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# ENERGY REGULATION QUARTERLY

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## EDITORIAL

*Rowland J. Harrison, Q.C. and Gordon E. Kaiser, FCI Arb*

## ARTICLES

**The Crown's Duty to Consult and the Role of the Energy Regulator**

*Keith B. Bergner*

**The 2013 North American Natural Gas Market - A Year in Review**

*Gordon Pickering*

**Fostering Competition Amongst Regulated LDCs: The Dutch Experience**

*Dr. Hugo Schotman*

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**Northern Gateway: Round no. 1**

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*David MacDougall*

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*Helen T. Newland*

**Let the Eastern Bastards Freeze in the Dark**

*Sean Conway*

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# **ENERGY REGULATION QUARTERLY**

WINTER 2014, VOLUME 2

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

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# EDITORIAL

## 2013: A CHALLENGING YEAR FOR CANADIAN ENERGY REGULATORS

*Rowland J. Harrison, Q.C. and Gordon E. Kaiser, FCI Arb*

Managing Editors

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It is always useful to look back at the end of each year and analyse the main developments in energy regulation and identify the challenges going forward. That, after all, is one of the purposes of the *Energy Regulation Quarterly*.

Most would agree that 2013 was anything but business as usual. Energy regulators saw substantial price increases, driven by high cost renewables. Huge quantities of new shale gas appeared on the market along with massive pipeline construction. And most important, the demand for energy by most customers declined.

### **The Shale Revolution**

Five years ago there were plans to build a terminal outside Quebec City to receive liquefied natural gas (LNG) from large gas exporters like Russia. Today we are trying to build a pipeline to move natural gas from British Columbia's shale deposits in the northern part of province to the coast at Kitimat where it will be converted to LNG and shipped to Asia.

Five years ago the price of gas was close to \$14 per GJ. The shale gas revolution changed all that - prices at the end of 2013 at both Dawn and Henry Hub were close to \$3 per GJ, driven by natural gas production from Bakken, Eagle Ford, Marcellus and Barnett in the U.S. and Horn River in B.C. The volume of shale gas five years ago was 2 trillion cubic feet per year. By the end of 2013 it was over 8 trillion cubic feet.

This massive shift in production and its implications is set out in some detail in the article in this issue by Gordon Pickering, one

of the world's leading experts on gas markets.

Shale gas is creating important new opportunities, but it is also creating challenges. In Canada, the ability to move this resource to Asian markets is important because the Asian price is as much as three times higher than the North American price, and it helps reduce Canada's dependence on U.S. markets. But building new pipelines is not an easy exercise. There are serious aboriginal and environmental challenges.

Furthermore, the location of significant deposits of shale gas close to markets in the northeastern U.S. has led to one of the most important and difficult regulatory decisions Canada has seen in a long time. The TransCanada mainline was designed to transport 7 billion cubic feet (bcf) of gas per day. By 2013, the volume was down to 1.5 bcf a day due in large part to the increase in U.S. shale gas supply 3 bcf a day in 2006 to 29 bcf per day.

The declining volumes led TransCanada to increase the tolls on the remaining customers to cover their fixed costs. That was not a happy prospect and the National Energy Board (NEB) struggled with the facts. One of the problems was that TransCanada's customers started using lower-cost interruptible service because they knew it wouldn't be interrupted. The NEB's response in the end was to deregulate that aspect of the service and of course prices went up. But that deregulation had unintended consequences and the matter is far from resolved as we go to press. It is entirely possible that the case will have to be reheard on new evidence but that remains to be seen.

### The Great Pipeline Debate

In Canada 2013 was the year of the pipeline. At least five projects were in play.

The most controversial case is the TransCanada Keystone XL line. This project does not directly involve Canadian regulators and approval is currently in the hands of the U.S. president. It has however set the stage for the conflict between pipeline companies and environmental groups. And that issue has become very important to Canadian regulators. One of the stronger cards TransCanada initially had in its hand – energy security for Americans – has diminished because of the aforementioned huge surge in shale gas which promises American energy self-sufficiency by 2035.

Keystone is a big investment for TransCanada. The company has spent \$2.3 billion on the southern portion and estimates additional costs of \$5.4 billion on the northern portion. The U.S. state department's *Final Supplemental Environmental Impact Statement* offers both good news and bad news. This report, released at the end of January 2014, states that a barrel of Alberta oil results in 17 per cent more greenhouse gas emissions than the average barrel refined in the U.S. But it also notes that building the pipeline will not have much impact on climate change because without it Alberta crude will likely be shipped to markets anyways, either by other pipelines or by rail.

There is some truth to that. Major projects are underway to move crude from the Alberta oil sands to the B.C. coast for shipping to Asia. And oil trains are now a regular feature on the landscape. Rail transport accounted for 80,000 barrels a day (b/day) in Canada at the end of 2013 compared to almost nothing two years earlier. And given the disasters in Lac Megantic and elsewhere we are beginning to discover that oil trains are not a better alternative in terms of safety or pollution.

The second major Canadian project under review in 2013 was Enbridge's proposed \$5.5 billion Northern Gateway Pipeline designed to connect oil sands crude to the West Coast where it would be shipped to higher priced international

markets in the Pacific rim. This project also ran into heavy environmental criticism and equally important coastal First Nations opposition. The Joint Review Panel Report recommending approval of the project is reviewed in this issue by Rowland Harrison.

