45 per cent of provincial GHG emissions. Once fully implemented, the Plan is expected to cover approximately 78-90 per cent of provincial GHG emissions, including large emitters, small emitters and consumers.

In what appears to be a direct response to criticisms that Alberta hasn't done enough to restrict GHG emissions in the oil sands sector, the AB Plan contemplates an absolute annual emissions cap of 100 megatonnes of GHG from oil sands production. Currently, oil sands emissions account for approximately 70 megatonnes of GHGs per annum. By transitioning to performance-based standards, coupled with the implementation of a legislated emissions cap, it is expected to create the conditions for continued oil sands growth in a manner that rewards innovation and enables oil sands producers to remain globally competitive. As stated by Alberta's Premier Notley when she outlined the AB Plan:

> The simple fact is this: Alberta can't let its emissions grow without limit. But we can grow our economy by applying technology to reduce our carbon output per barrel. And that is what this limit will provide.

The AB Plan will also include provisions for recognition of new upgrading and co-generation in the oil sands sector. Alberta's existing regime has been criticized for not directly addressing the benefits of co-generation (coupling energy production with heat production).

The AB Plan specifically targets methane emissions, particularly in the oil and gas sector. Under the AB Plan, methane emissions from oil and gas operations are anticipated to decrease by 45 per cent. The reduction will occur through the application of emissions design standards on all new facilities coupled with the development of a joint methane reduction initiative, which will include industry, environmental groups and indigenous communities.

The final aspect of the AB Plan involves a renewed focus on energy efficiency. Details of the program are anticipated to be released in 2017.

Notwithstanding the AB Plan's multi-faceted approach to GHG regulation, it is interesting to note that it does not encompass any interprovincial or international cap-and-trade measures. This means that Alberta will remain isolated from any of the cap-and-trade regimes that other provinces, such as Ontario and Quebec, have signed onto. The AB Plan represents a made-in-Alberta approach in response to an Alberta problem. Whether or not remaining isolated from other jurisdictions will be beneficial to Alberta in the long term is unclear.

Transitioning to a Renewable Electricity Program

In March of 2016, as a result of the AB Plan, the Alberta government tasked the Alberta Electric System Operator ("AESO"), the independent system operator for Alberta's electricity system, with developing and implementing a renewable electricity program ("REP") that would increase the province's renewable energy generation capacity as a percentage of total generation capacity from 11 per cent to 30 per cent by 2030.

The AESO provided its recommendations regarding the REP to the province at the end of May, 2016. Although the recommendations regarding the REP are not yet public, the AESO has provided some indications as to what those recommendations entail. More particularly, it is expected that:

i) The REP will involve a fuel neutral competitive auction process with the first auction competitions for renewable energy projects to be held in late 2016 with anticipated project in-service dates of 2019. The fuel-neutral concept is predicated upon the concept that no particular renewable electricity method is preferred over another;

ii) The REP will fit within Alberta's existing deregulated competitive electricity market. In that regard it is unlikely that Alberta will adopt a feed-in tariff ("FIT") program that has been implemented in other jurisdictions, notably Ontario; and

iii) AESO's recommendations will generally follow those set out in the Alberta Climate Leadership Panel report ("Report"),[20] which was released just prior to the Plan, and upon which the Plan is based. One of the critical aspects of the Report is the proposed purchase of a project's renewable energy certificates ("RECs") by the government. In essence, as a means of supporting renewable energy projects, the government will purchase a project's RECs pursuant to long-term contracts.

Despite the specifics of the REP remaining unclear, beginning in late 2016 it appears that renewable energy producers will have an additional choice of markets for their environmental attributes. They will still be able to sell them as offsets. As an alternative, if successful at the 2016 auction competition (or any subsequent auctions), they will be able to sell them under long-term purchase contracts to the government of Alberta ("Government-Purchased RECs"). In order to limit the government's exposure to high costs of support, the Report recommends a ceiling price for the Government-Purchased RECs of, at most, $35 per megawatt hour ("MWh") which is roughly equivalent to $90/tonne CO_{2e} premium over natural gas generation under Alberta's current system.

While the REP will obviously lead to increased renewable energy generation, its effect on electricity prices remains unclear. The average electricity pool price in Alberta decreased by 33 per cent from 2014 to 2015. The effect on electricity prices of transitioning from a jurisdiction where over 50 per cent of its electrical generation comes from baseload coal production to one that is much more highly dependent on renewable energy production, with no guaranteed electrical energy production levels, is unknown. Further, the costs of resolving the infrastructure challenges and the financial implication surrounding the lack of guaranteed energy supply that are associated with renewable energy production are also unknown.

SASKATCHEWAN

With just over 3 per cent of Canada's population, emissions from Saskatchewan account for over 10 per cent of Canada's total, making it the largest provincial emitter on a per capita basis.[21]

Despite the significant impact of Saskatchewan emissions on a national level, the province currently neither regulates emissions nor imposes any legislated emissions reductions targets. While the Saskatchewan Premier has

20 See Government of Alberta, *Climate Leadership Report to Minister* (Edmonton: 20 November 2015), online: <http://www.alberta.ca/documents/climate/climate-leadership-report-to-minister.pdf>.

21 Paul Boothe & Félix-A. Boudreault, *By the numbers: Canada's GHG Emissions* (London: Lawrence National Centre for Policy and Management: Ivey Business School at Western University, 2016).

admitted that the province needs to do better in terms of its record on climate change, he has consistently taken the position that climate change policies must be designed with the economy in mind.[22]

With a view to limiting the impacts on its emissions-intensive economy, Saskatchewan's climate change policies have primarily focused on technological developments, specifically CCS and support for the development of renewable energy sources.

Emissions management legislation: On hold since 2010

By 2010, Saskatchewan had made significant progress towards the development of a provincial climate change strategy, and had even passed legislation regulating GHG emissions. Pursuant to the *Management and Reduction of Greenhouse Gases and Adaptation to Climate Change Act* ("*Sask CC Act*"),[23] "regulated emitters" would be required to reduce their annual GHG emissions by a prescribed amount relative to a baseline in order to collectively meet the provincial emissions reduction target. At the time the legislation was passed, Saskatchewan had adopted a GHG emissions reduction target of 20 per cent below 2006 levels by 2020.[24]

"Regulated emitters," were facilities that emit 50,000 tonnes or more of CO_{2e} annually. Failure to comply with reductions would result in the requirement to make a carbon compliance payment (anticipated at the time to be set at \$15 per tonne of CO_{2e}). The *Sask CC Act* also contemplated the development of alternative compliance mechanisms for regulated emitters including certified investments in a technology fund, recognition for early action, credits for emission intensive or trade-exposed industries, and the ability to purchase carbon offsets.

The *Sask CC Act* was passed and received royal assent in 2010. However, it has yet to be proclaimed, and there is no indication that the Government of Saskatchewan intends to bring this legislation into force in the near future. With the exception of a legislated minimum 7.5 per cent ethanol content in gasoline (prescribed by the *Ethanol Fuel Act*)[25] and regulatory requirements for the reduction of flaring and venting associated gas during upstream oil and gas operations (pursuant to *Directive S-10*: *The Saskatchewan Upstream Petroleum Industry Associated Gas Conservation Standards*),[26] Saskatchewan's action on climate change has largely been limited to policy rather than legislative action.

CCS

Approximately 46 per cent of Saskatchewan's electricity comes from coal-fired generation.[27] Unlike provinces such as Alberta and Ontario, Saskatchewan does not have plans to phase out its use of coal. It has, instead, focused on the development of CCS technology, and the use of that technology to retrofit coal-fired generation facilities in the province.

On October 2, 2014, the Boundary Dam Integrated CCS Project ("ICCS Project"), located at the Boundary Dam Power Station near Evanston, Saskatchewan, became operational. The ICCS Project was initiated in 2008 in response to proposed federal regulations that required coal-fired generation units that are new, or that have reached the end of their useful life, to emit no more than 420 tonnes of CO_{2e} per gigawatt hour.[28] The \$1.47 billion[29] government-industry partnership between the Government of Canada, Government of Saskatchewan, SaskPower, and private industry involved the retrofitting of Unit #3 at the coal-fired Boundary Dam Power Station with a system for capturing CO_2, SO_2 and nitrous

22 Aaron Wherry, "Amid a climate-change parade, Brad Wall casts himself as Harper Lite", *Maclean's* (23 November 2015): "…we need to do better in terms of our record on climate change, our province needs to do better, and I can talk a little bit about that, but we can't forget the economy".

23 Bill 126, *An Act respecting the Management and Reduction of Greenhouse Gases and Adaptation to ClimateChange,* 3rd Sess, 26th Leg, Saskatchewan, 2010 (assented to 20 May 2010).

24 Government of Saskatchewan, News Release, "Saskatchewan takes real action to reduce greenhouse gas emissions" (11 May 2009).

25 *The Ethanol Fuel Act*, SS 2002, c E-11.1.

26 Government of Saskatchewan, *Directive S-10: The Saskatchewan Upstream Petroleum Industry Associated Gas Conservation Directive*, (Regina: November 2015).

27 SaskPower, "Our Supply Mix", online: < http://www.saskpower.com/wp-content/uploads/power_sources_Apr2016.jpg>.

28 *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*, SOR/2012-167, s 3.

29 SaskPower, News Release, "CCS performance data exceeding expectations at world-first Boundary Dam Power Station Unit #3" (11 February 2015).

oxides. The captured CO_2 is sold to Cenovus Energy, who uses it for enhanced oil recovery operations. The ICCS Project is acknowledged as the world's first full-scale coal CCS project, and represents a significant achievement for Saskatchewan.

SaskPower, Saskatchewan's provincially-owned utility that operates the ICCS Project, has reported that the project produces 110-megawatts ("MW") of power while eliminating SO_2 emissions, reducing CO_2 emissions by 90 per cent, and capturing up to 1 million tonnes of CO_2 annually. However, the ICCS Project has been the subject of significant criticism. Downtime required for maintenance has limited operations of the project to 40 per cent of its capacity, which has in turn prevented SaskPower from producing its contracted volume of CO_2 for sale to Cenovus Energy, which purchases the CO_2 at a cost of $25 per tonne. In addition to lost sales, SaskPower has been required to pay approximately $12 million in penalties to Cenovus Energy. This has contributed, at least in part, to SaskPower requests for multiple consumer electricity rate increases since 2014.[30] In order to mitigate additional losses, SaskPower renegotiated its CO_2 supply contract with Cenovus Energy in June 2016.[31]

Notwithstanding these challenges, the provincial government remains optimistic about CCS technology. SaskPower opened a CCS test facility at the Shand Power Station in June 2015, which provided CCS technology developers with an opportunity to test their processes at a commercial power plant. In order to avoid having to close Units 4 and 5 of the Boundary Dam Power Station pursuant to federal regulations, the Saskatchewan government is considering whether to retrofit those aging units with CCS, and expects to make a decision in this regard before the end of 2017. Further, in June 2016, the Premiers of Saskatchewan and Quebec signed a memorandum of understanding pursuant to which their respective provincial governments agreed to accelerate the development and deployment of CCS technologies, exchange updates and information on CCS projects and technologies, and work together to explore further collaborations in relation to CCS.

SaskPower has stated that, with learning-by-doing from the ICCS Project, it could likely achieve $200 million in cost savings on a similar plant. However, it has been estimated that the ICCS Project will generate a loss of approximately $1 billion over its lifespan, which could cost Saskatchewan ratepayers up to $750 million over 30 years.[32] Alternatively, if investments are not made to significantly reduce emissions, it will be necessary to retire the majority of coal-fired generation in the province pursuant to federal regulatory requirements.[33] Units 4 and 5 of the Boundary Dam Power Station, which account for 278-MW of generation, will reach the end of their 50-year useful life at the end of 2019, and an additional 886-MW of coal-fired generation must be retired by 2029 if investments in CCS are not made.[34]

SaskPower's 50 per cent Renewable Energy Target

In November of 2015, SaskPower announced its commitment to achieving 50 per cent renewable energy capacity by 2030. This will involve doubling Saskatchewan's renewable energy capacity in 15 years.

Approximately 25 per cent of Saskatchewan's generation capacity currently comes from renewable sources: 20 per cent from hydro and 5 per cent from wind. The Minister responsible for SaskPower has stated that doubling renewable energy capacity will involve "a major expansion of wind power augmented by other renewables such as solar, biomass, geothermal and hydro, to go along with the world leading

30 In May 2016, SaskPower applied for two rate increases: A 5 per cent increase to take effect July 1, 2016 and a further 5 per cent increase to take effect January 1, 2017. Rate increases were also approved in 2014 and 2015. Various critics have pointed to the significant costs associated with the Boundary Dam Integrated CCS Project as the cause of higher rates: Will Chabun, "SaskPower seeks 10.25-per-cent rate hike over next eight months", *Regina Leader-Post* (20 May 2016); Stefani Langenegger, "Sask. carbon capture plant doubles the price of power", *CBC News* (17 June 2016).

31 DC Fraser, "SaskPower renegotiated contract to avoid $91.8M penalty", *Regina Leader-Post* (13 June 2016).

32 Office of the Parliamentary Budget Officer, *Canada's Greenhouse Gas Emissions: Developments, Prospects and Reductions* (Ottawa: PBO, 21 April 2016) at 41.

33 *Supra* note 28.

34 SaskPower, *Rate Application (2016 and 2017)* at 10, online: SRR <http://www.saskratereview.ca/docs/saskpower2016/2016-and-2017-rate-application.pdf>.

Boundary Dam 3 carbon capture project and more natural gas generation."[35]

To the extent that the above statement represents the Saskatchewan government's definition of "renewable," it is notable that it differs from the Natural Resources Canada definition, which has been adopted by Alberta for the purposes of its REP. The Natural Resources Canada definition of "renewable" does not include natural gas or nuclear energy, includes only limited forms of biomass, and does not reference CCS.

In order to achieve its 50 per cent renewable target, SaskPower is generally reviewing the potential for new hydro projects, hydro power imports from other provinces, biomass, and geothermal power projects in the province. SaskPower specifically plans to develop at least 60-MW of ground-mount solar photovoltaic generation. The 60-MW is expected to consist of two 10-MW projects procured from the private sector,[36] two 10-MW projects developed by a SaskPower-First Nations Power Authority partnership, with community driven projects accounting for the final 20-MW. The provincially-owned utility is relying most heavily on an increase in wind power capacity to achieve its 50 per cent renewable target. Specifically, SaskPower has stated that it intends to achieve 30 per cent wind power capacity by 2030 ("Wind Capacity Target").

The addition of new wind power capacity is already underway in the province. Three private sector projects are currently in development, representing 207-MW of new generation capacity. SaskPower has also committed to adding three 100-MW projects to the provincial grid by 2024. A competitive procurement process for the first of these 100-MW projects is anticipated to begin before the end of 2016.[37] The development of these projects will bring Saskatchewan's total wind power capacity to approximately 730-MW, or 15 per cent of the province's total generation capacity. Plans regarding how to further increase this total to achieve the 30 per cent target have yet to be finalized.

Interestingly, in comparison to the fuel-neutral approach taken by Alberta's REP, the Saskatchewan renewables procurement program has followed the path of the Ontario Large Renewables Program by specifying a particular quantity of both solar and wind generation capacity that it intends to introduce to the grid.

On September 13, 2016, Saskatchewan had a significant setback in meeting its Wind Capacity Target when the approval of the largest of the three wind power projects currently in development was refused by the Minister of Environment.[38] The Chaplin Wind Energy Project is a 177-MW wind power project proposed by Windlectric Inc., a subsidiary of Algonquin Power. It was the first wind power project to undergo a provincial environmental assessment and was proximate to two internationally recognized important bird areas.[39] While Windlectric Inc. had proposed a number of mitigation measures to address bird mortality risks and potential impacts to migratory bird corridors (i.e. avoiding linear arrangement of turbines, feathering blades, and increasing cut-in speeds), the Environment Minister noted that these mitigations for individual components of the project could not satisfactorily address the fact that the project had been sited within a migratory bird corridor and in proximity to bird congregation areas.

The Government of Saskatchewan publically announced its refusal to approve the Chaplin Wind Energy Project on September 19, 2016, the same date on which it released guidelines for the siting of future wind energy projects in the province.[40] The *Wildlife Siting Guidelines for Saskatchewan Wind Energy Projects* prescribe a 5-kilometre buffer zone around environmentally sensitive areas such as national and provincial parks, ecological reserves,

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35 SaskPower, News Release, "SaskPower to develop wind, solar and geothermal power to meet up to 50% renewable target" (23 November 2015).

36 For the first 10-MW project, the Request for Qualification process is anticipated to commence before the end of September 2016 with the Request for Proposals process taking place by the end of December 2016.

37 Requests for Qualification will be issued in November 2016, followed by Requests for Proposals in Q1 2017.

38 *Chaplin Wind-Energy Project* (13 September 2016), EAB 2013-013, online: < http://publications.gov.sk.ca/documents/66/94179Chaplin%20Wind%20Energy%20Project%20MD%20&%20RfD%20(PubCentre).pdf>.

39 Specifically, Chaplin Lake, which is part of a system designated as a Western Hemisphere Shorebird Reserve Network, is located 4.5 km south of the nearest proposed wind turbine and Paysen, Williams and Kettlehut lakes, which are designated as Important Bird Areas, are located approximately 6 km north of the nearest proposed wind turbine.

40 Government of Saskatchewan, News Release, "New siting guidelines strengthen environmental protection and clarity for future wind power projects" (19 September 2016).

important bird areas and key Saskatchewan rivers. Project proponents will be required to undertake an environmental and wildlife impact assessment even if a proposed project is located outside these buffer zones.[41]

Windlectric Inc. is currently in the process of reviewing alternative locations for its project. The company has a 25-year power purchase agreement with SaskPower for the project's energy output, and plans to amend that agreement as required.[42]

At this time, it remains unclear whether Saskatchewan will reach its goal of achieving its Wind Capacity Target. While SaskPower has published procurement plans to achieve 15 per cent wind power capacity, commitments have not yet been made regarding financial support or other programs to facilitate the development of an additional required 730-MW of wind power. Similarly, the extent to which Saskatchewan's 50 per cent renewable energy target and likely continued investment in CCS will impact consumer electricity rates remains an open question. While the United States Energy Information Administration estimates that the total levelized cost of wind power will be less than coal by the year 2020 due to the high cost of pollution control mechanisms such as CCS,[43] the actual cost of wind power and its resultant impact on electricity prices in Saskatchewan remains unknown.

ONTARIO

In Ontario, there has been a gradual evolution of climate change policies. The most recent of these policies, a Five-Year Climate Change Action Plan ("ON Action Plan") was introduced in June 2016. The interrelationship between those policies and Ontario's energy supply systems, including Ontario's replacement of all coal-fired electricity generation, has resulted in a significant increase in renewable electricity production in the province, coupled with significant increases in the cost of electricity.

The Greening of Ontario's Electricity Supply Mix

It could be said that Ontario's efforts to combat climate change began in 2005 with the closure of the coal-fired Lakeview Generating Station in order to reduce GHG emissions, and the making in 2007 of a government regulation requiring the cessation of coal-fired generation in Ontario by December 31, 2014.[44] Ontario accomplished that goal when it closed its last remaining coal-fired generator in April 2014 and became the first jurisdiction in North America to fully eliminate coal as a source of electricity generation.[45] Ontario believes that its actions in that regard represent the single largest GHG reduction action in North America.[46]

Another significant step occurred with the passage of the *Green Energy and Green Economy Act, 2009*[47] (the "*Green Energy Act*"). That legislation facilitated the replacement of coal-fired generation in the province with renewable electricity generation by introducing a FIT program, and a procedure whereby renewable energy projects would only need one primary environmental approval, known as the Renewable Energy Approval, in place of various other provincial permit and municipal by-law requirements.

Ontario's FIT program was a government process for procuring electricity from renewable sources, with standard program rules, standard contracts and standard pricing for different classes of generation facilities. The FIT program incentivized the development of renewable generation by offering stable prices under long-term contracts (generally 20 years) for energy generated in Ontario from renewable sources. Renewable sources were defined to include bioenergy (biomass, biogas and landfill gas), wind, solar photovoltaic, and waterpower.

Ontario cancelled the large FIT (generating capacity over 500 kilowatts ("kW")) part of the program[48] in June 2013[49], and replaced it with

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41 Saskatchewan, Ministry of Environment, *Wildlife Siting Guidelines for Saskatchewan Wind Energy Projects,* 2016-FWB 01 (Regina: September 2016).
42 Stefani Langenegger, "Wind project near Chaplin, Sask., denied" *CBC News* (19 September 2016).
43 *Supra* note 32 at 55.
44 Ontario, Ministry of Energy, *The End of Coal* (Toronto: 16 December 2015).
45 Ontario, Ministry of Energy, New Release, "Creating Cleaner Air in Ontario" (Toronto: 15 April 2014).
46 *Supra* note 44.
47 *Green Energy and Green Economy Act, 2009*, SO 2009, c 12.
48 The small FIT program (generating capacity greater than 10 kW, and 250 kW or less if connected to a less than 15 kV line, and 500 kW or less if connected to a 15 kV or greater line), and the microFIT program (generating capacity 10 kW or less) continue to exist.
49 Ontario, Ministry of Energy, *Renewable Energy Program* (Toronto: 12 June 2013).

the Large Renewable Procurement ("LRP") program in 2014. The LRP program was a competitive process for procuring renewable electricity projects larger than 500 kilowatts, and was designed to proceed in multiple phases. Phase one concluded in April 2016 with the execution of approximately 454-MW of renewable power contracts. Ontario announced that it was proceeding with phase two of LRP ("LRP II") in the summer of 2016. However, on September 27, 2016 the Minister of Energy issued an unexpected Directive suspending all further procurement of renewable generation under LRP and putting an end to the LRP II request for qualifications process.[50]

Ontario announced that it suspended the LRP because further procurement of electricity capacity is not needed at this time. Ontario is currently forecast to have a robust supply of electricity for the next decade. The suspension of the LRP is expected to avoid additional spending of $3.8-billion in electricity system costs (reflecting approximately $2.45 per month for a typical residential electricity consumer, relative to previous forecasts).

Ontario's efforts to develop renewable generation capacity have dramatically changed its electricity supply mix over the last decade. Ontario currently has about 18,000 MW of wind, solar, bioenergy and hydroelectricity energy contracted or in development. Renewable energy now comprises 40 per cent of Ontario's installed capacity and generates approximately one-third of the electricity produced in the province. When combined with nuclear resources, which account for one-third of Ontario's installed capacity and produce nearly 60 per cent of its electricity, these non-fossil sources now generate approximately 90 per cent of the electricity in Ontario.[51]

The changes to Ontario's electricity supply system, including the move to renewable energy, have resulted in substantial increases in the cost of electricity in Ontario over the last decade, and public complaints regarding consumer electricity rates have similarly increased in response. When the Ontario government lost a by-election on September 1, 2016, the Premier linked the loss to public frustration over the rising cost of electricity.[52] It is therefore not surprising that when the government suspended the LRP, it made a point of emphasizing the cost savings associated with the decision.[53]

After achieving a substantial reduction in GHG emissions from the generation of electricity, Ontario turned its attention to other ways in which it could reduce GHG emissions. On May 18, 2016 the *Climate Change Mitigation and Low-carbon Economy Act, 2016*[54] ("*Ont CC Act*") was enacted. Since the passage of that legislation, Ontario has launched or expanded a series of initiatives to facilitate meeting its targeted reductions in GHG emissions, including:

- Implementation of a cap and trade regime;
- The ON Action Plan and implementation of related initiatives; and
- The proposed expansion of the Industrial Conservation Initiative ("ICI") intended to reduce peak electricity demand and electricity costs for business.

The *Ont CC Act* and Regulations

The stated purposes of the *Ont CC Act* are to create a regulatory scheme:

- to reduce GHG emissions in order to respond to climate change, to protect the environment and to assist Ontarians to transition to a low-carbon economy; and
- to enable Ontario to collaborate and coordinate its actions with similar actions in other jurisdictions in order to ensure the efficacy of its regulatory scheme in the context of a broader international effort to respond to climate change.

The *Ont CC Act* establishes the following targets for the reduction of GHG emissions as compared to 1990 levels: 15 per cent by the end

50 Ontario, Ministry of Energy, *Large Renewable Procurement (LRP) II and Energy from Waste Standard Offer Program (EFWSOP)*, (Toronto: 27 September 2016).
51 IESO, *Ontario Planning Outlook* (Toronto: September 2016) at 2.
52 Robert Benzie, "Wynne Signals Hydro Relief is Coming for Consumers", *Toronto Star* (7 September 2016).
53 Ministry of Energy, News Release, "Ontario Suspends Large Renewable Energy Procurement" (27 September 2016).
54 *Climate Change Mitigation and Low-carbon Economy Act, 2016*, SO 2016, c 7.

of 2020; 37 per cent by the end of 2030; and 80 per cent by the end of 2050.[55]

The legislation also requires the Ontario Government to prepare a climate change action plan, setting out actions that will enable Ontario to achieve the targets.[56]

Ontario implemented two new regulations: *The Cap and Trade Program Regulation*[57] ("*Cap and Trade Regulation*"), which took effect on July 1, 2016, and *The Quantification, Reporting and Verification of Greenhouse Gas Emissions Regulation*[58] ("*Emissions Regulation*"), which will take effect on January 1, 2017. The Emissions Regulation provide the methodology by which participants in the Cap and Trade Program will quantify and verify their emissions.

Ontario's Cap-and-Trade Regime

The finalization of the *Cap and Trade Regulation* is a significant step in a process that began in April 2015, when Ontario signed an agreement with Quebec to create a joint cap and trade system to reduce GHG emissions.

Under the *Cap and Trade Regulation*, a facility can only emit as much carbon as it has allowances for. One allowance is equal to one tonne of CO_{2e}. The first compliance period will be from January 1, 2017, (when the cap and trade system begins) until December 31, 2020. The total number of allowances for all facilities (i.e. the cap) is provided in the *Cap and Trade Regulation* for the years 2017 - 2020 and will steadily decline each year.

A certain number of allowances will be reserved each year for free distribution to participants. Eligible participants must apply for free allowances in respect of the activities engaged in at each facility and the number allocated will be determined according to the published *Methodology for the Distribution of Ontario Emission Allowances Free of Charge*.[59] Allowances that are not freely distributed will be auctioned. The first auction is scheduled for March 2017. If the amount of CO_{2e} emitted by a facility exceeds its free allowances, it must purchase additional allowances at the auction. Similarly, facilities that emit less than their permitted allowance may sell their unused free allowances at the auction.

All of the proceeds from Ontario's cap and trade system will be allocated to a provincial fund called the Greenhouse Gas Reduction Account and used to fund many of the initiatives under the ON Action Plan.

The cap and trade system will impose certain compliance obligations on Ontario's natural gas distributors, including facility-related obligations for facilities the distributors own or operate, and customer-related obligations for natural gas-fired generators, and certain other residential, commercial and industrial customers. The natural gas utilities will need to develop compliance plans for fulfilling their cap and trade obligations, and they will inevitably incur additional compliance costs.

The Ontario Premier has stated that she expects residential natural gas bills to go up about $5 a month (or $60/year) as a result of the cap-and-trade system. The Premier's prediction is somewhat lower than Union Gas' prediction that natural gas price for homeowners will likely rise by about $70 to $80 in 2017, and that amount is likely to rise in the future.

In the electricity context, the carbon price will only be added to the price of electricity generated in Ontario to the extent that the electricity is generated from a carbon producing source. That means that the carbon price will only be added to the portion of Ontario's supply mix which comes from natural gas-fired generation – approximately 10 per cent in 2015. The carbon price will also be applied to electricity imports to the extent that those imports were generated by fossil fuels. However, the effect on the price of imported electricity may be mitigated if electricity imports to Ontario from low GHG emitting jurisdictions such as Quebec (which produces primarily hydroelectricity) increase and imports from higher emitting jurisdictions (such as Michigan which uses coal for much of

55 *Climate Change Act*, *ibid,* s 6(1).
56 *Climate Change Act*, *ibid,* s 7(1).
57 *The Cap and Trade Program*, O Reg 144/16.
58 *Quantification, Reporting and Verification of Greenhouse Gas Emission*, O Reg 143/16.
59 Ontario, Ministry of the Environment and Climate Change, *Methodology for the Distribution of Ontario Emission Allowances Free of Charge* (Toronto: MOECC,16 May 2016).

its generation) decrease.[60]

It is difficult to predict how the cap-and-trade system will ultimately impact the cost of electricity in Ontario as there are many different factors in play. However, in its September 2016 Planning Outlook report, the Ontario Independent Electricity System Operator ("IESO") suggested that the increasing cost of using fossil fuels, like natural gas (and gasoline in cars), relative to the cost of using electricity, along with Ontario's other climate change actions, may lead to increased demand for electricity and greater electrification of the overall energy system (such as transportation).[61]

The ON Action Plan and Related Initiatives

The ON Action Plan builds on Ontario's Climate Change Strategy previously released in November 2015,[62] which set the long-term vision for meeting GHG emissions reduction targets. The ON Action Plan acknowledges that there is a need to maintain a competitive economy while achieving environmental results. This will be the biggest challenge facing Ontario as it attempts to "up the ante" in its climate change fight.

The ON Action Plan outlines other key actions Ontario is proposing to combat climate change. The goal is to use the proceeds from the cap and trade system to fund green projects and implement elements of the ON Action Plan.

According to the ON Action Plan, Ontario's environmental and clean technology sector is made up of approximately 3,000 firms employing 65,000 people and is estimated to be worth $8 billion in annual revenue and $1 billion in export earnings. There is no doubt that this sector will grow considerably if the ON Action Plan is implemented.

The ON Action Plan outlines Ontario's intention to take numerous actions to introduce new fiscal measures to benefit individual consumers and businesses and at the same time move towards lower emission technologies, including:

- **Create a cleaner transportation system**

  More than 33 per cent of Ontario's GHG emissions are caused by the transportation sector. The ON Action Plan establishes an electric and hydrogen passenger vehicles sales target of 5 per cent in 2020 (in 2015, 5 per cent of the number of cars sold was 14,000 cars). Ontario intends to work with the federal government to eliminate the Harmonized Sales Tax on zero emission vehicles and to increase access to the infrastructure for charging electric vehicles. In July 2016, Ontario announced that it will be building nearly 500 electric vehicle charging stations ("Charging Stations"), to be in service by March 2017. The proposed network of Charging Stations will allow electric vehicles to travel from the City of Windsor in the south of the province to the City of North Bay and to all the major urban centers in the province.

- **Encourage installation/retrofit of clean energy systems**

  Ontario will seek to help homeowners reduce their carbon footprints by supporting additional choice. Ontario intends to invest $100 million from the Ontario Green Investment Fund to help homeowners purchase and install low-carbon energy technologies such as geothermal or air-source heat pumps, solar thermal and solar energy generation. Fiscal incentives will also be introduced to encourage net zero carbon homes and reduce the reliance on the use of natural gas for heating. The province has announced that it is working in partnership with Enbridge Gas Distribution and Union Gas to develop a program to help about 37,000 homeowners conduct audits to identify energy-saving opportunities and then complete retrofits, such as replacing furnaces and water heaters, and upgrading insulation.

- **Keep electricity rates affordable**

  In response to increasing public complaints over the sharp increases in the cost of electricity over the last decade, the ON Action Plan states that Ontario intends to

60 *Supra* note 51 at 18.
61 *Ibid* at 7-8.
62 Government of Ontario, *Climate Change Strategy* (Toronto: 25 August 2016).

keep electricity rates affordable through the use of proceeds from the cap and trade system to offset the cost of GHG reduction initiatives that are currently funded by residential and industrial consumers through their electricity bills.

In its September 2016 throne speech,[63] the Ontario government announced measures to provide homeowners and other eligible consumers with a rebate of the 8 per cent provincial sales tax on the cost of electricity, and a plan to expand the number of businesses eligible to benefit from the ICI (discussed below).

- **Establish a "green bank" to promote the use of Energy Efficient Technologies**

Ontario is proposing to establish a "green bank" to promote the use of energy efficient technologies. Once established, the green bank is intended to accomplish three goals:

1. help households understand and determine what government grants and other incentives are available for each prospective project, and help people calculate payback periods and returns on investments;

2. provide households with assistance to secure flexible low-interest financing to help pay for GHG-reducing energy improvements in their homes – with special provisions to support low and modest income households; and

3. support large commercial and industrial projects, or projects that require scale to be financed privately, by working with commercial banks to help aggregate projects to reduce risk.

- **Manage the fiscal impact of the cap and-trade regime**

Ontario intends to help business and industry manage the impacts of cap-and-trade by supporting significant emission reductions by providing funds to offset the cost of low-carbon technologies, support research and development and provide allowances to industry to help them transition to lower carbon technology while they reduce GHG pollution. These actions to facilitate the transition to a carbon priced economy are laudable but Ontario must be careful to not dilute the effectiveness of the cap-and-trade program by the provision of too many free allowances or offset credits.

Expansion of Ontario's ICI

During its September 2016 throne speech, Ontario announced that it will be expanding its ICI to enable more businesses to access the program.[64] The ICI provides a strong incentive for large electricity consumers to shift their electricity consumption to off-peak hours, and Ontario hopes that the expansion of the program will promote its climate change goals by deferring the need to build peaking generation.

The ICI allows customers to significantly lower their year-round electricity costs by reducing consumption from the provincial grid during times of peak demand. If an ICI participant reduces the amount of power it consumes from the provincial grid during the five hours in a year when the overall demand for electricity in Ontario is the highest (known as "coincident peaks") it will benefit from a reduction in its electricity costs throughout the following year.[65]

While the ICI has been in place since 2011, only certain large industrial customers qualified for the program. Going forward, the ICI will be expanded to include all types of businesses and qualifying average hourly electricity demand will be lowered. More than 300 businesses already use the ICI and Ontario expects that over 1,000 new businesses will be eligible for ICI after the program is expanded.[66]

The Future

In September 2016, Ontario confirmed that

63 Ontario, Office of the Premier, "Speech from the Throne" (12 September 2016).
64 *Ibid.*
65 IESO, "Changes to Class A Eligibility", online: IESO <http://www.ieso.ca/Pages/Participate/Settlements/Changes%20to%20Class%20A%20Eligibility.aspx>.
66 Ontario, Office of the Premier, News Release, "Introducing Measures to Reduce Electricity Costs" (15 September 2016).

it intends to continue implementation of the initiatives highlighted in the ON Action Plan and in the government's September 2016 throne speech.[67]

Since 2010, Ontario has periodically released its Long-Term Energy Plan ("LTEP"). The last LTEP was released in 2013, and another is due to be released in 2017. Ontario will be working to align the 2017 LTEP with the ON Action Plan. The LTEP will be guided by a number of strategic themes including GHG reductions, innovation, grid modernization, conservation and energy efficiency, renewable energy, distributed energy and continued focus on energy affordability for homes and businesses.

The Ontario government will also be working with the IESO to provide, later in 2016, a mid-term review of Ontario's six-year Conservation First Framework, and an update on moving towards meeting Ontario's GHG reduction targets for 2020, 2030 and 2050.

QUEBEC

The 2013-2020 Climate Change Action Plan ("CCAP 2020"),[68] adopted by the previous provincial government, is one of Quebec's main tools to address climate change. CCAP 2020 sets a GHG emissions reduction target of 20 per cent below 1990 levels by 2020. When adopted in 2013, CCAP 2020 encouraged a shift toward a greener economy by establishing a list of thirty priorities to be pursued by the Quebec Government. In order to achieve the GHG emissions reduction target, one of the main mechanisms set forth in CCAP 2020 was to establish a cap and trade system ("Quebec Cap and Trade").

Quebec Cap and Trade

The Quebec Cap and Trade is a flexible, market-based mechanism that allows regulated emitters and other participants to trade GHG emission allowances ("Carbon Credits") in order to respect a cap set by the government. It formally started operating on January 1, 2013 and, one year later, was linked with California, creating the largest cap and trade regime in North America.[69] The ninth Quebec-California carbon market auction will be held on November 15, 2016.