The duty to accommodate First Nations concerns has become a growing responsibility of Canadian energy regulators. Over the last several years both regulators and courts have struggled with this issue. This is an important constitutional issue and Keith Bergner's excellent lead article sets out these developments in a very comprehensive fashion.

The third project of note in 2013 was Kinder Morgan's application to twin its existing oil pipeline from Edmonton to Burnaby, B.C. at a cost of \$5.4 billion. This project would increase the capacity of the pipeline from 300,000 to 900,000 barrels per day. Given that this is an existing line the opposition is not as great as in the Keystone XL or Northern Gateway project. But environmental groups and First Nations are engaged and nothing in the world of pipeline construction is guaranteed.

This concern is borne out in Enbridge's Alberta Clipper project a 1,600 km crude oil line running from Hardisty, Alberta to Superior, Wisconsin. The company had originally understood that a presidential permit to increase the capacity on the line to 800,000 b/day from the current 450,000 b/day would be issued by mid year. But it has been delayed by a request from environmental groups that the state department conduct an inquiry and issue a Supplemental Environmental Impact Statement that considers the cumulative impact of Alberta Clipper and Keystone XL.

The final and, in some ways, most interesting project is TransCanada's most recent initiative – the Energy East pipeline. This is a \$12 billion investment by TransCanada to convert its existing gas pipeline to an oil pipeline running from Alberta to the Quebec border and then build a new pipeline through Quebec and New Brunswick to the Irving refineries on the coast.

In some respects this line is a reaction to the

declining demand for natural gas transportation on the TransCanada Mainline and the recent decision of the NEB on TransCanada's application to revise its tolls on that line.

The Energy East project has an interesting twist. While the federal government and the NEB have exclusive jurisdiction over interprovincial pipelines, the Ontario Minister of Energy has asked the Ontario Energy Board (OEB) to conduct a province wide consultation on the impact of the Energy East proposal. The Minister has asked the Board to consider the impact of the line on Ontario natural gas consumers in terms of rates, reliability and access to supply. The Minister also asked the OEB to consider the impact of the pipeline on safety and environmental issues, the impact on local communities, the impact on First Nations communities and the short and long-term impact on the economy of the province. At the end of this process, which will involve consultations across the province in coming months, the OEB will submit a report to the Minister which will inform an intervention planned by the province in the federal hearing.

### **The No Growth World**

The problems raised by declining demand seen in the TransCanada MainLine case will soon face Canadian local distribution companies particularly in Ontario. Ontario appears to lead the country in the three factors that are causing the drop in energy demand – increased prices, increased energy efficiency and a move to electricity distributed generation.

The recent long-term energy plan (LTEP) issued by the Ontario government offers some interesting insights. In 2005 electricity demand in Ontario was 155 TWh. That dropped to 141 TWh in 2013 - a 9 per cent reduction. In 2011, the average household consumption of electricity was 10 MWh. In 2031 it is predicted to be 7.5 MWh. The Energy Information Agency (EIA) forecasts that lighting per household in 2035 will be 827 kWh per year or 47 per cent below the 2011 level. The average consumption for commercial customers in 2011 was 18 kWh per square of floor space. In 2031 it is forecasted to be 15 kWh per square foot.

Much of these demand reductions are driven by customer reaction to higher prices. In Ontario the Regulated Price Plan (RPP) supply cost for electricity has gone from 5.5 cents in May 2008 to 8.9 cents by the fall of 2013 – an increase of 63 per cent. The LTEP forecasts that a typical residential bill in Ontario will go from \$125 a month in 2013 to \$178 per month in 2018 a increase of 42 per cent.

One factor contributing to these price increases is the high cost of renewable electricity now entering the system. This new generation is expensive compared to traditional generation. The last Ontario RPP report indicated that the cost of electricity generated from hydro was 4.8 cents per kWh, and nuclear was 6 cents per kWh. Wind however is 12 cents per kWh while solar is 49 cents per kWh.

Ontario has also been a leader in conservation. Almost five million customers across Ontario were mandated by the province to adopt smart meters with access to time of use pricing at a cost of \$1 billion. As a result peak demand has dropped by about three per cent or 1,000 MW. In the past, conservation was led by the utilities and in most cases driven by the government.

The role of conservation and its impact on demand will only escalate. The Ontario LTEP states that Ontario will invest in conservation first before new generation. Since 2005, 1,900 MW of electricity demand has been eliminated through conservation. The LTEP report estimates peak reductions from conservation at 1,500 MW in 2015 and almost 3,000 MW by 2030.

Future conservation initiatives however will be different. More will happen on the customer side of the meter, not be driven by the utilities or the government. Customers faced with rising costs will take their own initiatives using up-to-date technology.

Google recently paid \$3 billion to purchase a company called Nest, a supplier of smart thermostats. Smart thermostats may become more important than smart meters. Smart thermostats have the advantage that they connect through the Internet. They can be installed in

minutes not months. The transmission costs are zero. And the devices that communicate with them are already in the customer's hands. They are known as smart phones. In this new world everything is smart: smart meters, smart grid, smart phones and now, smart thermostats.