The *Regulation respecting a cap-and-trade system for greenhouse gas emission allowances*[70] ("*Cap and Trade Regulation*") enacted under the *Environment Quality Act*[71] sets out the legal framework governing the operation of the Quebec Cap and Trade. The *Cap and Trade Regulation* applies to an emitter that emits a quantity equal to or exceeding 25,000 megatonnes ("Mt") CO_{2e} per annum in a sector of activity listed under the *Cap and Trade Regulation* (which includes electrical, electricity, mining and fossil fuel distribution sectors).[72]

There are several ways to obtain Carbon Credits under the Quebec Cap and Trade. First, some are freely allocated, auctioned off or sold by the Quebec Government.[73] Second, early reduction credits were allocated for reductions in GHG emissions made from January 1, 2008 to December 31, 2011, as an incentive to reduce emissions prior to the establishment of the Quebec Cap and Trade.[74] Finally, emitters and participants can also obtain offset credits by taking part in emission reduction projects in

67 Government of Ontario, "September 2016 Mandate letter, Environment and Climate Change", (Toronto: 23 September 2016); Government of Ontario, "September 2016 Mandate letter, Energy"(23 September 2016).
68 Government of Quebec, *Quebec in Action: Greener by 2020, 2013-2020 Climate Change Action Plan*, (Quebec : Government of Quebec, 2012).
69 Government of Quebec, *A brief look at the Quebec cap-and-trade system for emission allowances*, online: MDDELCC <http://www.mddelcc.gouv.qc.ca/changements/carbone/documents-spede/in-brief.pdf>. Note also that a Joint Declaration between the Ministry of the Environment and Natural Resources of the United Mexican States, the Government of Ontario, and the Government of Quebec was signed on August 31, 2016 under the terms of which the parties agreed to deepen their collaboration by conducting cooperation activities on carbon markets with the objective of reducing greenhouse gas emissions and jointly promoting the expansion of carbon market instruments for greenhouse gas emissions reduction in North America.
70 *Regulation respecting a cap-and-trade system for greenhouse gas emission allowances*, CQLR, c Q-2, r 46.1 [*Cap and Trade Regulation*].
71 *Environment Quality Act,* CQLR, c Q-2.
72 *Cap and Trade Regulation*, *supra* note 70 at s 2. Note that there is also mandatory reporting under the *Regulation respecting mandatory reporting of certain emissions of contaminants into the atmosphere,* CQLR, c Q-2, r 15 by every person or municipality operating an establishment that, during a calendar year, emits into the atmosphere greenhouse gases in a quantity equal to or greater than 10,000 metric tons CO_2 equivalent.
73 *Cap and Trade Regulation*, *ibid* at ss 39, 45, 56.
74 *Ibid* at s 65.

accordance with the *Cap and Trade Regulation*. Offset credits can also be traded through the system and used for compliance purposes.[75]

At the end of each compliance period (2013-2014, 2015-2017 and 2018-2020), each regulated emitter must have enough Carbon Credits to cover their emissions, either through one of the previously discussed mechanisms or by purchasing credits from another regulated emitter or participant.[76] These transactions must be carried out via the Compliance Instrument Tracking System Service. An annual reduction of the cap and of the freely distributed Carbon Credits ensures a constant reduction of GHG emissions from the regulated entities.[77] The majority of the revenues raised by the government through the Quebec Cap and Trade are earmarked for the Green Fund, established under an *Act Respecting the Ministère du Développement Durable, de l'Environnement et des Parcs*[78], which is dedicated to financing measures or programs intended to promote sustainable development and address climate change. The Green Fund is expected to accumulate approximately $3.3 billion by 2020 with 70 per cent derived from the Quebec Cap and Trade.[79]

Quebec's Emission Reduction Targets

The Government of Quebec has articulated three ambitious and progressive GHG emission reduction targets to be reached by the middle of this century. In addition to the 20 per cent reduction below 1990 levels by 2020, the province has also set targets for 2030 and for 2050.

At the end of November 2015, in anticipation of COP 21, the Government of Quebec confirmed that it would aim to reduce emissions by 37.5 per cent below 1990 levels by 2030. This is the most ambitious target set to date in Canada.[80]

Finally, as a signatory to the Subnational Global Climate Leadership MOU, an agreement that brings together subnational jurisdictions in order to further reduce GHG emissions, Quebec has committed to either reduce its GHG emissions by 80 per cent to 95 per cent, or limit GHG emissions to 2 $MtCO_{2e}$ per capita per year, by 2050.[81]

Recent Developments

Two of the more important recent regulatory developments in Quebec in the energy and climate change sectors include the Transportation Electrification Action Plan 2015-2020[82] ("QC Action Plan") and the 2030 Energy Policy[83] ("Energy Policy"). In addition, related draft legislation has been recently tabled in the Quebec National Assembly, including Bills 102, 104, and 106.

Bill 102

On June 7, 2016, of Bill 102 – *An Act to amend the Environment Quality Act to modernize the environmental authorization scheme and to amend other legislative provisions, in particular to reform the governance of the Green Fund*[84] ("Bill 102") was presented. Bill 102 seeks to amend the *Environment Quality Act*[85] in order to modernize the permitting process. The proposed changes would, *inter alia*, provide for a new ministerial authorization scheme which would allow the Minister to take into

75 *Ibid* at ss 37, 70.1 ff.
76 Government of Quebec, *supra* note 69.
77 *Ibid*.
78 *An Act Respecting the Ministère du Développement Durable, de l'Environnement et des Parcs,* CQLR, c M-30.001, s 15.1 and ff.
79 Government of Quebec, *Fonds vert– Secteur d'activité : Changements climatique*, online : MDDELCC <http://www.mddelcc.gouv.qc.ca/ministere/fonds-vert/secteurs/Changements-climatiques.htm#provenance>.
80 Radio-Canada, « Réduction des GES : Quebec vise 37,5 % d'ici 2030 », *Radio-Canada* (27 November 2015), online : <http://ici.radio-canada.ca/nouvelles/environnement/2015/11/27/003-quebec-ges-gaz-effets-de-serre-2030-objectif-reduction-environnement.shtml>.
81 Global Climate Leadership, *Memorandum of Understanding (MOU)*, online: <http://under2mou.org/wp-content/uploads/2015/04/Under-2-MOU-English.pdf>.
82 Government of Quebec, *Propelling Quebec forward with electricity*, online: < http://www.transportselectriques.gouv.qc.ca/en/>.
83 Government of Quebec, *Energy in Quebec, a source of Growth –The 2030 Energy Policy*, 2016 [*The 2030 Energy Policy*].
84 Bill 102, *An Act to amend the Environment Quality Act to modernize the environmental authorization scheme and to amend other legislative provisions, in particular to reform the governance of the Green Fund*, 1st Sess, 41th Leg, Quebec, 2016.
85 *Supra* note 71.

account the GHG emissions attributable to a project and assess any climate change impact mitigation and adaptation measures proposed when deciding whether or not to grant an authorization.

QC Action Plan

The QC Action Plan, which was presented by the Quebec Government on October 9, 2015, aims to create a structure and define the steps to be taken in order to establish Quebec as an "electric transportation leader and sustainable mobility trailblazer" by 2020.[86] In that regard, the QC Action Plan follows three policy directions: (1) to encourage electric transportation; (2) to build an industrial base (including research and development of the manufacturing sector); and (3) to create the right environment (an appropriate legal and regulatory framework). The electrification of transportation is also presented by the Government of Quebec as an opportunity to develop the mining sector.

In order to help achieve a 20 per cent reduction of GHG emissions below 1990 levels by 2020, as set out in the CCAP 2020, the QC Action Plan comprises 35 different measures financed by a $420 million investment provided by the Government of Quebec, mostly coming from the Green Fund discussed above. More specifically, the following targets have been set for 2020:

1. 100,000 plug-in electric and hybrid vehicles will be registered in Quebec (in the Energy Policy the Government also announced an even more ambitious target of reaching 300,000 electric and hybrid vehicles registered in Quebec by 2026 and 1,000,000 by 2030, which would represent approximately 20 per cent of all light-duty vehicles);

2. Reduce the annual GHG emissions produced by transportation by 150,000 tonnes;

3. Reduce by 66 million the number of litres of fuel consumed annually in Quebec; and

4. 5,000 jobs in the electric vehicle industry will be created and $500 million of investments will be generated.

The Government of Quebec recently moved forward with its first regulatory initiative following the release of the QC Action Plan. On June 2, 2016, the Minister of Sustainable Development, the Environment and the Fight Against Climate Change ("MDDELCC" for the French name of this Ministry, le ministère du Développement durable, de l'Environnement et de la Lutte contre les changements climatiques) introduced Bill 104 – *An Act to increase the number of zero-emission motor vehicles in Québec in order to reduce greenhouse gas and other pollutant emissions* ("Bill 104").[87]

Bill 104

Bill 104 aims to increase the number of zero-emission motor vehicles in Quebec. More precisely, it "establishes a system of credits and charges applicable to the sale or lease in Quebec, by motor vehicle manufacturers, of new motor vehicles". The scope of Bill 104 is limited to motor vehicle manufacturers that, on average, for three consecutive model years, sell or lease more than 4,500 new motor vehicles in Quebec.

Credits accumulate by selling or leasing new motor vehicles that respect certain conditions (such as being completely or partially electrically propelled, using a battery or a cell that is rechargeable from a source that is not on board the vehicle). A manufacturer can also obtain credits by acquiring them from another motor vehicle manufacturer. Under Bill 104, motor vehicle manufacturers that do not accumulate enough credits, as determined and calculated by regulation, will have to pay a charge to the MDDELCC, which amount will be credited to the Green Fund.

Special consultations on Bill 104 were held in August of 2016 before the Committee on Transportation and the Environment and the Bill was adopted in principle on September 22, 2016. Due to the generality and the regulatory discretion contained in Bill 104, the consequences of the Bill will only be fully understood once the regulations come into effect.

86 *Supra* note 82.
87 Bill 104, *An Act to increase the number of zero-emission motor vehicles in Quebec in order to reduce greenhouse gas and other pollutant emissions*, 1st Sess, 41th Leg, Quebec, 2016.

The Energy Policy

On April 7, 2016, the Government of Quebec announced the Energy Policy which, by 2030, seeks to make Quebec a North American leader in the fields of renewable energy and energy efficiency by building a strong low-carbon economy. More precisely, the Energy Policy sets forth the following five targets to be achieved by 2030:

1. Enhance energy efficiency by 15 per cent;
2. Reduce the amount of petroleum products consumed by per cent;
3. Eliminate the use of thermal coal;
4. Increase overall renewable energy output by per cent; and
5. Increase bioenergy production by 50 per cent.

In addition to these ambitious targets, the Energy Policy has also introduced other significant developments. The Government of Quebec will establish a new agency devoted to energy conservation and to energy transition and has indicated that it will be broadening the powers of the Régie de l'énergie (the "Energy Board"). Also, a review of the environmental evaluation process applicable to energy projects will be conducted with the view of increasing coherence and coordination between the different authorities that play a role in the environmental, social and economic factors of a given project. In addition, the Energy Policy aims to develop a new approach to hydrocarbon exploration and exploitation in Quebec. Finally, Quebec Government intends to adopt legislation in order to completely eliminate thermal coal as an energy source by 2030.

Bill 106

The Energy Policy will be implemented through the publication of three action plans (2016-2020, 2021-2025 and 2026-2030) and will require several amendments to the existing regulatory framework. In this regard, on June 7, 2016, Bill 106 – *An Act to implement the 2030 Energy Policy and to amend various legislative provisions* ("Bill 106") was introduced by Pierre Arcand, Minister of Energy and Natural Resources.[88]

Bill 106 aims to implement the measures announced in the Energy Policy which will bring about significant changes to the energy regulatory landscape in Quebec.

First, Bill 106 introduces the *Act respecting Transition énergétique Québec* which, once adopted, will establish a new government agency entitled Transition énergétique Québec ("TEQ"), which will be responsible for creating all programs and taking the necessary measures to meet the energy targets set forth by the government. TEQ will notably be responsible for preparing an energy transition, innovation and efficiency master plan every five years and will be required to consult with relevant stakeholders, as specified under the Act. The master plan is to be submitted to the Government of Quebec and to the Energy Board for adoption, if it is considered to be consistent with the government's objectives. The Green Fund and annual contribution from energy distributors will jointly finance TEQ.

Second, Bill 106 sets out amendments to the *Act respecting the Régie de l'énergie*.[89] In addition to its new role with respect to the approval of TEQ's master plan, Bill 106 also contains provisions concerning the distribution of renewable natural gas and the inclusion of excess transmission capacity in a natural gas distributor's supply plan.

Third, Bill 106 introduces amendments to the *Hydro-Québec Act*[90] that, once adopted, will provide Hydro-Québec with the power to grant financial assistance to public transit authorities and public bodies for the fixed equipment necessary for the electrification of shared transportation services.

Finally, Bill 106 proposes the enactment of the *Petroleum Resources Act*, which aims to govern the development of petroleum resources in Quebec. Currently, this sector is governed by

88 Bill 106, *An Act to implement the 2030 Energy Policy and to amend various legislative provisions*, 1st Sess, 41th Leg, Quebec, 2016.
89 *Act respecting the Régie de l'énergie,* CQLR, c R-6.01.
90 *Hydro-Québec Act,* CQLR, c H-5.

the *Mining Act*[91] In its current form, Bill 106 creates a license and authorization system for the exploration, production and storage of petroleum resources and enhances the role of the Energy Board. New exploration licenses would be allocated by auctions. It also includes provisions addressing closure and site restoration plans. Petroleum royalties, in addition to other sums, would be paid to the Energy Transition Fund, also created by Bill 106.

Special consultations were held in August of 2016 before of the Committee on Agriculture, Fisheries, Energy and Natural Resources. The Report of the Committee was presented before the Quebec National Assembly on September 20, 2016. Bill 106 has not yet been put to a vote and, taking into account the significance of the reform, may be subject to amendments before adopted.

Energy Implications

Contrary to other Canadian provinces, the policy and regulatory shift discussed throughout this section will not have a significant impact on the balance of energy sources in Quebec. Indeed, the abundance of hydroelectric power in the province allows Quebec to generate more than 99 per cent of its electricity through renewables.[92] That stated, the policies and regulatory changes described above will have other impacts.

Although the heightened regulatory activity is not expected to significantly impact the type of energy sources in Quebec**,** carbon policies will likely translate into additional costs for consumers and businesses. As estimated by the government and the oil industry, the price of one litre of gasoline has increased somewhere between 2 to 3.5 cents as a result of the implementation of the Quebec Cap and Trade.[93] In 2015, the average natural gas consumer (2,300 m^3/year) saw an increase of $41/year for his/her gas consumption and the average business (14,600 m^3/year) saw an increase of $258/year.[94]

As suggested by the Ontario IESO, regulatory pressure on the cost of carbon could lead to a greater electrification of the energy grid and drive up demand for electricity.[95] As discussed in the Energy Policy, Hydro-Québec, the most important Quebec power utility, is expected to take advantage of such a favorable context and attempt to further extend its reach outside of the province. In order to achieve its intention to double its revenues over the next fifteen years, Hydro-Québec has indicated that it will be seeking to increase its electricity exports to other markets and use its valuable know-how to increase its presence abroad.[96]

In light of the foregoing, it is clear that Quebec is at a crucial stage in the development of its legal framework relating to climate change and energy development. By establishing ambitious targets related to the reduction of GHG emissions and the number of registered electric vehicles, Quebec has set the bar high for the upcoming years. The Bills recently tabled before the Quebec National Assembly and discussed in this article can be characterized as setting the stage for an era of energy transition. The practical impacts of this shift to a greener Quebec are still unpredictable, however we can expect a greater pressure on consumers of carbon intensive products and an enhancement of the role played by Hydro-Quebec in other provinces and in the United States.

CONCLUSION

As described in this article and summarized below, the GHG regimes and policies adopted by the Big-Five provinces are quite varied, as are their impacts on electricity production and prices:

B.C. has traditionally generated the majority of its electrical power from hydroelectric projects. As a means of reducing its GHG emissions, in 2012 it adopted a broad-based carbon tax, which is set at $30/tonne. As a supplement to its carbon tax, B.C. will also be implementing emissions-intensity performance standards for prescribed industries. To date B.C.'s GHG

91 *Mining Act,* CQLR, c M-13.1.
92 The 2030 Energy Policy, *supra* note 83, at 16.
93 Ministry of the Environment and Climate Change of Ontario, *Backgrounder –How Cap and Trade Works* (Toronto: 13 April 2015), online: <https://news.ontario.ca/ene/en/2015/04/how-cap-and-trade-works.html>.
94 Gazifere, *Introduction des droits d'émission de carbone sur la facture au 1er janvier 2015*, online : <http://www.gazifere.com/wp-content/uploads/2014/12/Info-Marche-du-carbone-dec-2014R.pdf>.
95 *Supra* note 61 at 7-8.
96 The 2030 Energy Policy, *supra* note 83, at 22.

emissions reduction policies have had minimal impact on electricity prices, presumably because those policies have had limited impact on its production of hydroelectric power.

Alberta has traditionally relied on coal for the majority of its power production. It also has extensive oil and gas operations which traditionally have high GHG emissions, particularly in the oil sands regions. Alberta has had an emissions intensity regime in place for large emitters for almost a decade. Beginning in 2017, it is expanding its carbon regime to encompass other businesses and consumers through the implementation of a carbon levy. By 2018, the levy will be set at $30/tonne and thereby mirror B.C.'s carbon tax. It is also phasing out all coal-fired power production and making a concerted effort to replace a significant portion of that power generation with renewable energy production. Finally, it is placing an absolute cap on oil sands emissions. As for the potential impact on electricity prices, it is still too early to tell, although there is a potential for prices to rise due to the additional costs associated with constructing additional necessary transmission infrastructure and transitioning into a higher reliance on renewable energy.

Saskatchewan is similar to Alberta in that it relies on coal for the majority of its power production. It also has extensive oil and gas and mining operations and is the highest provincial emitter of GHG emissions on a per capita basis. To date Saskatchewan appears to be a bit of an outlier when it comes to GHG emissions reduction policies. Instead of implementing extensive GHG reduction measures or moving towards the phasing out of coal-fired power plants, the government of Saskatchewan has concentrated on supporting CCS initiatives. Although SaskPower, Saskatchewan's provincially-owned utility company, has committed to achieving 50 per cent renewable energy capacity (of which 30 per cent is to be from wind power) by 2030, it is unclear how it will reach that target. Because of Saskatchewan's limited approach to date, it is difficult to determine the impact, if any, its GHG emissions policies have had or will have on electricity costs.

Unlike its provincial counterparts, Ontario relies on nuclear energy for the majority of its electrical power production. It has adopted a cap-and-trade regime as its preferred means of reducing GHG emissions. Ontario's first compliance period is set to begin as of January 2017. As a supplement to its cap-and-trade policy, Ontario eliminated all power production from coal-fired power plants as of 2014. Since then it has been the most active province in promoting renewable energy projects, having implemented a variety of incentive programs over the years. More recently it has introduced policies in support of the reduction of GHG emissions in the transportation industry. In that regard, it announced it will be building nearly 500 Charging Stations along its highways, which are expected to be in service by March of 2017. Of all the Big-Five provinces, Ontario's GHG emissions reduction policies have had the most significant impact on electricity prices. The impact has been so dramatic that the government blamed the loss of a by-election held in September of 2016 on public frustration over the rising cost of electricity. It is unlikely that there will be any significant reduction in electricity prices and it will be interesting to see if the province is able to constrain additional increases in the future.

Quebec is similar to B.C. in that it generates the majority of its electricity from hydro-power. Quebec is also a cap-and-trade jurisdiction, with the first compliance period having occurred in 2013-2014. Indeed, in 2014 Quebec linked itself with California, creating the largest cap-and-trade regime in North America. More recently, in 2015, Ontario confirmed it was aligning itself with Quebec's cap-and-trade regime. Finally, in a manner similar to Ontario, Quebec has introduced policies and draft legislation that strongly support the reduction of GHG emissions in the transportation industry, including sales targets for electric and hybrid vehicles. With respect to the impact of its GHG emissions reduction policies on electricity costs, there appears to have been minimal effect. Presumably this is because, like B.C., those policies have had limited impact on its production of hydroelectric power.