There are other technologies that will influence behavior on the customer side of the meter. Advanced batteries will lead to cheaper energy storage for electric vehicles, homes and businesses. Electricity storage, which was targeted by the minister in Ontario's LTER, may become the next disruptive technology. This will create some interesting challenges for Canadian energy regulations.

The third factor behind declining demand may be the real game changer. Customers, particularly electricity customers, are moving off the grid, again enabled by technology. In this case it's solar. The solar industry struggled initially. But now prices are dropping rapidly. The average cost of a solar PV panel in 1977 was \$77 per watt. Today these panels can be bought for under a \$1 per watt. Worldwide, new solar generation capacity will soon outstrip wind capacity. In 2013 over \$100 billion of solar systems will be installed accounting for over 100 GW. Today companies are financing residential roof top solar in exchange for the excess power. Moving solar into the commercial market is the next step. Walmart installed over 65 MW of solar in 2013, Costco 39 MW and IKEA 21.5 MW.

Local generation is not restricted to solar. California manufacturers are resorting to self generation and micro turbines causing the share of electricity sold to manufacturing to drop from 33 per cent to 10 per cent. These trends present real problems for utilities. And for regulators.

Energy generation and distribution are industries with high fixed costs. As long as demand grows a substantial amount of incremental revenue drops to the bottom line. But when the opposite occurs and demand declines, profit drops. As customers go off the grid, the remaining customers are

forced to pay more and more of the cost of the fixed assets through higher rates. As rates continue to increase, more customers will find alternatives. This is now known as a utility death spiral.

### **The New Regulatory Challenge**

In some respects last year's TransCanada MainLine case was a wake-up call for those regulating local distribution companies, and indeed those regulators saw troubles coming. The OEB for example will release a study this spring addressing the declining volume issue squarely.

Their recommendations will likely involve a new demand charge because in a world of declining demand, rates can no longer be based solely on volume. But a rate totally dependent on a demand charge can undo all the gains from extensive energy efficiency programs throughout the country. The Ontario demand charge however will be unique in that the amount will depend on the peak usage of the customer. Those with higher peaks will have a higher demand charge than those with a lower peak. Other jurisdictions engaged in this type of analysis include the California Energy Commission which has recently been mandated to undertake a rate review by the State legislature.

The no growth world also poses real problems for incentive ratemaking, which has become the standard bearer in many jurisdictions. The concept is simple enough - the rate increase is limited to an industry price index increase minus a productivity factor. But in a no growth world, there is no productivity increase. When demand falls in an industry with high fixed costs, productivity drops. And not because of inefficiency. The demand decline which drives the drop in productivity is in large part driven by factors that the utility cannot control.

Both gas and electric utilities will face this issue, although the gas utilities are isolated to a degree. Their cost of energy, the natural gas they purchase, has also dropped dramatically in North America because of shale gas. Electric utilities are on the other end of the

spectrum - their cost of energy is being driven up by high-cost renewables and high-cost new construction in traditional generation.

issue of ERQ to know that the next regulatory challenge is on the horizon. ■

The long-term solution to the utility death spiral may require more than new pricing. It may be that if electric utilities are to survive they will have to become integrated energy service companies. For that to happen, regulators and legislators will have to rewrite the rules of the game. The argument is that to survive utilities must be able to participate in the new markets. Policy makers and regulators will have to remove the artificial boundaries that over the years have been created in both product and geographical markets.

Should a local distribution company be prohibited from engaging in generation? It is not just generation. There are a host of other "new" services such as energy storage, energy efficiency and electric vehicle charging that regulators will have to face in the near future. And utilities will argue that they should be able to seek unique new partnerships. At the end of the day, utilities will argue for a level playing field where they can compete with new entrants that are and in turn entering their market.

There may be important advantages. First, it may save the utility. And that everyone would concede, is a good thing. It may also stimulate the development of new technology. These companies have access to capital and knowledge. And they can leverage the core relationship they have with their customers. There will always be a concern that utilities will use revenues from monopoly markets to subsidise activities in competitive markets. But the distinction between these market may be blurring.

The time may have passed for blackline rules that establish a boundary between service activities that in the world of modern technology make less sense.

This is not a simple exercise. Regulators and legislators will struggle. It is a delicate balance. But we only have to look at the TransCanada Mainline decision and other articles in this



# THE CROWN'S DUTY TO CONSULT AND THE ROLE OF THE ENERGY REGULATOR

Keith B. Bergner<sup>1</sup>

## Introduction

This coming fall—November 18, 2014—will mark ten years since the Supreme Court of Canada released two seminal decisions on the Crown's duty to consult Aboriginal peoples: *Haida Nation v. British Columbia (Minister of Forests)*, 2004 SCC 73 and *Taku River Tlingit First Nation v. British Columbia (Project Assessment Director)*, 2004 SCC 74. This was a turning point in one of the most significant developments in the law in recent years as it applies to Canadian provincial and federal energy regulators ("Energy Regulators")—and arguably among the most significant developments in Canadian law generally in recent years—namely,

the emergence and ongoing clarification of the Crown's duty to consult and, if necessary, accommodate Aboriginal peoples.