The wide-ranging GHG emissions reduction policies that the Big Five provinces have employed are an excellent example of how one-size-does-not-fit-all when it comes to this vexing issue. The disparate policies will certainly test the federal government's resolve when it determines if they are otherwise stringent enough to meet the federal targets and thereby sufficient to avoid the imposition of the federal carbon pricing regime in 2018. ■

CAP AND TRADE IN ONTARIO: LESSONS FROM EUROPE

*Jason Kroft and Sam Dukesz**

The European Union Emission Trading System (EU ETS) is the world's largest cap and trade system, covering all countries in the European Union. It is also one of the world's most troubled, as it has largely failed to live up the expectations of emissions reductions that it was initially touted to bring about. This article analyzes the impediments to the success of EU ETS, and then provides a forward-looking analysis of the applicability of those impediments to the proposed Ontario cap and trade program.

European Design and Implementation Problems

The EU ETS was initially implemented in phases, with a pilot Phase I from 2005-2007, followed by a Kyoto Phase II from 2008-2012 and a number of subsequent phases.[1] The initial system covered approximately half of EU CO_2 emissions across 31 EU countries. The system was limited to certain sectors, as many sectors, such as transportation, were exempted because of concerns about competitiveness with non-participating jurisdictions.

The initial process for setting caps on emissions was decentralized by member states, which created strong incentives for individual states to propose high cap limits that favored emission intensive industries in their jurisdiction. This, combined with weak emissions data, led to an overly generous allocation of allowances relative to emissions when the market opened in 2005.

While the price of allowances was initially high, the oversupply in the market quickly depressed demand and prices, causing the price of a single allowance to drop from €30 in 2005 to effectively €0 by 2007. This price drop was exacerbated by the inability to hold allowances over multiple phases in the EU ETS, which guaranteed that the price of an allowance earned in any particular phase would go to zero at the end of that phase. As further aggravation on a strained system, there was some suggestion that companies were passing on the 'costs' of allowances to the end consumer even where they had been given free allowances by the government.

The EU responded in subsequent phases with a planned tightening and centralization of the cap, an expanded scope on covered industries, and an ability to bank allowances between phases. While this initially increased allowance prices to over €20, prices have continued to bottom since that point. The current price varies between €0 and €10. This is in part due to a combination of a weakened post-recession EU economy and the increased use of offsets under the Clean Development Mechanism, which grants allowances for offset projects in developing countries.

Lessons for Ontario

In creating a cap and trade program, there are a number of lessons the Ontario government can apply from the mixed successes of the EU ETS. Each of the key lessons are listed below.

Addressing Over-Allocation

First, it is crucial to avoid over-allocation

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1 *EU ETS Handbook* (Brussels : European Commission), online : EC <http://ec.europa.eu/clima/publications/docs/ets_handbook_en.pdf>.

of allowances in the inception of a cap and trade program; as such over-allocation can be banked by companies to keep the price of allowances low for years to come. Avoiding such over-allocation requires that the Ontario government has good data on emissions in Ontario on which to base an initial cap. Over the past several years, the Ontario government has been collecting emissions data from companies that release more than 10,000 tonnes of GHG a year or are involved in particular industries. This data has led the Ontario government to set an initial cap of 142 megatonnes of GHG, which is presumably equivalent to what the government believes actual emissions will be in 2017. In other words, the Ontario government is anticipating that there will be no over-allocation of emission allowances. Only time will tell if this anticipation proves true.

Banking Allowances

Second, the Ontario government should ensure that companies can bank allowances over multiple periods in the program. While such a model can exacerbate the negative effects of allowance over-allocation, it is necessary to avoid an external collapse of allowance prices at the end of a given period. Such a model is currently in place in the regulations of the Ontario government's cap and trade program, where one may submit allowances with a vintage year that is in the year of the compliance period or an earlier year.

Limiting Free or Exempt Allowances

Third, while granting free allowances to certain sectors can be politically palatable, it is a risky way to deal with issues of competitiveness. When allocations are not linked to production, they cannot affect marginal costs, which eliminates incentives to reduce or relocate emissions for entire sectors. The government may be better served by including these sectors in the cap and trade program in some manner that maintains the incentives applied to other companies, but does so in a more gradual fashion. Anecdotally, we believe many industries will be allocated free allowances towards the start of the cap and trade program in order to ease the transition to a low-carbon economy. These free allowances will somewhat dis-incentivize the need to address climate change in the short run.

Robust Offset Rules

Fourth, offset policies must be properly monitored and maintained. The increasing popularity of the Clean Development Mechanism lies in its allowing companies to apply for offsets when they reduce emissions in foreign jurisdictions. These jurisdictions, which are often third-world countries, lack the regulatory and reporting structures to adequately confirm these emission reductions. Unsurprisingly, the Clean Development Mechanism has been rocked by allegations of fraud by participating companies. The Ontario government should ensure that their offset program is heavily monitored and controlled, especially where the applicable offset reduction takes place in a foreign jurisdiction. The Ontario government has not yet released an offset regimen for its cap and trade program. However, it will likely take guidance from Quebec and California. These programs both have strong oversight requirements to ensure that actual offset reductions are taking place. The Ontario government will likely adopt similar requirements.

Coordinating Complimentary Policies

Lastly, some authors have suggested that the issues with the EU ETS are caused by complementary EU environmental policies related to the cap and trade program. These policies, in the view of their critics, relocate emissions, increase emissions reduction costs, and, in the absence of a price floor, depress allowance prices. This is a complex issue that would require further analysis. That said, there are a number of things the Ontario government can do to prevent this potential issue. First, it has installed a price floor on allowance auctions, which should ensure that the price of allowances is not driven to zero. Second, it can confirm that complementary policies are addressing emissions not covered by the cap and trade program, thereby ensuring that the programs are fully complementary and not serving as impediments to the cap and trade program, or vice versa. ■

RENEWABLES AND ALBERTA'S ELECTRICITY MARKETS: SOME EUROPEAN LEARNINGS

Kalyan Dasgupta and Simon Ede[1], with Leonard Waverman[2]

Renewable energy mandates often accompany ambitious decarbonization policies such as Alberta's recently announced Climate Leadership Plan. European experience shows that such mandates which generally include subsidized renewables (with near zero short-run marginal costs) can reduce conventional thermal generation facilities' utilization rates. Importantly, when utilization rates fall, this reduces the economic viability and the incentives to invest in conventional thermal capacity. These diminished investment incentives sit uneasily beside the fact that some—perhaps substantial—thermal generation capacity will always be required to meet demand: the wind does not always blow and the sun does not always shine. Lower prices and profits in the wake of introducing renewables might drive out some thermal capacity from the market. If this results in demand running ahead of supply, economic theory suggests that prices should rise again to induce thermal generation entry to meet demand. However, the economic literature has identified many factors—especially regulatory intervention and technological limitations—that mean that wholesale prices in electricity markets might not always provide adequate signals of scarcity. Available evidence suggests that subsidized renewables exacerbate this signaling problem. Capacity might not always be built just when it is needed.

In some electricity markets in Europe and the United States, regulators have instituted capacity markets or other mechanisms (including "command and control" mechanisms) that explicitly pay generators for making capacity available. This contrasts with Alberta's "energy-only" market where generators are only paid for the sale of electricity. The impact of renewables has contributed to Europe's growing concerns about long-run capacity investment. Interest in capacity mechanisms has correspondingly grown. The evidence that capacity mechanisms actually achieve their intended results, however, is unclear.

The need to provide thermal generation investors with higher and more certain prices to offset (renewables-induced) lower and less certain utilization further motivates interest in capacity mechanisms. But evidence from the country that has the most clear-cut capacity problem—the United Kingdom—shows that regulators continue to find high prices difficult to accept and to commit to. Regulatory recalcitrance means that capacity mechanisms may not achieve their intended results. Investors faced with current low electricity prices and a history of regulatory intervention to protect consumers from price spikes—even when such spikes stem not from the exercise of market power but from a genuine scarcity of generation resources—might well steer clear of investing in additional thermal generation.

Will renewables create similar challenges in Alberta's electricity markets? Ensuring that the lights stay on even when wind (the

1 Berkeley Research Group LLC.
2 DeGroote School of Business, McMaster University. The opinions expressed in this paper reflect the views of the authors, not the corporate views of Berkeley Research Group or McMaster University, or the views of other individuals associated with these institutions. Responsibility for errors and omissions rests solely with the authors. We are indebted to Matthew Barmack for providing comments on this paper.

predominant renewable source in Alberta) generation is not available, means that meeting system contingencies requires as much thermal capacity in the future as is currently required.[3] Retirement of coal plants means that a large amount of gas-fired generation (CCGTs and peaking facilities) will be needed to replace the coal. But these facilities will likely need to recover their costs—including substantial fixed costs—over fewer and more uncertain hours of operation in order to ensure that they are built. Under current Alberta plans, there will be a substantial period of time in which growing quantities of renewables coexist with substantial remaining coal capacity. While this means no immediate adequacy problem, it also presents a risk that depressed short-term pricing complicates investment in capacity required for the medium-term and long-term. Thermal generation investors will need to be confident that prices will rise *when* the new capacity they are constructing comes on the market, and by enough to accommodate lower and less certain hours of operation. This confidence is particularly important given that forward contracting in electricity markets does not yet provide a sufficient hedge against medium to long-term price risks.

This confidence could prove elusive if there is uncertainty about the retirement schedule of coal capacity; or if there is uncertainty about the quantity of renewables being procured in the future. Renewables mandates have sometimes been revised and expanded in Europe; anticipation of similar actions in Alberta could send precisely the wrong investment signal to investors. Greater certainty about coal and renewable quantities in the future likely assists investment in thermal generation. Abandoning the current price cap so that prices can rise to levels consistent with economic estimates of scarcity value at super-peak hours could also help. Of course, Alberta could institute capacity auctions or other mechanisms that effectively constitute contracts between the system administrator and generators specifically for capacity. But these mechanisms probably require significant institutional investment in their design; require considerable institutional discipline and commitment to function effectively; and may represent a substantial expansion in the extent to which market outcomes are no longer determined by the market, but by a patchwork of administrative interventions.

The initial wave of electricity restructuring in the late 1990s and 2000s in Alberta and elsewhere emphasized markets or market-like incentives to facilitate consumer choice, innovation and cost efficiency. Market prices were intended to provide the right signals about what capacity got built, and when. Climate change policies need not fundamentally alter this: many economists would prefer to let carbon pricing and emissions trading alone achieve the desired level of carbon abatement. But renewables policies, consistent with carbon abatement but wider-ranging in their socio-economic goals[4], are here to stay. Given these policies' focus on achieving an arbitrary penetration target for renewables and the subsidies involved, such policies are inherently not market-compatible. The market no longer chooses what gets built and when. It may be possible to engineer interventions that bring forth adequate investment, but it is doubtful that the energy-only market will continue to be central to achieving this investment. Indeed, if the process is mismanaged, renewables might fundamentally break this market and like Humpty-Dumpty, it may be impossible to put the market back together again.

Early and detailed consideration of renewables' impact on adequacy and on investment incentives ought to be an important focus for Alberta's efforts to adapt its electricity sector to the Climate Leadership Plan. We hope that highlighting European experience will facilitate the process.

Missing Money and Scarcity Pricing

In energy-only markets, such as Alberta's,[5] suppliers must earn profits that are sufficient to

3 The Alberta Electricity System Operator (AESO) currently assigns a zero rating to wind capacity in calculating the availability of a supply cushion to meet contingencies. See Alberta Electric System Operator, "Long-Term Adequacy Metrics" (August 2016) at p 10.

4 These policies are frequently described as "complementary" to carbon pricing and emissions trading, but are best understood as having goals such as attracting investment, fostering innovation, and boosting economic development that go beyond mere carbon abatement. This paper does not comment on the overall desirability of renewables.

5 Alberta operates both a real-time market and a day-ahead market (the latter for ancillary services). There is some use of financial instruments—e.g., forward contracts—by market participants, but our understanding is that forward market volumes are relatively small. Alberta's expectation is that market participants can exchange electricity on non-

cover the fixed costs associated with providing generation capacity, through the prices that they face in the power pool.[6] Typical real-time markets rely on a relatively heterogeneous mixture of generating resources, with significant variation in the marginal costs of dispatch as between, say, a coal plant and a simple-cycle gas-fired peaking facility. This heterogeneity of resources generates an upward-sloping supply curve for electricity, with the market clearing price set by the marginal cost of the last unit dispatched when capacity equals or exceeds demand. There are infra-marginal producers who earn "quasi-rents"[7] based on the fact that they receive a market clearing price that exceeds their own marginal cost. In peak demand hours, when demand bumps up against capacity constraints, prices should rise steeply. Since the demand side of electricity markets, to date, is generally inflexible (as most end-use customers do not or cannot react to real-time prices), prices ought to rise towards the "value of lost load" (what customers would be willing to pay to avoid service curtailment). Although generator profits rise sharply in these circumstances, profits earned from these "scarcity hours" might be critical to generators' ability to recover fixed costs and earn a return on capital.[8] This is likely particularly true for high and intermediate-cost generation facilities which operate for only a few hours each year. Economists and others believe that robust scarcity pricing signals are essential to ensuring long-term investment and thus long-term generation adequacy.

However, many electricity markets in North America have not let market forces entirely determine the price, at peak hours. For example, Hogan states:

"The missing money problem arises when occasional market price increases are limited by administrative actions such as offer caps, out-of-market calls, and other unpriced actions. By preventing prices from reaching high levels during times of relative scarcity, these administrative actions reduce the payments that could be applied towards the fixed operating costs of existing generation plants and the investment costs of new plants."[9]

Alberta imposes a price cap on offers of $999.99 per MWh[10], similar to many other North American jurisdictions. Joskow describes the typical $1000 per MWh price cap used in many U.S. jurisdictions as being "clearly below what the competitive market clearing price would be under most scarcity conditions."[11] He also describes other aspects of electricity markets that create the "missing money" problem—which he defines as wholesale markets producing total revenues that are too low to support investment in an efficient (least-cost) portfolio of generating capacity: for example, demand that does not respond to real-time prices, resulting in actions taken by regulators such as "must offer" obligations to control price spikes;[12] "out of market" calls; and voltage reductions to avoid rolling blackouts in times of scarcity.[13]

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discriminatory terms and manage spot market volatility through appropriate use of financial instruments. Although Alberta has some ex-ante limits on generators' market power (e.g., a $999.99 per MWh bidding cap and a limit on any one firm controlling more than 30 per cent of generation capacity), the mere exercise of market power ("extraction") is not censured.

6 The term "power pool" is used to reflect Alberta's specific circumstances.

7 In this context, quasi-rents are defined as the margins that firms need to earn to pay back the fixed costs incurred in providing generation capacity.

8 If demand is elastic and participates in wholesale markets, then the marginal flexible load might require a payment close to VOLL to curtail voluntarily. This marginal load will set the market price.

9 William W. Hogan, "Electricity Scarcity Pricing through Operating Reserve", (2013) 2:2 Economics of Energy and Environmental Policy at 1.

10 Since Alberta expressly does not censure the mere exercise of generator market power, both scarcity rents and monopoly rents are potentially available to generators. Monopoly rents are earnings in excess of long-run average cost (i.e., more than what is required to generate a normal return on capital) by firms that are able to materially influence the market price by their choice of output (or in the context of the power pool, their bidding strategy). By contrast, scarcity rents are consistent with competitive markets, with scarcity pricing signaling the opportunity cost to society of not providing generation capacity in hours of scarcity. It is erroneous to conclude that economic withholding—the exercise of market power usually causing *too little output* to be supplied to the market—is an offset to scarcity rents in peak hours. In any case, incentives to withhold are highest at times of scarcity.

11 As an example: London Economics on behalf of the UK Department of Energy and Climate Change investigated VOLL across different customer segments and found a load weighted average of £16,940 (roughly $29,000 at current exchange rates) for domestic and small/medium sized commercial customers for peak winter workdays in Great Britain. See London Economics, *The Value of Lost Load (VOLL) for Electricity in Great Britain* (London: London Economics, 2013) at p 54.

12 These obligations reflect regulators' concerns that scarcity conditions, in the presence of a vertical demand curve, present inviting opportunities to exercise market power by withholding supply from the market.

13 Paul L. Joskow, "Capacity Payments in Imperfect Electricity Markets: Need and Design" (2008) 16:3 Utilities Policy at 16-18.

Additionally, at times of peak system demand, with little real-time price response, prices may not increase—as economic efficiency suggests that they should—to reflect the willingness of consumers to pay to avoid curtailment rather than the marginal cost of the last generator dispatched.[14] Hogan describes this facet of conventional energy-only markets as a *de facto* price cap.[15]

Renewables: Merit Order and Market Power Effects

The economic literature identifies two theoretical and mutually offsetting effects of introducing large quantities of renewables into the generation mix:

A price-depressing Merit Order Effect. This effect arises because a large quantity of zero-marginal cost renewables are added alongside low-marginal-cost base-load and higher-marginal-cost energy sources such as CCGTs and simple cycle peaking facilities. The effect of this is to shift out the supply curve to the right, and by doing so, depress the market-clearing price for any given level of demand. In economic terms, renewables (absent withdrawal of other capacity from the market) can substantially reduce the quasi-rents available to existing conventional facilities. This might exacerbate the perhaps inherent scarcity pricing problems associated with current electricity markets.[16]

A price-enhancing Market Power Effect. Many generation markets are at least somewhat concentrated. In these concentrated markets, if conventional thermal generation owners are also diversified into renewables, they may have enhanced incentives to withhold supply from the market *if those renewables receive market prices*.[17] Each generator is a monopolist on its own "residual" demand curve and will trade off elevated profits on infra-marginal units against lost sales of marginal units. Withholding (economically or physically) supply of otherwise "in-merit" facilities induces a higher market-clearing price and thus higher rents on infra-marginal facilities, most especially renewables. Even though renewables have well-known intermittency issues and even though forward markets theoretically mitigate incentives to exercise market power, the economic literature shows that diversified firms will have increased incentives to exercise market power when renewables are introduced into the market.[18]

In the European setting, the empirical literature unambiguously supports a dominant merit order effect (we discuss this in the following section). This may be linked to many countries' choices (in

14 "Conventional" markets have lacked one of the desired features of an efficient, idealised energy-only market: demand-side response. See Joskow, *supra* note 13 at 161, for a description of the four conditions that characterize an energy-only market that does not suffer from the "missing money" problem. One of these conditions is that there are both price-sensitive and price-insensitive consumers. Another is that retailers can offer consumers contracts that specify the conditions under which they can be rationed. Historically, at least, real-time metering technology has not existed to satisfy these conditions.

15 William W. Hogan, *On an 'Energy-Only' Electricity Market Design for Resource Adequacy* (Cambridge: Havard University, 2005), online: <https://www.hks.harvard.edu/fs/whogan/Hogan_Energy_Only_092305.pdf >. In theory, it should be possible to construct an appropriate demand curve for operating reserves and thus offset the missing money problem by effectively "completing the market". Hogan writes: "The absence of an appropriate operating reserve demand curve is one of the difficulties in market design that result in de facto price caps and missing money". He adds, however, that if the "reserve demand curve does not raise prices towards VOLL (the value of lost load) when operating reserves approach the minimum then the demand curve is not capable of representing… the true opportunity cost at the margin".