Ten years ago, issues surrounding Aboriginal rights and title and the Crown's duty to consult Aboriginal peoples inhabited only the periphery of energy/regulatory law and practice. Today, for many Energy Regulators, project proponents, Aboriginal groups and intervenors, these issues have become a critical focus in the regulatory approval processes for major (and not-so-major) projects. As the Supreme Court of Canada aptly noted in a more recent decision:

"In the intervening years [since *Haida*], government–Aboriginal consultation has become an important part of the resource

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<sup>1</sup> Keith Bergner, a partner with the law firm of Lawson Lundell, LLP, practices Aboriginal and regulatory/energy law. <http://www.lawsonlundell.com/team-Keith-Bergner.html>

It is the policy of the Energy Regulation Quarterly to disclose when a contributor acted as counsel or co-counsel in court cases and/or regulatory hearings discussed in an article or case comment. In the spirit of full disclosure, it is noted that Lawson Lundell and Keith Bergner acted as counsel or, in most cases, co-counsel for a party or participant in the following regulatory hearings and appellate court proceedings discussed in this article.

Court Decisions:

- *Rio Tinto Alcan Inc. v Carrier Sekani Tribal Council*, 2010 SCC 43, [2010] 2 SCR 650. (Chris Sanderson, Q.C., Keith Bergner and Laura Bevan representing the Respondent BC Hydro and Power Authority.)
- *Beckman v Little Salmon/Carmacks First Nation*, 2010 SCC 53. (Brad Armstrong, Q.C. and Keith Bergner of Lawson Lundell and Penelope Gawn and Lesley McCullough of the Yukon Department of Justice representing the Appellant Government of Yukon.)
- *Standing Buffalo Dakota First Nation v Enbridge Pipelines Inc.*, 2009 FCA 308; leave to appeal to the Supreme Court of Canada dismissed, December 2010. (Lewis Manning and Keith Bergner representing the Respondent Canadian Association of Petroleum Producers.)
- *Carrier Sekani Tribal Council v British Columbia (Utilities Commission)*, 2009 BCCA 67, appealed to the Supreme Court of Canada. (Chris Sanderson, Q.C., Keith Bergner representing the Respondent BC Hydro and Power Authority.)
- *Kwikwetlem First Nation v British Columbia (Utilities Commission)*, 2009 BCCA 68. (Keith Bergner and Angela Bespflug representing the Respondent BC Hydro and Power Authority.)
- *Brokenhead Ojibway First Nation v Canada (Attorney General)*, 2009 FC 484. (Lewis Manning and Keith Bergner representing the Intervenor Canadian Association of Petroleum Producers.)

Regulatory Proceedings:

- Northern Gateway Pipeline, Report of the Joint Review Panel, December 2013. (Keith Bergner representing the intervenor Canadian Association of Petroleum Producers.)
- Interior to Lower Mainland (ILM) Transmission Project, British Columbia Transmission Corporation, British Columbia Utilities Commission, Reconsideration Decision, February 3, 2011. (Keith Bergner and Michelle Jones representing BC Hydro and Power Authority.)

development process...”<sup>2</sup>

Given the importance of Energy Regulators in the resource development process, issues of the Crown’s duty to consult Aboriginal peoples have also become an important part of the regulatory process. However, the role and function of Energy Regulators in Aboriginal consultation and the review of Aboriginal consultation carried out by others—and how these issues fit as a part of the regulatory process—has often remained poorly understood. Regulators have struggled to define their role and understand their jurisdiction in respect of the complicated legal, historical and social issues raised by such issues.

The meeting of Aboriginal law (and its practitioners) and energy/regulatory law (and its practitioners) has not always been smooth. In the hearing rooms of today’s Energy Regulators, it is not uncommon to see Aboriginal law practitioners/legal counsel (who are well-versed in the law of Aboriginal rights and title and the Crown’s duty to consult) citing reams of Aboriginal case law to an (often somewhat confused) Energy Regulator, while often giving scant treatment to issues regarding the proper role and function of that Energy Regulator. Similarly, it is not uncommon to see Energy Regulators struggle with such submissions and attempting to reconcile such submissions with their legislative role and function—and not finding significant guidance in their legislative job descriptions.

### **Objective and Outline**

This article will suggest that much of the confusion that has plagued this area of the law is a result of failing to properly distinguish between (i) the various legal contexts in which the duty to consult can arise; (ii) the various types of decision-making structures in which Energy Regulators operate; and (iii) the different types of parties (private or Crown agents) that can be applicants or parties before Energy Regulators. What is required is not a search for universal answers that will fit all Energy Regulators and all circumstances. Instead, what is required is an

analytical framework that will assist in clarifying the nature of the consultation obligations and the role of the Energy Regulator in the context of a specific legislative framework, application and applicant.