16 Looked at another way, renewables reduce thermal generation facilities' average utilization rates. Theoretically, prices could rise by enough in the hours when such facilities actually operate that it could offset the lower utilization rates. This scenario likely requires the retirement of substantial amounts of existing capacity and relaxed regulatory policies towards high or even very high peak or super-peak prices. As discussed below, this has not happened in Europe.

17 In many markets in the US and Europe (and in Ontario), however, renewables are effectively under long-term contracts or feed-in tariffs that do not face spot market pricing.

18 Acemoglu et al confirm our intuition in this regard. Assuming Cournot competition between thermal generators, and assuming that these thermal generators' portfolios include renewables, they find that strategic withholding of output dulls or even fully neutralizes the merit order effect (rightward shift in the supply curve) that the empirical literature on renewables discusses. The existing literature on power pools suggests that the Cournot assumption is a reasonable approximation to competitive behaviour among generators (see, for example, Bert Willems et al, "Cournot versus supply functions: What does the data tell us?" (2009) 31:1 Energy Economics at 38–47). When all thermal generators are vested in renewables—"full diversification" – the merit order effect of renewables is fully neutralized. See Daron Acemoglu et al, *Competition in Electricity Markets With Renewable Sources* (Cambridge: MIT, 2015), online: MIT <https://asu.mit.edu/sites/default/files/documents/publications/MAIN-submit.pdf>.

particular that of Germany) to use feed-in tariffs, wherein payments to renewables are not linked to the market price for electricity. European experience of premature asset retirements and mothballing also supports the idea of straightforward stranded assets problems induced by renewables policy. The introduction of a large quantity of renewables has rendered some existing and even some brand new thermal generation facilities uneconomic.

Even if the market power effect fully offsets the merit order effect, the increased incentive to exercise market power is not a good market outcome. Scarcity pricing in a competitive market allows generators to earn quasi-rents but in a fashion consistent with allocative and dynamic efficiency. The exercise of market power, on the other hand, preserves generators' profits, but only at the expense of allocative efficiency—too little generation is supplied to the market. Further, it is likely to produce dynamic inefficiencies. The "long-run equivalent" of withholding is simply not to invest in the most frequently withheld types of generation capacities (assuming that there are non-trivial barriers to new entry in generation). These could be mid-merit generation sources, such as CCGTs.

Europe's Experience

The EU's 2008 renewable energy directive bound member states to national renewables targets in the context of an EU-wide objective of achieving 20 per cent of final energy consumption from renewable sources by 2020.[19] Generous subsidies helped countries make substantial progress towards these targets. Between 2005 and 2014, renewables' share of electricity generation grew from about 15 per cent to almost 30 per cent (at a compound annual growth rate of 7 per cent). In the five largest electricity markets in Europe, renewable share of electricity grew at 10 per cent per annum over the same period.[20] Although country-level progress varies, the EU is expected to meet the "20 per cent by 2020" target. A new target of 27 per cent of final energy consumption by 2030 has thus been set.[21]

A growing body of literature highlights two major effects from increased renewable generation on electricity producers in some countries:

1. Wholesale electricity prices are reduced (and can be more volatile); and

2. The incentives for investment in new thermal generation have been reduced, with implications for future system reliability.

In 2014, the European Commission wrote:

"Increasing amounts of electricity generated from wind and solar have also exerted downward pressure on wholesale prices particularly in regions with high shares of these renewable energy sources …"[22]

Various authors have analysed ex-post data on electricity prices and renewable capacity in several countries with significant amounts of renewable generation with similar conclusions on the direction of effect.[23] They have identified an increased correlation between the availability of wind generation and electricity prices and so confirm the primary merit order effect and that this has (other things being equal) reduced electricity prices. The studies (because of differences in methodology) are difficult to compare but the estimated effects, as measured, in some markets (where renewable penetration

19 They are also each required to have at least 10 per cent of their transport fuels come from renewable sources by 2020; National renewables targets have ranged from 10 per cent in Malta to 49 per cent in Sweden, European Commission, *Renewable Energy*, online: EC <https://ec.europa.eu/energy/en/topics/renewable-energy>. Countries also developed renewables action plans that included sectoral renewable energy targets and goals for different mixes of renewables deployed.
20 Eurostat, "Electricity generated from renewable sources", 2016, European Commission, online: EC <http://ec.europa.eu/eurostat/tgm/table.do?tab=table&plugin=1&language=en&pcode=tsdcc330>: "Electricity produced from renewable energy sources comprises the electricity generation from hydro plants (excluding pumping), wind, solar, geothermal and electricity from biomass/wastes. Gross national electricity consumption comprises the total gross national electricity generation from all fuels (including auto production), plus electricity imports, minus exports." Top 5 markets selected by total consumption of electricity.
21 European Commission, *2030 Energy Strategy*, online: EC <https://ec.europa.eu/energy/node/163>.
22 European Commission, *A policy framework for climate and energy in the period from 2020 to 2030* (2014) at p 9.
23 See Klaas Würzberg et al, "Renewable generation and electricity prices: Taking stock and new evidence for Germany and Austria", (2013) 40 Energy Economics, for a comparative survey of recent literature on merit order effects in various European electricity markets.

is high such as Spain and Germany) have been very significant.[24]

Renewable generation's rise has displaced fossil-fuelled generation. Given relatively (compared to natural gas) cheap coal prices in Europe, natural gas generation has suffered the most displacement, with coal-fired generators able to protect their position in the merit order in the short-run. Traber and Kemfert and Van den Bergh et al find that financial support for renewable generation may have also dampened EU emissions prices by reducing demand for fossil fuel generation and consequently lowered demand for emissions credits.[25] As noted, an unintended consequence is that lower emissions prices have also disproportionately benefitted coal generation over gas-fired generation in the merit order. After a long period of growth, electricity generation from natural gas peaked in 2008 and has declined since.[26]

Falling prices, resulting from renewable generation, has in some countries contributed to a decline in quasi-rents available to thermal generation. Industry association, Eurelectric, concluded that incorporating renewable energy supplies reduced the operating hours and profitability of thermal generation. It also found that scarcity pricing in the fewer remaining operating hours has, "generally not been enough to cover the costs of 'peaking' plants (such as CCGT)."[27] This results from the increased margin of supply over demand that has resulted from increased renewable energy supply and a contemporaneous decline in demand from the financial crisis and ensuing recession. Renewable energy supplies have effectively increased the share of load being supplied by notionally baseload plant which has made peak hours more competitively traded.

Fewer profitable generating hours, to which renewables (in some markets) have in part contributed, for thermal – and in particular gas generation—have predictably led to plant mothballing and closures. Caldecott and McDaniels[28] reported write-downs for natural gas power assets to six major utilities of €6 billion. IHS estimated that 21GW of natural gas fired power plants was closed between 2008 and 2014.

These developments helped inform concerns – also raised by Eurelectric—about growing long-term capacity challenges: the EU worries that the current diminished economics of thermal generation provides little indication of future capacity needs (EU 2014). Long lead times in power sector investments mean that today's depressed and uncertain market economics for thermal generation provide a significant disincentive to invest. The EU also found that price caps and other measures such as operating reserves, emergency demand response, and voltage reductions are suppressing price signals in hours of scarcity which otherwise might have signalled the need for capacity investment. Most countries face no imminent capacity crunch (Britain excluded). But the impending retirement of ageing coal and nuclear facilities could change that picture.[29]

Policy Responses: Capacity Mechanisms and Capacity Markets

The growing adequacy-related concerns discussed above have motivated increased policy-making interest in mechanisms designed to ensure adequate generation capacity. This is particularly true of the interest around "capacity mechanisms" that specifically reward generators for capacity rather than energy.

24 Hugo A. Gil et al, "Large-scale wind power integration and wholesale electricity trading benefits: estimation via an ex post approach" (2012) 41 Energy Policy at 849–859; Sensfuss et al, "Analysen zum merit-order effekt erneuerbarer energien: Update für das jahr 2010" (2011) Frauenhofer ISI, Karlsruhe, estimated an effect in the period 2006-2010 of about €6/MWh in Germany (equivalent to roughly as much as 10 per cent of the prevailing baseload price).

25 Thure Traber & Claudia Kemfert , "Impacts of the German Support for Renewable Energy on Electricity Prices, Emissions and Firms" (2009) 30:3 The Energy Journal at 155–178; Kenneth Van den Bergh et al, "Impact of renewables deployment on the CO_2 price and the CO_2 emissions in the European electricity sector" (2013) 63 Energy Policy at 1021-1031.

26 Eurostat, *Gross electricity generation by fuel, GWh, EU-28, 1990-2013,* online: EC <http://ec.europa.eu/eurostat/statistics-explained/index.php/File:Gross_electricity_generation_by_fuel,_GWh,_EU-28,_1990-2013.png>.

27 Eurelectric, "RES Integration and Market Design: Are Capacity Remunerations Mechanisms Needed to Ensure Adequacy" (2011) at p 4.

28 Ben Caldecott & Jeremy McDaniels, "Stranded generation assets: Implications for European capacity mechanisms, energy markets and climate policy" (2014) Smith School of Enterprise and the Environment Working Paper, online: <http://www.smithschool.ox.ac.uk/research-programmes/stranded-assets/Stranded%20Generation%20Assets%20-%20Working%20Paper%20-%20Final%20Version.pdf>.

29 Many nuclear plant in Europe will be over 30 years old by 2020, while some countries such as the Netherlands and the UK have issued explicit coal retirement mandates.

Such mechanisms were originally developed in several U.S. and European electricity markets as a response to the "missing money" problem.[30] The advent of a large amount of subsidized and highly intermittent generation capacity has been one important contributory factor to the sustained interest and innovation in capacity mechanisms in Europe in recent years.[31] In effect, capacity mechanisms reflect the belief that electricity market prices cannot provide thermal generation investors with the assurance of higher prices for future capacity to offset renewables-induced lower utilization and higher uncertainty.

The European Commission's recent study of capacity mechanisms—impelled by the increased salience of these mechanisms[32]—identifies two broad types of capacity mechanisms: (a) targeted and (b) market-wide. In the former case, system administrators determine how much capacity is required over and above what the market would provide. System operators then either provide payments (at an administratively determined price) for specific types of capacity, or hold tenders to elicit the required capacity. Alternatively, system operators can procure capacity through a centralized auction, or they can require electricity suppliers or retailers to contract for top-up capacity with generators. The system operator can also construct estimates of how much capacity is required on a going-forward basis and pay would-be capacity providers on the basis of its estimates of the cost of providing new capacity. These various mechanisms differ substantially in terms of the degree to which they represent a genuine "market" for capacity—indeed some are simply "command and control" processes.

The experience of the United Kingdom is perhaps the most interesting development in European capacity mechanisms and there are some analogies to the situation in Alberta. The UK, perhaps unlike mainland Europe, needs new capacity and it needs it in the short to medium term. It committed to completely phase out coal generation by 2025. Until recently coal was responsible for about 30 per cent of UK electricity production. Some plant are retiring over the next few years. For the remaining plant, this commitment was made contingent on new gas-fired power plants being developed. However, the electricity energy-only market and other short term measures used by the system operator for system reliability are not providing sufficient incentives to invest in new large-scale capacity.

The UK has conducted two capacity auctions to date (in 2014 and 2015) for capacity in 2018 and 2019 respectively with longer term contracts being available for new generation. Both auctions, however, cleared at prices well below what is considered to be necessary to build a new CCGT. In fact only two CCGTs, one of which was already in development, received long-term capacity contracts.[33] The only other new plants have been diesel-fired peaking plants. This was not necessarily the outcome intended when the auctions were conceived.

This outcome reflects a balance the Government struck between the amount of capacity to procure and prevailing concerns about the cost of electricity to consumers. It also highlights

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30 The economic literature identifies several other potential solutions to the inherent scarcity pricing conundrum of EOMs. Among these are (a) relaxing or abolishing administratively imposed price caps, (b) allowing prices to rise to the price cap level whenever out-of-market resources are called upon to generate, (c) enhancing demand-side response mechanisms in the market. Another approach is the development of a market for operating reserves.

31 European Commission, *Interim Report on the Sector Inquiry on Capacity Mechanisms: Commission Staff Working Document*, (Brussels: 13 April, 2016), at 4, 12, 30, and nn 23, 36. These excerpts highlight the belief that renewables worsen the missing money problem.

32 Capacity mechanisms raise concerns about so-called "State Aid", which was the proximate reason for the Commission's investigation. However, the Commission Staff Working Document, *supra* note 31, discusses the deep-seated economic causes at 4:

> "The large-scale roll-out of renewables combined with the overall decline in demand and the decreasing cost of fossil fuels have curbed the profitability of conventional generators and reduced incentives to maintain existing power plants or invest in new ones. In many Member States, these developments have been accompanied by increased concerns about security of supply. Member States are concerned that the electricity market will not produce the investment signals needed to ensure an electricity generation mix that is able to meet demand at all times…Some Member States have reacted by taking measures designed to support investment in the additional capacity that they deem necessary to ensure an acceptable level of security of supply. These capacity mechanisms pay providers of existing and/or new capacity for making it available."

33 ICIS, "UK CCGT developers keep faith with capacity market" (2016), online: ICIS <http://www.icis.com/resources/news/2016/04/22/9990602/uk-ccgt-developers-keep-faith-with-capacity-market/>.

the fact that a capacity market brings another set of non-market interventions which may not, without significant design consideration, deliver new capacity as required at least cost to consumers. If the introduction of a large quantity of renewables to Alberta's market has the same effect on thermal generators' investment incentives, instituting capacity auctions or capacity markets does not represent an easy-to-design "fix".

Does European experience hold lessons for Alberta?

If there are lessons to be drawn from Europe's experience with renewables, what are those lessons and how might they direct policy-makers in the development of Alberta's electricity system?

Economists generally seem to accept that the positive supply shock from renewables worsens the "missing money problem". European experience indeed shows that there are lower prices and growing concerns about how to effectively ensure long-term adequacy and reliability. These concerns are focused on the incentives of thermal generators, perhaps particularly natural gas fired plants, to add capacity over a multi-year period. Generators in Europe have responded to a renewables-assisted supply shock (creating temporary over-supply) with rationalization of gas facilities and gas investments. Leaving aside the policy preference for gas over coal, this short-run rationalization is not creating an adequacy problem in the short run. Europe's concern is that investors might, however, continue to rationalize for as long as they think prices will remain low.

As the European Commission's recent Staff Working Document points out, it is difficult to calibrate the timing of capacity investments with actual surpluses or shortages in the energy markets. Generators might not respond to shortages until the shortage becomes apparent, and critically, until it is reflected in actual energy market prices.[34] Low prices, today, resulting from renewables might, therefore, embed expectations that prices will be lower for longer (than rationally might be expected). This may dampen thermal generation investment intentions, particularly if investors are already scarred by their experience of the regime changes that renewables have wrought. Renewables also add incremental uncertainty to the investment decision-making process, particularly if renewables targets and procurement mechanisms are continually revised. These effects are all the more pronounced because electricity forward markets are insufficiently liquid to handle contracts for a significant volume of delivery over the long-term.

There are straightforward differences between Alberta and Europe: a preference for coal rather than gas investments is a problem that will not arise in Alberta. But there is no denying that renewables will make investment in thermal resources less attractive simply because of lower and less certain operating hours for thermal generators. Timely and adequate investment in these facilities will depend on investors' confidence that prices will ultimately rise, and crucially that they will be allowed to rise as necessary. Europe's renewables push was substantially crafted without regard to incentives in the restructured electricity market. Consequently, European countries have had to adapt and develop or enhance institutions such as capacity markets in an effort to cope with the aftermath. The results of this continuing institutional improvisation are unclear. Alberta has an opportunity, however, to consider the role of policy factors that might facilitate investment within the context of the energy-only market. We offer three considerations below, based on Europe's experience and the economic literature, which might be relevant to Alberta's transition. These considerations are crafted with the energy-only market in mind. There are, of course, other policy responses such

34 The European Commission Staff's Working Document states, *supra* note 31 at 25, that expectations about future prices are more important to investment decisions than current prices. In many other commodity markets, well-developed futures markets offer an offset against the uncertainty inherent in long-term pricing expectations. This is perhaps less true for electricity. The Commission Staff also notes (n 37, citing De Vries) that given uncertainty about future prices, investment decisions could be delayed so as to result in significant periods of actual shortages. The EC's document thus points to two distinct but inter-related possibilities. First, there is the problem that adjusting from one equilibrium to another is not frictionless. Unlike in other long-cycle commodity industries—e.g., oil sands—there is a compelling policy interest in avoiding a disequilibrium that leads to actual shortages of electricity. Thus at a minimum policies that contribute to uncertainty and thus create frictions in the adjustment process should be avoided. Second, there is the problem that investment levels in equilibrium might be inefficient. Even if regulators avoid actual physical scarcity, can they do so in the efficient (least-cost) fashion?

as capacity markets and their design, but these are farther-reaching than the considerations we detail below.

Consideration 1: Coordination between Quantity Commitments for Renewables and Coal

Europe's lack of extensive coordination in matching renewables introduction with the retirement of some conventional base-load partly accounts for the reduction in available quasi-rents and reduced investment incentives.

Alberta's proposed retirement of coal plant and its replacement (in part) through renewable generation might benefit from careful coordination. Alberta might specify a schedule that lays out what quantity of renewables will be procured and when. The more stable are investors' expectations about the quantity and timing of renewables introduction, the easier it is to predict future prices and adjust investment decisions accordingly. Obviously such commitments would need to be credible in order to be effective. The temptation to frequently revise renewables targets would need to be resisted, for instance.[35]

Providing certainty and commitment as to the schedule of base-load retirements improves, at least marginally, market participants' ability to anticipate future prices and capacity availability. The commitment to retire coal capacity expeditiously, but in an orderly fashion, will offset some of the possible supply shock effects of introducing renewables to Alberta's market. In practical terms, given what has already been proposed, this means sticking to the 2030 sunset date for coal. An unpredictable and chaotic process would harm investor confidence—this is perhaps the danger that Alberta faces if investors perceive the ongoing unwinding of PPAs as chaotic and subject to political uncertainty.[36] A structured transition ought to be feasible through the periodic renewables auction process as envisaged by the AESO.

Consideration 2: Rethink Price Caps

If investment incentives do emerge as an issue, Alberta might consider revising the current price cap towards a level more consistent with estimates of the Value of Lost Load (VOLL). With potentially fewer hours of scarcity resulting from increased renewables generation, it will be more important to allow for the market price to effectively price that scarcity. While prices will only ever hit such levels in a few hours every few years, the profits from such scarcity hours could be very important in sustaining peaking capacity that is required in scarcity hours, while increasing quasi-rents for low and intermediate-cost capacity.