In an effort to begin discussion of such an analytical framework, this article will suggest:

- There are three distinct legal contexts in Canada that need to be understood—(i) historic treaties; (ii) modern treaties or comprehensive land claims; and (iii) non-treaty areas.
- The Crown’s duty to consult can arise in all three contexts, but purpose, scope and extent of the duty to consult may be different in each context. Some Energy Regulators may encounter more than one such context (sometimes in the scope of a single project application) and must be alert to the potential differences in the ways the duty to consult may apply.
- The duty on an Energy Regulator to consider consultation and the scope of that inquiry depends on the mandate conferred by the legislation that creates the tribunal. The legislature may delegate either, both or neither of the powers to carry out the Crown’s duty to consult and/or determine whether adequate consultation has taken place, as a condition of its statutory decision-making process.
- The precise role of the Energy Regulator may be different depending on the nature of the application before it, the nature of the decision-making structure in place for such applications, and the Applicant before it—particularly whether the Applicant is a private company or a Crown agent.

This article is an attempt to provide a view from the vantage point of the intersection of Aboriginal and regulatory law. Those with an expertise in Aboriginal law may find its treatment of the rich and varied principle and case law of this complex discipline to

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<sup>2</sup> *Rio Tinto Alcan Inc. v Carrier Sekani Tribal Council*, 2010 SCC 43 at para 2, [2010] 2 SCR 650 [*Rio Tinto*].

be somewhat elementary. Those with an expertise in regulatory law may make the same complaint about its treatment of regulatory law and principles. This is perhaps a consequence of attempting to speak to two rather diverse audiences at once. As with so much of Aboriginal law (and with this part of the history of Canada), the dialogue is necessarily a “cross-cultural” discussion, and certain subtleties and nuances are (at least initially) apt to be sacrificed along the way.

More specifically, the objective of this article is to situate and examine the role of the Energy Regulatory in respect of the Crown’s duty to consult. Given the number and diversity of Energy Regulators on the Canadian landscape, this article does not attempt or purport to canvass each and every Energy Regulator and/or consider its legislation. Instead, it sets the more modest objective of attempting to identify and clarify the guiding principles and an analytical framework that apply in defining the role of the Energy Regulator. It is my hope that this effort may be of some use to Canadian Energy Regulators and the myriad parties that appear before them, including project proponents, Aboriginal groups and other intervenors interested in the important (but often misunderstood) role of Canadian Energy Regulators.

This article has organized in the following three parts:

- A. Part I provides a primer on Aboriginal rights and title and outlines three distinct legal contexts that exist in contemporary Canada -- historic treaties, modern treaties and non-treaty areas;
- B. Part II provides a discussion of the sources, purpose and principles applicable to the Crown’s duty to consult Aboriginal peoples and an examination of how the duty applies in each of the three legal contexts identified above;
- C. Part III provides the primary focus of this article in discussing the role of the Energy Regulator in respect of the

Crown’s duty to consult;

The overview of Aboriginal rights and title (Part I) and the Crown’s duty to consult (Part II) provides a foundation for understanding and appreciating the interrelationship between Aboriginal law principles and regulatory/administrative law applicable to Energy Regulators (Part III).

### **Part I: A Primer on Aboriginal Rights and Title in Canada**

Section 35(1) of *The Constitution Act, 1982*<sup>3</sup> states:

“The existing aboriginal and treaty rights of the aboriginal peoples of Canada are hereby recognized and affirmed.”

Behind this simple phrase lies a wealth of diversity and complexity.

In Canada, there are in excess of 600 First Nations, plus numerous Inuit and Métis groups and organizations. These groups comprise numerous, rich and varied linguistic and cultural traditions. Amongst these groups, there is a broad diversity of historical and contemporary circumstances and an equally diverse range of outlook, orientation and approach. Any attempt to categorize such diversity into an artificially small number of legal frameworks risks being accused of being nothing more than generalization on a vast scale. The attempt at creating such a categorization of these legal frameworks is not meant to be disrespectful of the diversity that exists among and between Aboriginal groups but is simply an effort to make such diversity manageable for the non-specialist in Aboriginal affairs and history.

With the above caveat in mind, I suggest that there are, broadly speaking, three legal frameworks applicable to Aboriginal peoples in Canada:

- a. (a) the historic treaties;
- b. (b) the modern treaties/comprehensive

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<sup>3</sup> being Schedule B to the *Canada Act 1982* (UK), 1982, c 11.

land claims; and

- c. (c) the non-treaty context.

Each is discussed further below.

### **Historic Treaties in the Area that is now Canada**

In some parts of Canada, it is becoming increasingly common to hear the phrase: “We are all treaty people.” It is true that treaties between the Crown and Aboriginal peoples exist in many parts of Canada covering the majority of the Canadian land mass. However, in some significant parts of Canada, treaty making remains unfinished business. It is unfortunately not uncommon for non-Aboriginal Canadians to live many years or even their entire lives in a region of Canada not knowing or understanding the treaty arrangements that may have proceeded or accompanied non-Aboriginal settlement in that area.

A comprehensive examination of these treaties (and the rules of interpretation that apply to them) is beyond the scope of this article, but the existing historic treaties can generally be grouped into the following categories:

- *Treaties of Peace and Neutrality (1701-1760)*

These treaties were the product of the British and French seeking military alliances with First Nations in the context of the struggle for the control of North America. For example, the Treaty of Swegatchy and the Huron-British Treaty—both concluded in 1760 at the end of the Seven Years’ War—addressed, *inter alia*, issues such as the protection of First Nation village sites, the right to trade with the British and the protection of traditional practices.

- *Peace and Friendship Treaties (1725-1779)*

These treaties were concluded between the British authorities in Nova Scotia and the Mi’kmaq and Maliseet peoples of the Maritimes.

- *Upper Canada Land Surrenders and the Williams Treaties (1781-1862/1923)*

These treaties focused on land cessions in the Great Lakes region. For the most part, these treaties involved one-time cash payments with ongoing obligations. In 1923, the Williams Treaties focused on land cessions (again for a fixed one-time cash payment) in the region between Georgian Bay, the Ottawa River, Lake Simcoe and the lands west of the Bay of Quinte.

- *Robinson Treaties (1850) and Douglas Treaties (1850-1854)*

The Robinson treaties of 1850 were concluded between William Robinson and the primarily Ojibwa inhabitants of the northern Great Lakes region. The Robinson-Superior Treaty covered the area of the north shore of Lake Superior. The Robinson-Huron Treaty covered the Lake Huron and Georgian Bay areas. These treaties—in contrast to treaties negotiated earlier—contemplated the creation of reserves, annuities and the continued right to hunt and fish.

The Douglas Treaties—14 in all—were concluded from 1850 to 1854 between James Douglas (Chief Factor of the Hudson Bay Company and later governor of the colony on Vancouver Island) and certain First Nations on Vancouver Island. These treaties contemplated the surrender of lands near Hudson Bay Company posts on Vancouver Island in exchange for reserves, payments and the continued right to hunt and fish.

This new approach (recognizing continued rights to hunt and fish) would be further developed in the Numbered Treaties (discussed below).

- *The Numbered Treaties (1871-1921)*

Between 1871 and 1921, Canada undertook 11 “numbered” treaties (i.e. Treaty No. 1, Treaty No. 2, etc.) that

covered the Prairies, northern Ontario and the Peace River and Mackenzie River valleys. These treaties contemplated the surrender of lands in exchange for reserves, payments and the continued right to hunt and fish.<sup>4</sup>

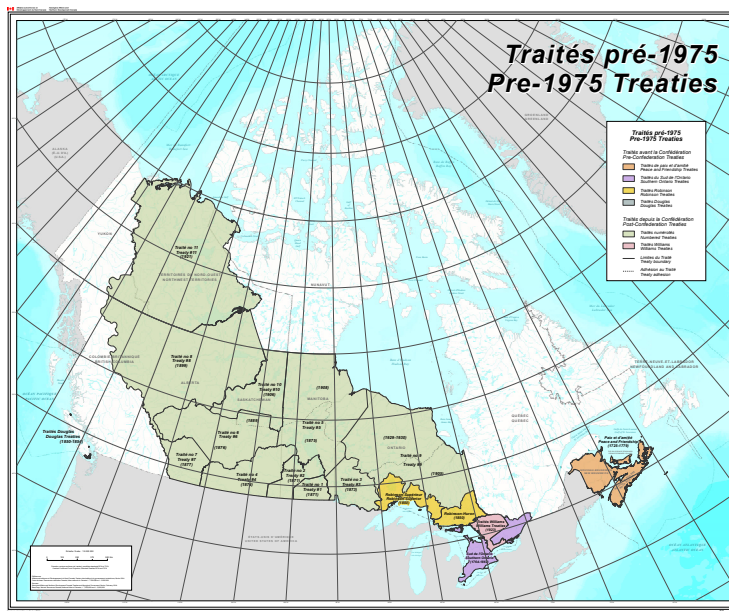
The other commonly employed categorization for these historic treaties is to consider them in the groupings of: (i) Pre-Confederation; and (ii) Post-Confederation treaties—with the dividing line drawn at 1867. The scope and content of the historic treaties remains subject to considerable debate and uncertainty. For example, the “trade clause” in a Peace and Friendship treaty of 1760/61 was the famously the subject of 1999 litigation before the Supreme Court of Canada in *R. v. Marshall*.<sup>5</sup> A rich and detailed jurisprudence has developed regarding the interpretation of these important historic treaties.<sup>6</sup>

The following map<sup>7</sup> shows the approximate

location and boundaries of historical treaties in Canada.

As can be seen from the map, when the historic treaty making process concluded in the early 1900s, large sections of current-day Canada were not covered by treaties—notably the majority of British Columbia, Quebec, Newfoundland, Labrador, the Yukon, and eastern portions of the Northwest Territories and what is now Nunavut.<sup>8</sup>

As discussed below, some of these non-treaty areas were subsequently the subject of modern treaty negotiations. In addition, in some areas where the historic treaties were never fully implemented (notably, for example, in relation to Treaty No. 11 and some of the northern areas of Treaty No. 8), the Crown and the relevant Aboriginal groups have also entered into modern treaty negotiations and in some cases concluded modern agreements.



<sup>4</sup> For further information on treaty making in Canada, including treaty texts and maps, see the material at Aboriginal Affairs and Northern Development Canada: <<http://www.aadnc-aandc.gc.ca/eng/1100100028574/1100100028578>>.

<sup>5</sup> *R v Marshall*, [1999] 3 SCR 456 [*Marshall*]; application for rehearing dismissed *R v Marshall*, [1999] 3 SCR 533.