Alberta could also allow demand response to participate in any future capacity mechanisms as the U.K. has, but demand response's ability to be an effective participant depends on technological progress substantially determined outside Alberta's control. Also there is the risk that demand response that does not have stringent performance requirements attached to it will do little for reliability, while damping price signals for thermal generation.

Consideration 3: Role of Market Prices in the Renewables Auction

The design of any renewables auction may also need to consider whether payments to renewables providers should or should not be linked to the market price. There is increased pressure in Europe to expose renewable generation to market forces in order to reduce the cost of subsidies and transition those technologies ultimately into the market. Recent literature suggests the possibility, however, that during hours when renewables are generating, diversified generators' incentives to exercise market power increase. This incentive to withhold arises because of diversified generators' ability to earn higher margins on their infra-marginal renewables capacity when they engage in withholding.

While this has the effect of restoring prices and offsetting the merit order effect, it does so inefficiently, through the exercise of market power. If the magnitude of this inefficiency is large relative to the benefits from tying renewables prices to market prices, then the

35 This may suggest that the renewables process be governed by an agency that is not incentivised one way or another by achieving higher renewables penetration.

36 The Alberta AESO's 2016 Long-Term Outlook does provide details of an assumed retirement schedule for coal and assumptions about wind capacity additions in the future. AESO, *AESO Long-Term Outlook* (2016), online: AESO <https://www.aeso.ca/grid/forecasting/>.

auction design might be modified such that bidders bid on their costs and not the difference between their costs and their expectation of future market prices. In any case, any given market participant's expectation of future market prices will depend on the aggregate quantity of renewables that it expects to be supplied in future years, and on the strategic response of owners of thermal generation to the introduction of renewables. Needless to say this is a tough calculation to make, even if commitment to providing quantity certainty with respect to renewables may make it slightly easier.[37] Additionally, persistently low price expectations would mean high subsidy bids and thus defeat any benefit arising from the linkage between subsidies claimed and market prices.

Alberta may consider designs such as the UK in which an auction is held to determine the price support that will be guaranteed to winning producers over a fixed time period. It is structured, however, as a fixed-for-float swap. As the market price rises, the level of subsidy reduces leaving aggregate support to the producer unchanged. This appears to be the option preferred by the AESO.

Finally, recent political developments in the United States cast some doubt on the ability of Canadian Federal and Provincial governments to stick to currently announced climate change mitigation initiatives. This makes the structured approach, outlined above, more relevant to the design process. ■

[37] Additionally, persistently low price expectations would mean high subsidy bids and thus defeat any benefit to the government arising from the linkage between subsidies claimed and market prices.

COMPETITION IN ELECTRICITY TRANSMISSION: TWO CANADIAN EXPERIMENTS

*Ian Mondrow**

Introduction

Electricity transmission is a natural monopoly.

It is expensive to build. It requires highly specialized knowledge to plan and integrate with existing electrical systems. It has a long, linear footprint which takes a long time to consult about, assemble and environmentally evaluate. It gets built in relatively large chunks. It requires large amounts of capital locked up for long periods of time.

In a very particular set of circumstances, a "merchant" electricity transmission line (one supported entirely by revenues from providing competitive services directly to customers) is possible. Indeed, one has been built to connect wind generators in western Montana with Alberta's unrequited domestic electricity demand.[1] Subject to these highly circumstance specific exceptions to the rule, electricity transmission does not get built without investment protection through an effective long-term monopoly franchise.

Nonetheless, in two Canadian provinces – Ontario and Alberta – "transmission competition" is no longer an "oxymoron".[2] It is no co-incidence that the two Canadian jurisdictions with some aspirations to competitive electricity markets have found a way to inject some of the rigours of competition into the development of new electricity transmission infrastructure.

While we will not see price wars between parallel transmission line operators in Ontario, or transmission customer loyalty programs in Alberta, in each of these jurisdictions regulators and government policymakers have developed a way to supplement traditional economic monopoly regulation with some competition. The objectives in both cases are to deliver cost savings and bring a degree of technical, financial and/or project execution innovation to the business of developing electricity transmission.

Economic Regulation: Strengths and Weaknesses

"Economic regulation" commonly refers to setting "tariffs" (rates and conditions of service) for use of regulated infrastructure. It is a price control mechanism applied in circumstances of a "natural monopoly" to protect both consumers (in place of market discipline on pricing and service quality) and infrastructure investors (providing some assurance of return of and on the investment).

The point of departure for economic regulation in electricity is "cost of service". Under traditional cost of service regulation, the regulator will engage in a process (typically a

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1 The Montana-Alberta Tie Line (MATL) acquired in 2011 by Enbridge from Tonbridge went into service in September, 2013.

2 The author is referring to Scott Hempling's previous article, as used by Mr. Hempling for the title of his August, 2016 monthly essay describing the U.S. Federal Energy Regulatory Commission's removal of the "right of first refusal" provisions of American Regional Transmission Organization (RTO) contracts and associated legislative frameworks for development of new electricity transmission. Now published, Scott Hempling, "Transmission Competition in the United States: The New Reality" (2016) 4:3 Energy Regulation Quarterly 49.

hearing with discoveries and oral examination) to test utility reported costs and make a finding on a reasonable level of cost to be incurred by the utility to provide utility service. The reasonable "cost of service" so determined converts into a "revenue requirement" for the utility. The revenue requirement is divided amongst billing determinants (number of customers and forecast customer volumes) to determine rates.

This has been a fairly stable and predictable way to determine utility rates that will allow the regulated utility to recover its costs (including its cost of capital). This stability and predictability is good for both utility investors and utility ratepayers. It is an effective way to control utility costs, allowing only costs determined to be "prudent" to be recovered.

However, prudency is an after the fact determination, rendering disallowance practically difficult and an exception rather than common practice. Subject to egregious overruns, cost risks generally lie with ratepayers. Further, the default of allowing recovery of prudent costs provides limited incentive to *reduce* costs through efficiency and innovation.

Regulators have for some years attempted to address these weaknesses of traditional cost of service regulation by developing incentive regulatory models. Such models assume productivity gains in setting rates, or incent innovation and efficiency by allowing utility shareholders to retain a portion of any resulting cost savings for a period of time. While these mechanisms seem to have had some success in improving the outcomes of economic regulation, the focus has generally remained on the subject utility, comparing its forecast or current costs against its historical costs.[3]

Drivers for Change: Cost Reduction, Innovation and Capital Attraction

While downward pressure on costs and encouragement of innovation are outcomes not intrinsic to traditional "cost of service" regulation, they are outcomes of proper competition. The two regulatory innovations examined here both had these outcomes as objectives.

An additional express objective of both experiments was attracting new investment capital. Developing major infrastructure during periods of strong economic growth (such as when the bulk of our electricity system was built) is easier than doing so during less stable economic times (like now). Compared to the post war era of economic growth, governments have less available capital today.

In addition, public awareness of, and concern for, energy costs is heightened today relative to the past. It is said that consumers are more educated and aware in our current age of immediate access to limitless information. At the same time (and perhaps in the result), polling indicates that consumers are less trusting of government and its institutions today than they have been in the past, and that this is particularly apparent when it comes to electricity. The combination of heightened public awareness and knowledge with decreased consumer trust results in more political divisiveness, which in turn incents governments to focus on avoidance of cost overruns and other unpleasant surprises in the building of new public infrastructure like electricity transmission.

Pressures to contain costs, reduce costs and transfer risk away from the public when developing new electricity transmission have prompted regulatory innovations in several jurisdictions.

In the U.K., the Office of Gas and Electricity Markets (Ofgem) has developed an incentive and innovation regulatory model which includes involving 3rd parties in design, build, operation and ownership of large, "separable enhancement" electricity transmission projects. One of the express objectives of this policy is to deliver technology, delivery solution, and financing innovations.

In the United States, the Federal Regulatory Energy Commission (FERC) has done work on pre-designating interstate transmission corridors, developing ratemaking tools to provide incentives for large infrastructure investments, and dismantling "right of first refusal" (ROFR) mechanisms embedded in regional transmission organization (RTO) contracts and related regulatory instruments.[4]

The Public Utility Commission of Texas

3 Though productivity expectations often are derived from external benchmarks or cost trends, but it is hard to find strong comparators.
4 *Supra* note 2 at p 49.

identified and designated Competitive Renewable Energy Zones (CREZ) and a number of defined transmission projects to be built therein, and through new regulatory processes invited and approved proponents to develop, construct and operate each of these projects.

In Canada, the Ontario Energy Board (OEB) has developed a competitive regulatory process, and the Alberta legislature has introduced a "regulation by contract" mechanism.

A Competitive Regulatory Process: The Ontario East-West Tie Line

In August of 2010, the OEB issued its *Framework for Transmission Project Development Plans*.[5] The overall objective of this policy is to facilitate "timely and cost effective development of major transmission facilities".

With the passage of Ontario's *Green Energy and Green Economy Act, 2009*[6] the Ontario energy regulator expected a rush on development of distributed renewable generation, all of which would need to be grid connected. The OEB foresaw need for a significant investment in transmission infrastructure in order to accommodate all of the anticipated growth in renewable generation.

The Board's policy expressly intends to "encourage new entrants to transmission in Ontario bringing additional resources for project development". The policy also indicates an intent to "support competition in transmission in Ontario to drive economic efficiency for the benefit of ratepayers". The Board stated its belief that "economic efficiency will be best pursued by introducing competition in transmission service to the extent possible within the current regulatory and market system."

The OEB does not have jurisdiction to procure transmission services, or enter into contracts with transmitters to build or operate transmission infrastructure. It does, however, have the jurisdiction to determine regulated utility cost recovery. The Board developed a policy intended to provide greater certainty for cost recovery of electricity transmission development work, and to encourage participation by new entrants in a competitive development designation process.

Ontario's electricity grid planner and operator – the (now) Independent Electricity System Operator (IESO) – would identify a required transmission line. Once a required line was identified, the Board would issue an invitation for proposals for development, construction and operation of the line. The notice would convene a process to "designate" a proponent to develop (i.e. plan) the project.

The implication of designation was that the proponent would recover its development costs, up to the development budget approved in the designation proceeding, regardless of whether the line proceeded (unless it was the proponent's fault that the line did not proceed). This assurance would allow new entrants, without an existing customer base in the province, to undertake development activities with the same degree of assurance that the incumbent transmitter has that development costs would be recovered. In the East-West Tie Line process to which this new framework was applied, development costs were forecast in the range of \$18 million to \$24 million; a non-trivial investment for which some comfort of eventual recovery is a material incentive.

The OEB designated project development proponent would proceed with development work, and would be expected (unless the initial IESO "need" determination were revisited and reversed) to bring a leave to construct (LTC) application. The LTC process would result in a final finding on need (relying primarily on the IESO's determination thereon), confirm the "necessity and public convenience" of the project as proposed, and approve a construction cost forecast which in turn provides the basis for eventual recovery of construction costs from ratepayers.

The details of the policy were also designed with competitive forces in mind.

Only the designated transmitter would be able to recover the costs of preparing the application for designation. During the East-West Tie process, competing proponents reported application costs in the \$1 -\$2 million range, indicating that even the pre-development

5 Ontario Energy Board, *Framework for Transmission Project Development Plans*, EB-2010-0059 [*OEB Framework*].
6 *Green Energy and Green Economy Act, 2009,* SO 2009, c 12.

application preparation work entails a material contingent investment. As the OEB noted in its policy, the "at risk" nature of the up-front costs of preparing the designation application "is comparable to the more usual business model in which proponents prepare proposals or bids at their own cost and own risk." It is noteworthy that most of the proponents, including the successful applicant, offered to absorb their own application costs, if designated; another indicator of competition and innovation pressures at work.

The OEB also signalled in its policy that "financial models [for construction/operation of the line] that do not put the risk on ratepayers or increase rates would be of interest to the Board".[7] The applicants competing for the East-West Tie designation expressly proposed various risk sharing mechanisms in their applications.

Given that the choice of the successful development proponent was premised on comparing development budgets (among other factors), recovery of un-forecasted development costs would likely present a relatively high justification hurdle, placing the risk of cost overruns on the developer.

The new OEB competitive development designation process has been used once to date.

In November, 2010, the Ontario government published its first Long Term Energy Plan (2010 LTEP).[8] The 2010 LTEP identified 5 priority transmission projects. Hydro one was already busy connecting renewable generation, including through the identified projects, and was highly debt leveraged with limited access to additional equity capital.

One among the 5 2010 LTEP priority transmission projects was the East-West Tie. The East-West Tie would be a transmission line running between Thunder Bay and Wawa, reinforcing an existing connection between Ontario's eastern and western transmission systems.

The provincial government's earlier shut down of Ontario's coal fired power plants took a large chunk of generation out of the west part of Ontario's system, which resulted in a concern that more transmission capacity could be required to convey electricity from the east and maintain reliability standards for the existing transmission connection between the east and west systems. There were also significant north-western Ontario mining prospects, development of which would require significant incremental power.

In March of 2011, Ontario's Minister of Energy wrote to the OEB, suggesting that the Board engage its previously developed transmission development designation policy to "select the most qualified and cost-effective transmission company to develop the East-West Tie".[9] The Minister's letter specifically noted as strengths of the anticipated transmission development designation process the encouragement of new entrants, in order to bring to Ontario additional resources for project development. The Minister further noted the value of competition in transmission development to drive economic efficiency for the benefit of ratepayers.

The OEB initiated the competitive East-West Tie transmission development designation proceeding by notice dated February 2, 2012. Ultimately 6 well qualified applicants responded to that notice. Several thousand pages of evidence were filed laying out six highly developed East-West Tie development plans. There was a detailed interrogatory process, and two rounds of argument.

Following all of that, by decision dated August 7, 2013[10], Upper Canada Transmission Inc. (UCT) was designated to develop the East-West Tie line.[11] UCT is a partnership of NextEra Energy Canada, Enbridge Inc. and Borealis Infrastructure Management, three highly successful and respected North American energy sector organizations. UCT's application

7 *OEB Framework*, *supra* note 5 at p 14.
8 Government of Ontario, *Ontario's Long Term Energy Plan: Building Our Clean Energy Future* (Toronto: Government of Ontario, November 2010).
9 Ontario, Ministry of Energy, "Minister's letter regarding the East-West Tie" (Toronto: Ministry of Energy, 29 March 2011).
10 *East-West Tie Line Designation Phase 2 Decision and Order* (7 August 2013), EB-2011-0140, online: OEB < http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2011-0140/Dec_Order_Phase2_East-WestTie_20130807.pdf>.
11 The writer acted as legal counsel to UCT during Phases 1 and 2 of the designation proceeding, though not subsequently.

presented; i) a competitive development cost; ii) the lowest forecast construction cost (for a double circuit proposal); iii) a competitive development schedule; iv) strong partner credentials, project experience and track records; and v) an innovative tower design proposal that, if it works, could save ratepayers an additional $30 million in construction costs.

The OEB's designation decision methodically considered and applied applicant rankings on 10 identified criteria; i) organization; ii) plan for First Nations and Métis *participation*; iii) technical capability; iv) financial capability; v) financial capacity; vi) proposed design; vii) schedule for the development and construction phases; viii) cost for development, construction, operation and maintenance phases; ix) plan for landowner, municipal and community consultation; and x) First Nations and Métis consultation.

Under discussion of the "proposed design" criterion, the OEB stated:

> "The applicants were also required to highlight the strengths of their plan in terms of innovation, reduction of ratepayer risk, lower cost, local benefits and enhanced grid reliability."[12]

Under discussion of the "cost" criterion, in response to comments from an experienced OEB intervenor regarding the basis upon which the Board can make a cost recovery decision, the Board noted:

> "By designating one of the applicants, the Board will be approving the development costs, up to the budgeted amount, for recovery. The School Energy Coalition submitted that there is insufficient information for the Board to determine that the development costs are just and reasonable. The Board does not agree. The Board has had the benefit of six competitive proposals to undertake development work. In the Board's opinion, the competitive process drives the applicants to be efficient and diligent in the preparation of their proposals. With the exception of Iccon/TPT, the development cost proposals ranged from $18.2 million to $24.0 million which is relatively narrow given the overall size of the project. Therefore, the Board finds that the development costs for the designated transmitter are reasonable, and will be recoverable subject to certain conditions."[13]

These two passages underscore the shift in regulatory principles entailed in adoption by the OEB of a competitive regulatory process for transmission development designation. The first of these passages highlights the hoped for competitive incentive for innovation and optimized risk allocation. The second of these passages explains displacement of the conventional regulatory scrutiny of the subject utility's own costs with deference to a cost discipline afforded by a competitive process. Rather than concerning itself with line by line utility cost review and justification, the regulator relied on competition to produce a discipline supporting a finding that the resulting cost was, essentially by definition, just and reasonable.

The East-West Tie project is currently delayed, though not at the instance of the successful proponent. The Ontario IESO has updated its need assessment, and deferred the recommended in-service date.

The delay prompted an application from UCT for an upwards adjustment of its development budget. Instructively, the OEB rejected the applied for adjustment[14], finding that the additional costs put forward by UCT as costs associated with an extended development period were not "akin to the Board-Approved costs in such a way that would lead to acceptance of them without further scrutiny of the prudence and reasonableness of these

12 *Supra* note 10 at p 23.
13 *Ibid* at p 30.
14 *Upper Canada Transmission Inc: Application for Approval of Schedule and Costs related to the Development of the East-West Tie Transmission Line* (19 November 2015) EB-2015-0216, online: OEB: < http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/505980/view/dec_order_east%20west%20tie_20151119.PDF>.
15 *Ibid* at p 8.

costs". The following passages from the OEB's decision merit attention[15]:

> "The OEB's process of establishing Decision Criteria in Phase One of the East-West Tie process and then undertaking a comparative analysis of submitted proposals by the applicants in Phase Two formed a comprehensive competitive process. The OEB relied on the business interests of those submitting proposals to determine the reasonableness of the cost levels. The anticipated costs that UCT has submitted are not defined within the same development cost elements as the original costs, nor are they subject to any competitive forces. In the OEB's view, prudence has not been determined in either the nature or the quantum of the costs.
>
> At the time it applied for designation, UCT was aware of the limitations of the approval granted for recovery of development costs. The OEB, in its Phase 1 Decision and Order, stated that transmitters seeking designation should be aware that development costs in excess of budgeted, Board-Approved costs would not necessarily be recovered from ratepayers and would be subject to a prudence review, which will include consideration of the reasons for the overages.
>
> The OEB does not accept that development costs not anticipated as part of the original project premise are automatically afforded the same assurance of recovery as the originally budgeted development costs, absent any examination of the reasonableness of the costs and an <u>evaluation of the expected assumption of normal business risks in determining what should be recovered from ratepayers</u>." [Emphasis added.]

To date, UCT has been held to its competitive development budget, which formed part of the basis for designation of UCT as the developer for the project. That is, the risk allocation underlying the process has, to date, been enforced.