<sup>6</sup> See for example: *R v Badger*, [1996] 1 SCR 771 at paras 52-58.

<sup>7</sup> Source: Aboriginal Affairs and Northern Development Canada: <[http://www.aadnc-aandc.gc.ca/DAM/DAM-INTER-HQ/STAGING/texte-text/htoc\\_1100100032308\\_eng.pdf](http://www.aadnc-aandc.gc.ca/DAM/DAM-INTER-HQ/STAGING/texte-text/htoc_1100100032308_eng.pdf)>.

<sup>8</sup> It is not uncommon to hear the historic treaties referred to as "covering" some portion of the Province. For example, you will hear that Treaty No 8 "covers" portions of North-East B.C., Northern Alberta, Saskatchewan and the Southern Northwest Territories. However, given that in many places, particularly in the Prairie Provinces, the act of treaty making

### Modern Treaty Making in Canada

The modern treaty process deals with unfinished treaty making in areas of Canada where historic treaties were not concluded. Section 35(3) of *The Constitution Act, 1982*, clarifies:

“For greater certainty ... ‘treaty rights’ includes rights that now exist by way of land claims agreements or may be so acquired.”

There is no bright line separation between the “historic” and the “modern” treaties. The artificial distinction is employed here simply as a matter of convenience. In most attempts at categorization, the first so-called modern day treaty is considered to be the “*James Bay and Northern Quebec Agreement*”, signed in 1975. Perhaps the primary distinguishing feature of the modern treaties is their length and detail—typically consisting of hundreds of pages with numerous detail appendices and maps—compared to the historic treaties.

Mr. Justice Binnie, of the Supreme Court of Canada has observed:

“The increased detail and sophistication of modern treaties represents a quantum leap beyond the pre-Confederation historical treaties ... and post-Confederation treaties such as Treaty No. 8 (1899) ... The historical treaties were typically expressed in lofty terms of high generality and were often ambiguous. The courts were obliged to resort to general principles (such as the honour of the Crown) to fill the gaps and achieve a fair outcome. Modern comprehensive land claim agreements, on the other hand, starting perhaps with the *James Bay and Northern Québec Agreement* (1975), while still to be interpreted and applied in a manner that upholds the honour of the Crown, were nevertheless intended to create some precision around property and governance rights and obligations.

Instead of *ad hoc* remedies to smooth the way to reconciliation, the modern treaties are designed to place Aboriginal and non-Aboriginal relations in the mainstream legal system with its advantages of continuity, transparency, and predictability.”<sup>9</sup>

### Modern Treaty-Making North of 60

The modern treaty making process has, to date, been far more prolific in Northern Canada. Since 1973, 16 comprehensive land claims have been reached in the northern territories (Yukon, the Northwest Territories, and Nunavut).

- In the **Yukon**, there are 14 resident First Nations. To date, land claims agreements with 11 of those First Nations have been concluded and implemented. These 11 are, with the dates their agreements were implemented: the Champagne and Aishihik First Nation (1993); the Teslin Tlingit Council (1993); the Vuntut Gwitchin First Nation (1993); the First Nation of Nacho Nyak Dun (1993); the Little Salmon/Carmacks First Nation (1997); the Selkirk First Nation (1997); the Tr’ondek Hwech’in First Nation (1998); the Ta’an Kwach’an First Nation (2002); the Kluane First Nation (2003); the Kwanlin Dun First Nation (2005); and the Carcross Tagish First Nation (2005).<sup>10</sup>
- In the **Northwest Territories**, to date land claims agreements with the following Aboriginal groups have been concluded and implemented: Inuvialuit (1984), Gwich’in (1992), Sahtu Dene and Métis (1994), and Tli’cho (2005). In the southern part of the Northwest Territories, land claim negotiations continue with a number of First Nations and Métis groups.
- In **Nunavut**, the Nunavut Final Agreement concluded in 1993 led to

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*preceded* the creation of the Prairie Provinces, the more accurate statement is that these Provinces actually “cover” the treaties.

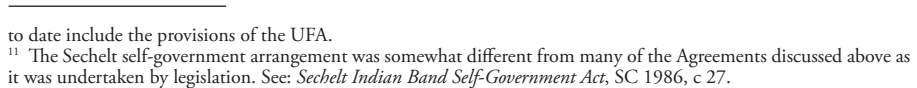
<sup>9</sup> *Beckman v Little Salmon/Carmacks First Nation*, 2010 SCC 53 at para 12, [2010] 3 SCR 103 [Beckman] [Little Salmon].

<sup>10</sup> The principal terms of the land claims agreements with Yukon First Nations are set out in the *Umbrella Final Agreement* (the “UFA”). Among other things, the UFA includes provisions related to ownership of lands by Yukon First Nations (“Settlement Land”) and management of lands and resources in Yukon. The final agreements implemented

Modern day treaties in Canada generally have two aspects: (i) comprehensive land claim settlements; and (ii) self-government agreements. Some agreements address both lands claims and self-government. However, some agreements address only land claims issues, but leave self-government negotiations to be concluded separately. For example, in the Northwest Territories, the Tli'cho Final Agreement (2005) addresses both land claims and self-government; however, the earlier agreements in the territory (Inuvialuit, Gwich'in and Sahtu) addressed only comprehensive land claims and left self-government to subsequent (and ongoing) negotiations.