Work on the project has slowed, but is ongoing, and we may one day see a leave to construct application for this line, and the implications of UCT's development designation stage least cost construction forecast for the utility rate base ultimately allowed.

Regulation by Contract: The Fort McMurray Transmission Project

In Alberta's case the experiment with injecting competitive forces into electricity transmission procurement was that of the legislature, not the regulator. In December, 2008, the Alberta government published a provincial energy strategy. That strategy included substantial upgrades to the transmission system, in order to: reliably serve current and forecast demand; reduce congestion; enable and support development of new generation; reduce line losses from overload; introduce newer sources of power (renewable, low emission, and cleaner fossil fuel production); increase intertie capacity; increase efficiency; maintain a robust electricity transmission infrastructure; and address the government's goals of increasing competition in, and attracting investment in, critical transmission infrastructure.

Further to the province's energy strategy, in November, 2009 Alberta passed legislation to address approvals for "Critical Transmission Infrastructure" (CTI). The legislation provided that CTI would be as designated by the Minister of Energy. Once a transmission project was designated as CTI, there were two paths for designation of a proponent to develop, construct and operate it; i) designation of a proponent by the Minister; and ii) determination of a proponent through a competitive bidding process run by the Alberta Electricity System Operator (AESO).

Under the pre-existing Alberta electricity planning model, the AESO assigns authority to an incumbent transmitter to apply to the Alberta Utilities Commission (AUC) for approval to construct a transmission line, and ultimately to set the transmission rates for the facilities. Under the new, competitive, model, the AESO holds a bidding process to choose the transmission developer, and the successful bidder is assigned the authority to apply for approval to construct the transmission line. Further, the rates for services from the new facilities are to be set based on the contract resulting from the AESO's bidding process. Under the new, competitive model the AUC's job in determining just and reasonable transmission service rates is to approve an AESO run bidding process that is properly competitive. The legislative policy is that the transmission costs (rates) resulting from a properly competitive bidding process would be "just and reasonable".

The Alberta government designated a CTI line to run from Edmonton to Fort McMurray to which the new AUC approved AESO competitive process would be applied. Following passage of the Alberta legislation, the AESO embarked on a consultation process to develop the competitive procurement model to be applied to the Fort McMurray line, and future competitive CTI procurements.

The AESO's materials describe some of the key objectives and principles of its intended process as follows:[16]

> "These objectives and principles are designed to meet the goal of the Process for CTI to create a fair, transparent and openly competitive opportunity for incumbent and new entities to develop, own and operate CTI....
>
> - the competitive model must result in the minimization of life-cycle costs through the use of competitive pricing,
> - the competitive model must create opportunity for maximum innovation throughout the life cycle of the CTI facility,
> - the competitive model must create opportunity for new market entry,
> - the competitive model must allocate risk to most efficiently and effectively reduce costs and mitigate risk..."

After several rounds of consultation and iteration, the AESO applied to the AUC in September, 2011 for approval of its proposed competitive process.

The AUC's first task, given the various positions being advanced before it, was to clarify its interpretation and intended application of the new legislative scheme for competitive transmission procurement and rate setting. The AESO's proposed process included the possibility of bilateral negotiations between it and the successful bidder, in finalizing the contract the financial terms of which would ultimately be accepted by the AUC through a rate order. The Commission had concerns that, in the result, final rates would be determined not by a transparent competitive process, but through bilateral discussions between the AESO and the winning bidder. In a "Part A" decision in the matter dated February 27, 2012[17], the Commission found that in order for the rates resulting from the AESO's process to be accepted as just and reasonable, the AUC must be satisfied that the form and content of the process will yield a truly competitively determined result. Only then could the traditional regulatory determination of "prudence" of specific costs be replaced by a deeming of the resulting customer rates as "just and reasonable" and in the public interest. The commission found that bilateral negotiations with the successful bidder would *not* satisfy the requirements of the scheme that the prices be the result of a robust and transparently competitive process.

The AUC applied the same principles to in-term contract changes. The Commission found that unless such changes themselves resulted from a robust and transparent competitive process, they would require commission approval in the traditional fashion.

The Commission also found that since the competitive process would ultimately yield a fixed revenue contract for construction and operation of the transmission line, it would be important for the contract to include end of term asset condition standards, supporting inspection rights, and effective reward/penalty

16 AESO, *Competitive Process for Critical Transmission Infrastructure*, Recommendation Paper (Calgary: AESO, 1 June 2011) at section 6.1.

17 *Alberta Electric System Operator Competitive Process Pursuant to Section 24.2(2) of the Transmission Regulation, Part A: Statutory Interpretation* (27 February 2012), 2012-059, online: AUC <http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-059.pdf>.

provisions to ensure appropriate reinvestment in, rather than detrimental harvesting of, the assets.

Finally, the commission found that, once the initial term expired, a new competitive process would be required to establish the entity eligible to apply for permission for ongoing facility operation. Failing such a process, traditional commission approval of the operator and its costs would be required.

The AUC's statutory interpretation decision resulted in the AESO having to go away and adjust its intended process, and file additional evidence outlining revisions to its process in order to standardize the bidding framework to ensure that all contract adjustment mechanisms were determined *prior to* bids being submitted.

Following revisions to the AESO's filing to address the Commission's interpretive directions, the AUC proceeded with its hearing. The AUC ultimately approved a competitive transmission procurement framework by decision dated February 14, 2013.[18]

In the interim, legislative amendment made the Fort McMurray – Edmonton Transmission line the only line currently legislatively subject to this new competitive process (though there is some anticipation of future return to this model).

The AESO has proceeded first with Fort McMurray West, a 500 km portion of the full Edmonton to Fort McMurray line. Expressions of Interest were requested by the AESO in May of 2013. The AESO's website notes that "the competition attracted companies from across the globe." A Request for Qualifications then ran from July to December of 2013. The AESO provided draft project agreements to allow bidders an early look at the proposed proponent/ratepayer risk allocation. The AESO notes that "[f]ive world-class teams that met the AESO's criteria were short-listed and were invited to submit technical proposals as well as a price..." The RFP ran during 2014, and entailed; i) technical submissions from bidders; ii) multiple rounds of confidential collaborative meetings (which had both a technical and commercial focus) with each bidder; and iii) issuance of final versions of the project agreements. The entire process was subject to a fairness advisor review and public issuance of a fairness opinion.

In the result, Alberta PowerLine Limited Partnership – a partnership between Alberta-based Canadian Utilities Limited (an ATCO company) and United States-based Quanta Capital Solutions, Inc. - was awarded the contract for the Fort McMurray West 500 kV Transmission Project in December of 2014. Alberta PowerLine filed an application for AUC approval of the proposed Fort McMurray West facilities in December, 2015, contemplating a 2019 in service date. At the time of writing an oral hearing is scheduled to commence shortly.

According to the AESO, relative to an early estimate of costs for the project, "[t]he [Fort McMurray West] competition cost savings for Alberta ratepayers is conservatively estimated to be over $400 million."

Success?

Have the two Canadian experiments with "competitive transmission procurement" yielded the hoped for results?

Ontario's experiment in a regulatory competition for designation to develop major electricity transmission infrastructure has; i) enticed a new entrant; ii) resulted in a fixed development cost within a range of costs defined by the competition; and iii) promised the lowest construction costs as among the 6 respondents and well below the high level costing by the province's incumbent transmitter prior to the project being designated for the new competitive development process. An early request for a development cost increase was denied, subject to future re-consideration but with some indication development cost increases may be at the risk of the designated developer rather than ratepayers. Should the project proceed, and a leave to construct be brought by UCT, the development and construction cost discipline and innovation incentive promised by the competitive development designation process will be tested in what will hopefully be a full and transparent regulatory process.

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18 *Alberta Electric System Operator Competitive Process Pursuant to Section 24.2(2) of the Transmission Regulation, Part B: Final Determination* (14 February 2013) 2013-044, online: AUC <http://www.auc.ab.ca/applications/decisions/Decisions/2013/2013-044.pdf>.

Alberta's regulation by competitive contract experiment has yielded a reported $400 million saving for ratepayers, relative to the AESO's early estimate of Fort McMurray West lifecycle costs. The Alberta experiment is bolder than Ontario's in that it applies a new competitive model and the resulting long-term contract to the entire decade's long project lifecycle, including construction and operation costs, risk allocation, and resulting rates. There is, however, concern whether there will be sufficient transparency on actual construction and operating costs to validate the claimed savings. Further, while the competitive contracting process did attract some fresh investment capital in the form of Quanta Capital Solutions, Inc., the operational partner in the successful bidder - ATCO - is one of the province's incumbent transmitters.

While the Ontario East-West Tie Line appears to be proceeding, slowly, and the Alberta Fort McMurray West project will be proceeding to hearing imminently, neither Ontario nor Alberta have expanded their respective competitive transmission procurement experiments beyond these initial forays. If these two experiments eventually come to successful fruition, perhaps "competitive transmission" will get another chance in Canada. ■

A REQUIEM FOR THE PRESUMPTION OF PRUDENCE AFTER *OPG* AND *ATCO*

*Venessa Korzan and Moin A. Yahya**

I. Introduction

There was once a popular view that forecasted costs should be reviewed by the various utility regulatory bodies, such as the Alberta Utilities Commission (previously called "EUB") or the Ontario Energy Board, under a forward looking 'onus of proof on the utility' reasonableness test, while already incurred costs should be reviewed under a presumption of prudence test.[1] This view is no longer valid after the Supreme Court's companion-cases of *ATCO Gas and Pipelines v Alberta (Utilities Commission)* [*ATCO*],[2] and *Ontario (Energy Board) v Ontario Power Generation Inc* [*OPG*].[3] The Supreme Court freed up regulators to review costs, regardless of whether they were incurred or forecasted, utilizing whichever statutorily compliant and reasonable test that the regulator chose.[4]

In this article, we canvass the case law that addressed the question of prudence. We observe that while courts may have suggested that the presumption of prudence was a legal doctrine of public utility law, it never had much effect in reality. This makes the point that post *ATCO* and *OPG*, we do not anticipate a fundamental change in regulatory policy. We conclude by arguing that regulatory decisions will continue to balance the interests of customers and utilities as they always have. In fact, the removal of the doctrine may even help utilities in the long run.

II. The Prudent Investment Test – The Case Law

a. The American Experience

Before examining the Canadian case law, a brief digression on the American experience is necessary to explain where the term "prudent investment" test or rule came from. The prudent investment test was first proposed by United States Supreme Court Justice Brandeis in his concurring dissent in *Southwestern Bell Telephone Co v Public Service Commission of Missouri*.[5] Justice Brandeis, however, did not propose the test as a presumptive test that granted utilities a presumption of prudence, but rather he proposed the test as an easier and

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1 See for example *Power Workers' Union (Canadian Union of Public Employees, Local 1000) v Ontario (Energy Board)*, 2013 ONCA 359, 116 OR (3d) 793 ; Section III of Moin A. Yahya, "ATCO Pensions, Ontario Hydro, Prudency, and Reasonableness: a Case Comment on Ontario (Energy Board) v Ontario Power Generation Inc. & ATCO Gas and Pipelines Ltd. v Alberta (Utilities Commission)" (2015) 3:4 Energy Regulation Quarterly 49, online: ERQ < http://www.energyregulationquarterly.ca/case-comments/atco-pensions-ontario-hydro-prudency-and-reasonableness-a-case-comment-on-ontario-energy-board-v-ontario-power-generagtion-inc-atco-gas-and-pipeines-ltd-v-alberta-utilities-commission >.

2 *ATCO Gas and Pipelines Ltd v Alberta (Utilities Commission)*, 2015 SCC 45, [2015] 3 SCR 219 [*ATCO*].

3 *Ontario (Energy Board) v Ontario Power Generation Inc*, 2015 SCC 44, [2015] 3 SCR 147 [*OPG*].

4 See the discussion in Yahya, *supra* note 1.

5 *Southwestern Bell Telephone Co v Public Service Commission of Missouri*, 262 US 276 (1923).

more sensible method for determining the fair return allowed to utilities. At that time, the test was whether the rates allowed to the utility were based on the fair value of the utilities' property, a test that Brandeis argued was "legally and economically unsound."[6] Brandeis's proposed test was meant to shift the focus from fair market valuations of the utilities to historical costs.

The U.S. Supreme Court adopted Brandeis's view and shifted away from fair value as the basis for rate-setting in *FPC v Hope Natural Gas Co.*[7] The Court held that the regulator was not bound to use any single formula in determining rates[8] and that what mattered was that the rates allowed were sufficient for the maintenance of financial integrity of the utility, the attraction of capital, and the compensation of investors for the risks assumed when they invested in the utility.[9] While the Court cited Justice Brandeis's dissent for this proposition, the Court did not adopt any presumption of prudence for historically incurred costs.

Indeed, many years later, the Court in *Duquesne Light Co v Barasch,*[10] reiterated that there was no single ratemaking theory mandated by the Constitution. The Court in *Duquesne* upheld the disallowance of millions of dollars expended on a set of unbuilt power plants that were no longer needed. In doing so, the Court rejected the idea that the Court should adopt the "prudent investment rule", whereby utilities would be able to earn a rate of return on all prudent investments, as a constitutional safeguard for utilities.[11]

b. The Canadian Cases: The Supreme Court

When one turns to Canadian case law, the jurisprudence is no different. The foundational case on the question of public utility rates is *Northwestern Utilities Ltd v City of Edmonton.*[12] The case is often cited for Justice Lamont's famous adage that duty of the regulator was "fair and reasonable rates; rates which … would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested."[13] What is often overlooked when citing the case are the actual facts of the case. Alberta's Board of Public Utility Commissioners had previously set Northwestern Utilities' gas rates, which included a 10 per cent return on investment. A few years later, Northwestern Utilities' applied for a continuation of the rates, but the Board reduced the rate of return to 9 per cent, without a hearing but simply based on the "altered conditions of the money market".[14] The Supreme Court of Canada upheld the Board's decision, stating that the question of a fair rate of return is largely one of opinion which can be left to the Board's expertise. While the case did not address the question of prudence, it demonstrates the high level of deference to the Board's expertise in determining the rate of return even in the absence of a formal hearing.

Many years later, the Supreme Court held that regulatory boards, barring explicit statutory language, had an obligation to provide a fair return to utilities for prudently acquired investments.[15] Nonetheless, the Court held that such boards can consider all matters which they deem proper since there is no single definition of a fair return. The Court did not address the question of whether there was a presumption of prudence for historically incurred costs.

Even when the Supreme Court overturned a regulator's determination of how to allocate the proceeds of the sale of a utility's asset,[16] the Supreme Court nonetheless mentioned that "the regulator limits the utility's managerial discretion over key decisions, including prices, service offerings and the prudency of plant and

6 *Ibid* at 290. The test at the time was based on the case of *Smyth v Ames*, 169 US 466 (1898).
7 *FPC v Hope Natural Gas Co*, 320 US 591 (1944).
8 *Ibid* at 602.
9 *Ibid* at 603.
10 *Duquesne Light Co v Barasch*, 488 US 299 (1989).
11 *Ibid* at 315.
12 *Northwestern Utilities Ltd v City of Edmonton*, [1929] SCR 186.
13 *Ibid* at 192-193. Justice Lamont went on to state the test for a fair return as:
"By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise."
14 *Ibid* at 186-187.
15 *British Columbia Electric Railway Co v Public Utilities Commission of British Columbia*, [1960] SCR 837.
16 *ATCO Gas and PipelinesLtd v Alberta (Energy and Utilities Board)*, 2006 SCC 4 [Stores Block].

equipment investment decisions."[17]

Prior to his elevation to the Supreme Court, Justice Rothstein addressed the question of the proper rate of return in a Federal Court of Appeal judgment.[18] While the judgment repeatedly acknowledged that the allowed rate of return would be based on prudently incurred costs, the judgment accepted that "there are numerous costing issues that may be subject to challenge [such as] … whether costs have been, or are being, prudently incurred".[19] It should have been no surprise, therefore, that Justice Rothstein, after his elevation to the Supreme Court, rejected the idea that there was a presumption of prudence in the twin cases of *ATCO* and *OPG*.[20]

c. The Canadian cases: The Appellate Courts

The lack of presumption of prudence in both the U.S. and Canada's Supreme Court's jurisprudence raises the question of where did this popular view come from? The answer is that regulatory agencies and some appellate courts had articulated tests that suggested a presumption of prudence. These statements, nonetheless also have suggested that such a presumption can be rebutted. The resolution of almost all of the cases suggests that overcoming the presumption was not that high of a hurdle. This is because, practically speaking, any rate hearing will always involve evidence presented by the utility that will be thoroughly tested by the boards' staff and/or interveners. Hence, even if the presumption existed in favor of the utilities, the utilities in making their case before a regulatory agency would be silly if they simply presented expenditures with no supporting evidence whatsoever on the grounds that such expenditures are presumed to be prudent. The Agency staff and interveners would ask so many questions by interrogatories or during the hearing that the utility would ultimately be able to, or not, justify the expenditures. As such, the idea that the presumption of prudence has never been of any practical use for the utilities.

The Ontario Energy Board (OEB), for example had developed the test as a policy tool that was seemingly enshrined as a legal doctrine by the Court of Appeal for Ontario in *Enbridge Gas Distribution Inc v Ontario Energy Board* (2006).[21] In that case, Enbridge had appealed a decision from the Ontario Energy Board, in which the Board found that Enbridge's costs were not prudently incurred and therefore could not be passed on to consumers. The Ontario Divisional Court allowed Enbridge's appeal, stating that the Board used hindsight in its evaluation of prudence but Court of Appeal reversed. The Court listed some of the principles behind OEB's prudent investment test as follows:

- Decisions made by the utility's management should generally be presumed to be prudent unless challenged on reasonable grounds.

- To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.

- Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.

- Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time.[22]

After reciting the test with approval, the Court of Appeal nonetheless upheld the OEB's rate determination for Enbridge. In two subsequent cases the Court of Appeal continued to confirm the OEB's power to set rates using whichever methodology it saw fit as long as the OEB's decision was reasonable or not legally in error. In *Toronto Hydro-Electric System Ltd v Ontario (Energy Board)*,[23] the OEB imposed on the

17 *Ibid* at para 4.
18 *TransCanada Pipelines Ltd v National Energy Board*, 2004 FCA 149.
19 *Ibid* at para 34.
20 See discussion *supra* note 1.
21 *Enbridge Gas Distribution Inc v Ontario Energy Board*, 210 OAC 4.
22 *Ibid* at para 10.
23 *Toronto Hydro-Electric System Ltd v Ontario (Energy Board),* 2010 ONCA 284, 99 OR (3d) 481.

utility the condition that it obtain approval from a majority of its independent directors prior to paying dividends. The Court upheld the OEB's imposition of that condition stating that the Board's condition was within its jurisdiction of rate setting. While not quite a prudence case, the OEB was concerned with the lack of possible expenditures on capital because of excessive dividend payouts. The Court noted that:

> The principles that govern a regulated utility that operates as a monopoly differ from those that apply to private sector companies, which operate in a competitive market. The directors and officers of unregulated companies have a fiduciary obligation to act in the best interests of the company (which is often interpreted to mean in the best interests of the shareholders) while a regulated utility must operate in a manner that balances the interests of the utility's shareholders against those of its ratepayers. If a utility fails to operate in this way, it is incumbent on the OEB to intervene in order to strike this balance and protect the interests of the ratepayers.[24]

In *Great Lakes Power Ltd v Ontario (Energy Board)*,[25] the Court almost seemed to move away from the presumption of prudence, when the Board denied the power company's request to recover costs through its rates without first being reviewed for reasonableness. The utility appealed, which was dismissed by both the Divisional Court and the Court of Appeal. The Court stated that "a utility must undergo a prudency review before passing along its costs to consumers", and without doing so it "is not entitled to the benefit of an approved rate of return."[26]

The presumption of prudence rule, therefore, seems to have only been enforced only once against the OEB, and that was in very case that led to the Supreme Court's judgment in *OPG*, namely *Power Workers' Union, Canadian Union of Public Employees, Local 1000 v Ontario Energy Board*.[27] Therefore, although the test was repeatedly recited by the Court of Appeal of Ontario, the only time it decided to give the test some teeth, the Supreme Court reversed.

Outside Ontario, other appellate courts may have mentioned a presumption of prudence every now and then, but the outcomes of the appeals always were in favor of the regulator. Consider for example, an earlier dispute between ATCO Electric and the Alberta's Energy and Utilities Board (EUB).[28] ATCO Electric had applied to the EUB for rate approvals for the 1999/2000 and 2001/2002 time periods using negotiated settlements. The EUB approved the applications, but denied and reduced carrying costs for particular deferral accounts in three decisions.[29] ATCO appealed arguing that the board should have provided the utility with fair and reasonable compensation for all its costs, as the Board could modify its previous approvals of negotiated settlements to allow for the recovery of certain carrying costs. The Court dismissed the appeal and upheld the Board's decision, stating that the EUB's duty to act in public interest did not include "saving a utility from itself."[30] The Board had discretion in fixing just and reasonable rates, which did not necessarily mean the lowest possible costs, but should allow the utility a "reasonable opportunity to recover its costs, providing they are prudent."[31] The Court approvingly cited the EUB's observation that "while prudent costs does not mean the lowest possible costs [,] financing costs that are unnecessary and inflated, or alternatively, result in windfall profits to the utility cannot be considered prudent."[32] The Court even went on to state that a:

> utility is not entitled to receive a higher rate of return on prudent

24 *Ibid* at para 50.
25 *Great Lakes Power Ltd v Ontario (Energy Board),* 2010 ONCA 399.
26 *Ibid* at para 22.
27 *Power Workers' Union*, *supra* note 1 reversed by *OPG, supra* note 3.
28 *ATCO Electric Ltd v Alberta (Energy and Utilities Board)*, 2004 ABCA 215.
29 *Re Year 2000 Outstanding Matters Deferral Accounts (Other than Pool Price) Part B* (27 November 2001), 2001-83; *Re Genco & Disco 2000 Pool Price Deferral Accounts Proceeding* (12 December 2001), 2001-92; *Re 2000 Pool Price Deferral Accounts Proceeding* (22 December 2001) 2001-93.
30 *Supra* note 28 at para 9.
31 *Ibid* at para 131.
32 *Ibid* at para 179 (citations omitted).

> expenditures simply because of the risk the Board will deny recovery of imprudent ones. To accede to this argument would reward imprudence. This cannot be. ATCO – and not its customers – bears the risks associated with any improper expenditures on its part.[33]

This suggests that the Court of Appeal did not view historically incurred costs as presumptively prudent, but rather placed the onus on the utility to show their prudence.

A year later, the Alberta Court of Appeal actually adopted the prudent investment test, presuming the prudence of incurred costs, but still upheld an EUB ruling against ATCO Gas. In 2001, ATCO Gas had applied for an adjustment to its gas cost recovery rates in order to minimize the balance of its deferred gas account.[34] The EUB held that ATCO had acted imprudently in its practice of withdrawing gas from one of its facilities, leading to $4 million in savings that could have been realized. The EUB ordered ATCO to refund the amount to customers via its rates. ATCO appealed on the basis that the Board did not use the proper test for prudence, but the Court of Appeal dismissed the appeal.[35] The Court cited approvingly the EUB's test of prudence, namely that:

> a utility will be found prudent if it exercises good judgment and makes decisions which are reasonable at the time they are made, based on information the owner of the utility knew or ought to have known at the time the decision was made. In making decisions, a utility must take into account the best interests of its customers, while still being entitled to a fair return.[36]

The Court noted that a presumption of prudence would place the onus on the party questioning the prudence of the utility's decisions, but once rebutted, the prudence of the decision would be reviewed by regulator using a reasonableness test.[37] The Court was more concerned with the EUB acknowledging the presumption of prudence, as opposed to how the EUB went about evaluating the prudence of ATCO's decisions.[38] The actual evaluation of prudence, the Court held, was a question of fact, something that could not properly be presented to the Court.[39]

Although the case law from other jurisdiction have not spoken directly on the presumption of prudence, we note that other provincial appellate courts have deferred to regulators when it comes to the questions of determining rates.[40] This suggests that, as George Vegh observed many years ago, there is no doctrine of Canadian public utility law.[41] But that is not to say that the public utility regulation is lawless and arbitrary. Rather, the practice of public utility regulation, and specifically when it comes to determining what costs to be recovered in rates, is highly nuanced and developed in the regulatory bodies, as opposed to the courts.

III. Prudence back at the Agencies

The Supreme Court's removal of a formal presumption of prudence from the doctrine has not changed past practices regarding evaluating prudence at the various agencies. Consider for example, Direct Energy Regulated Services' (DERS) application to the Alberta Utilities Commission (AUC) to recover from its customers the costs it incurred settling a class-action against it.[42] The class-action was brought against DERS

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33 *Ibid* at para 186.

34 *Re Methodology for Managing Gas Supply Portfolios and Determining Gas Cost Recovery Rates Proceeding and Gas Rate Unbundling Proceeding*, 2001-110, online: AUC <http://www.auc.ab.ca/applications/decisions/Decisions/2001/2001-110.pdf>.

35 *ATCO Gas and Pipelines Ltd v Alberta (Energy and Utilities Board)*, 2005 ABCA 122.

36 *Ibid* at para 22.

37 *Ibid* at para 66.

38 *Ibid* at para 74.

39 *Ibid.*

40 See e.g. *Consumers' Assn of Canada (Manitoba) Inc et al v Manitoba Hydro, Electric Board,* 2005 MBCA 55; *BC Hydro and Power Authority v Terasen Gas (Vancouver Island) Inc*, 2004 BCCA 346; *Re Section 101 of the Public Utilities Act (Newfoundland)*, [1998] 164 Nfld & PEIR 60; *Newfoundland Light & Power Co v Board of Commissioners of Public Utilities*, [1987] 37 DLR (4th) 35, 4 ACWS (3d) 1 (Nfld CA); *Re City of Dartmouth*, (1977) 17 NSR (2d) 425.

41 George Vegh, "Is there a Doctrine of Canadian Public Utility Law?" (2007) 86:2 Can Bar Review 319.

42 *Direct Energy Regulated Services: 2015 Late Payment Penalty Charge Settlement Agreement* (10 August 2016), 20732-D01-2016, online: AUC <http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2016/20732-D01-2016.pdf>.

for improper late-penalty charges that it had been charging regulated customers in the past. The AUC could have easily been emboldened by the two recent Supreme Court cases and decided that such costs were imprudently incurred. Instead it went through a detailed analysis of why DERS settled the class-action lawsuit and how the settlement could positively impact its customers. The AUC allowed DERS to recover 75 per cent of the costs related to its defense of the class-action despite strong opposition from a customer group.[43] One member of the AUC panel that approved the recovery of the costs, even felt compelled to concur separately to express his discomfort at the approved recovery.[44] The full consideration of these difficult issues were ultimately resolved mostly in DERS' favor, demonstrating that the removal of the presumption can still result in satisfactory outcomes that are not all or nothing.[45]

The AUC also recently issued a bulletin seeking commentary on whether it should conditionally exempt owners of public utilities from seeking the AUC's approval prior to issuing equities and long-term debt.[46] Perhaps, because of the two recent decisions by the Supreme Court, the AUC did not feel that it would be hamstrung by imprudent debt or equity issuances, and notes in the bulletin that "[n]othing in this [proposed] rule relieves [an] owner of a public utility from the necessity of demonstrating the prudence of an incurred cost of debt or equity in applicable Commission rate proceedings."[47] A presumption of prudence may have made the AUC more hesitant to remove its supervisory powers over the issuance of debt and equity. As such, if the proposed rule goes forward, this will result in less regulatory burdens for the utilities.

IV. Conclusion

The presumption of prudence may have been a live legal doctrine, albeit for a short period of time, but it never really had any teeth. Prior to the recent Supreme Court cases on the question of prudence, courts at best paid lip service to the doctrine evidenced by all the cases that affirmed the various boards and commissions when prudence was in question. The death of the doctrine, however, means that regulators, utilities, and customers can work on sensible solutions at the regulatory agencies, which will benefit customers and utilities alike. ■

43 *Ibid* at para 4.
44 *Ibid* at paras 252-257.
45 See also *AltaLink Management Ltd: 2012 and 2013 Deferral Accounts Reconciliation Application* (6 June 2016) 3585-D03-2016, online: AUC <http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2016/3585-D03-2016.pdf>.
46 Alberta Utilities Commission, *AUC Bulletin 2016-13* (27 May 2016), online: AUC <http://www.auc.ab.ca/news-room/bulletins/Bulletins/2016/Bulletin%202016-13.pdf>.
47 *Ibid* at 3.

ALBERTA UTILITIES COMMISSION CONFIRMS IT HAS NO JURISDICTION TO ASSESS CROWN CONSULTATION

*Martin Ignasiak, Jessica Kennedy, Justin Fontaine**

On October 7, 2016, the Alberta Utilities Commission (AUC or Commission) confirmed it has no jurisdiction to consider or assess the adequacy of Crown consultation with Aboriginal groups that may be affected by a project under review. The ruling was issued as part of the AUC's process to consider the Fort McMurray West 500-kV Transmission Project (AUC Proceeding 21030)[1] marks the first occasion that the Commission has explicitly considered and ruled on this jurisdictional issue. Subject to the outcome of an appeal filed on November 4, 2016 by Gunn Métis (Local 55) with the Alberta Court of Appeal, this ruling will help guide the scope of future facilities proceedings before the AUC.

Background

Over the last several years, the issue of whether a tribunal has the jurisdiction to review and consider Crown consultation with Aboriginal groups has arisen in several contexts in Alberta. Much of the debate has followed the 2010 Supreme Court of Canada ruling in *Rio Tinto Alcan Inc v Carrier Sekani Tribal Council*[2] (*Carrier Sekani*), which found that the B.C. Utilities Commission had the jurisdiction to consider whether the Crown had satisfied its constitutional duties to consult with Aboriginal people in relation to an application by the Crown to obtain approval of an Energy Purchase Agreement.

In 2012, the Alberta Energy Resources Conservation Board (ERCB) – which, at the time, had similar statutory powers to the AUC – considered whether it had jurisdiction to determine the adequacy of Crown consultation in relation to the Osum Oil Sands Corp. Taiga Project.[3] The party responsible for raising the constitutional question, Cold Lake First Nation (CLFN), argued that, for the ERCB to decide matters in the public interest, it must necessarily assess whether Crown obligations were fulfilled.

The ERCB ultimately concluded that it did not have jurisdiction to assess the adequacy of Crown consultation. It found that, although it had the power to decide constitutional questions, such questions must relate to the Board's statutory mandate. The ERCB found nothing in its mandate to extend its authority to review Crown consultation with respect to Aboriginal or treaty rights in circumstances where the Crown is not the applicant. In support of its decision, the ERCB referenced *Dene Tha' First Nations v Alberta (Energy and*

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1 *Fort McMurray West 500-kV Transmission Project, Ruling on jurisdiction to determine the questions stated in the Notices of Questions of Constitutional Law*, AUC Proceeding 21030.

2 *Rio Tinto Alcan Inc v Carrier Sekani Tribal Council*, 2010 SCC 43 [*Carrier Sekani*].

3 *Osum Oil Sands Corporation's Taiga Project, Reasons for July 17, 2012 Decision on Notice of Question of Constitutional Law*, Osum Oil Sands Corp, Taiga Project, August 24, 2012.

4 *Dene Tha' First Nations v Alberta (Energy and Utilities Board)*, 2005 ABCA 68 at para 28.

Utilities Board)[4] and distinguished *Carrier Sekani* on the basis that the applicant was a private entity.

CLFN subsequently reached an agreement with the proponent and withdrew its objection to the project under review by the ERCB. CLFN appealed the ERCB's jurisdictional decision to the Alberta Court of Appeal, but Justice Berger denied leave on the basis of mootness.[5]

Similar issues were raised in the context of the Joint Review Panel that considered the Jackpine Mine Expansion Project. The decisions in that case were influenced in part by the terms of the Joint Review Panel Agreement.[6] As of June 2013, the ERCB became the Alberta Energy Regulator (AER) under the *Responsible Energy Development Act*.[7] This statute addressed the issue for energy resource projects by explicitly stating that the AER does not have the authority to consider the adequacy of Crown consultation (section 21). However, that act does not apply to the AUC.

More recently, the Commission had occasion to determine whether it has jurisdiction to assess the adequacy of Crown consultation in an application by EPCOR Distribution & Transmission Inc. (EDTI) to expand a substation. The Samson Cree First Nation provided a Notice of Question of Constitutional Law (NQCL) with respect to the adequacy of Crown consultation and on March 3, 2016, the Commission dismissed the NQCL. On May 13, 2016, the Commission provided its reasons.[8]

With respect to the NQCL, the Commission held that the only consultation required in the circumstances was the consultation conducted by EDTI in accordance with the Commission's requirements. The Commission found that the NQCL could be dismissed because Samson Cree First Nation, despite having concerns regarding the adequacy of consultation prior to the hearing, failed to give notice as required by the *Administrative Procedures and Jurisdiction Act*[9] and Schedule 2 of the *Designation of Constitutional Decision Makers Regulation*[10] (the *Regulation*), which resulted in undue prejudice to the Crown, the applicant and the integrity of the Commission's hearing process. The Commission did not, however, explicitly deal with the question of whether the AUC had the jurisdiction to consider the questions posed in the NQCL.

The October 7, 2016 decision

The NQCLs in the present case were brought before the Commission by several First Nations and Métis groups (collectively, the Aboriginal Groups). The NQCLs posed the following questions:

> 1. Has the Crown, through the regulatory process or otherwise, discharged its duty to consult and accommodate SCFN and BLCN with respect to adverse impacts arising from the Project on the rights guaranteed to SCFN and BLCN pursuant to Treaty, the *Natural Resources Transfer Agreement, 1930 ("NRTA")* and section 35 of the *Constitution Act, 1982?*
>
> 2. Can the Alberta Utilities Commission ("AUC") find the project is in the public interest, pursuant to subsection 17(1) of the *Alberta Utilities Commission* Act, in the absence of adequate consultation with respect to adverse impacts arising from the Project on the rights guaranteed to SCFN and BLCN pursuant to Treaty, the *Natural Resources Transfer Agreement, 1930*, and section 35 of the *Constitution Act, 1982?*

The Commission held that the Aboriginal Groups provided sufficient information and notice pursuant to the *Regulation*. As such, the Commission was able to rule on the jurisdictional issue.

After reviewing its enabling legislation, the

5 *Cold Lake First Nations v Alberta (Energy Resources Conservation Board)*, 2012 ABCA 304.
6 *Métis Nation of Alberta Region 1 v Joint Review Panel*, 2012 ABCA 352.
7 *Responsible Energy Development Act*, SA 2012, c R-17.3.
8 *EPCOR Distribution & Transmission Inc: Rossdale Substation Building Expansion*, 20581-D02-2016, online: AUC < http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2016/20581-D02-2016.pdf>.
9 *Administrative Procedures and Jurisdiction Act*, RSA 2000, c A-3.
10 *Designation of Constitutional Decision Makers Regulation*, Alta Reg 69/2006, Schedule 2.

Commission held that it has no explicit or implicit duty to assess the adequacy of Crown consultation before making determinations on applications before it where the Crown is not a participant or an applicant before the Commission and where no Crown decision is before the Commission. The Commission held that it is only empowered to determine questions of constitutional law "that are properly before it," adopting the language used in *Carrier Sekani*.

The Commission upheld the 'Crown applicant' distinction with reference to the Federal Court of Appeal decisions in *Chippewas of the Thames First Nation v Enbridge Pipelines Inc* (*Chippewas*)[11] and *Standing Buffalo Dakota First Nation v Enbridge Pipelines Inc* (*Standing Buffalo*).[12] It was significant that the Federal Court of Appeal in *Chippewas* distinguished *Carrier Sekani* from *Standing Buffalo* on the basis that the Crown was not a participant in the hearing process at issue in *Standing Buffalo*.

Finally, the Commission held that assessing Crown consultation would be premature as Crown consultation processes were not exhausted by the hearing process, rather the hearing process was but one component of a broader consultation process. For the foregoing reasons, the Commission declined jurisdiction over assessing the adequacy of Crown consultation in the context of the transmission facility applications.

Conclusion and implications

The AUC's October 7, 2016 ruling clearly articulates the AUC's view that it does not have the jurisdiction to consider the adequacy of Crown consultation where the applicant is a private entity. For the AUC, issues regarding Crown consultation and impacts on Aboriginal groups are most likely to arise in the context of facilities applications, such as transmission lines and power (including wind, hydro and gas) plants. The ruling provides some assurance to proponents of these projects that, going forward, the Commisison will no longer need to postpone regulatory proceedings to consider this question. It also confirms that the AUC's focus will continue to be on the proponent's consultation with stakeholders, including Aboriginal groups, pursuant to AUC requirements and guidelines. This may help to limit the scope of matters addressed within AUC proceedings where Aboriginal groups are intervening.

As a caution, we note that the AUC's ruling does not have binding precedential value on future AUC decisions. However, given the history on this issue and the widely recognized value in maintaining a consistent approach across applications, future AUC decision-makers are likely to follow this approach. Further, as previously noted, on November 4, 2016 Gunn Métis (Local 55) filed an application to appeal the AUC's ruling to the Alberta Court of Appeal. ■

11 *Chippewas of the Thames First Nation v Enbridge Pipelines Inc*, 2015 FCA 222 [*Chippewas*].
12 *Standing Buffalo Dakota First Nation v Enbridge Pipelines Inc*, 2009 FCA 308 [*Standing Buffalo*].