In the rest of Canada (south of the 60<sup>th</sup> parallel) during this same time period, a relatively small number of other comprehensive land claims and self-government arrangement have been

- In Quebec, there was the aforementioned *James Bay and Northern Quebec Agreement* (1977) and the *Northeastern Quebec Agreement* (1978).
- The offshore island and marine areas adjacent to Quebec were the subject of the *Nunavik Inuit Land Claims Agreement* (2008) and the *Eeyou Marine Region Land Claims Agreement* (2012).
- Northern Labrador was the subject of the *Labrador Inuit Land Claims Agreement* (2005).
- In British Columbia, there has been the *Nisga'a Final Agreement* (2000), the *Tsawwassen First Nation Final Agreement* (2009) and *Maa-nulth First Nations Final Agreement* (2011). There have also been self-government arrangements with the Sechelt Indian Band<sup>11</sup> (1986) and *Westbank First Nation Self-Government Agreement* (2005).



The following map shows the locations of Modern Treaties, including both Comprehensive Land Claims and Self-Government agreements.<sup>12</sup>

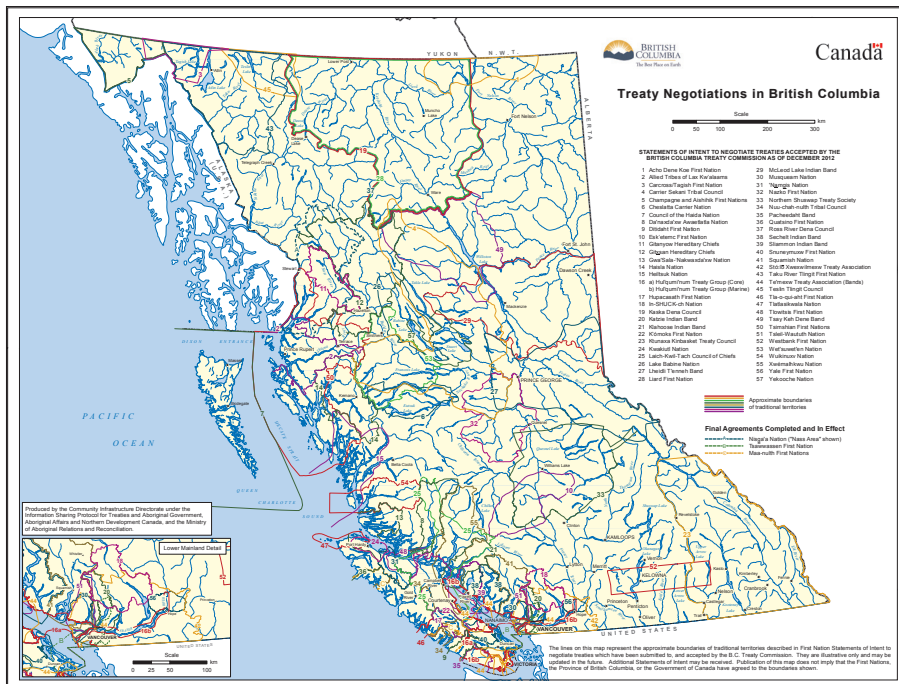
### *The BC Treaty Commission Process*

British Columbia is where there is perhaps the largest concentration of unfinished treaty business in Canada. As discussed above, there are no historic or modern treaties coving the majority of British Columbia. However, the governments of Canada and British Columbia have been engaged in treaty negotiations with numerous First Nations pursuant to the B.C. Treaty Commission Process. The Treaty Commission and the treaty process were established in 1992 by agreement among Canada, B.C. and the First Nations Summit.

The following map shows the numerous (overlapping) claims submitted to the B.C. Treaty Commission process:<sup>13</sup>

Some Indian Bands in British Columbia are negotiating individually, while other Bands have combined to form larger treaty negotiation groups. Of the more than 200 Indian Bands in British Columbia there are slightly more than 100 that are participating in the B.C. Treaty Commission process—grouped into about 60 treaty negotiations tables.<sup>14</sup> Of these 60 treaty negotiation groups:

- 2 (Maa-nulth and Tsawwassen) are implementing treaty agreements;
- 3 have completed final agreements that are not yet implemented;
- 5 are in final agreement negotiations or completed agreements in principle;
- 10 are in “advanced” agreement-in-principle negotiations;
- 20 are in “active” agreement-in-principle negotiations; and
- 20 are described as “not currently



<sup>12</sup> Source: <[http://www.aadnc-aandc.gc.ca/DAM/DAM-INTER-HQ-AI/STAGING/texte-text/mprm\\_pdf\\_modrn-treaty\\_1383144351646\\_eng.pdf](http://www.aadnc-aandc.gc.ca/DAM/DAM-INTER-HQ-AI/STAGING/texte-text/mprm_pdf_modrn-treaty_1383144351646_eng.pdf)>.

<sup>13</sup> Source: BC Treaty Commission: <<http://www.bctreaty.net/files/negotiations.php>>.

<sup>14</sup> The astute observer of the map will notice that, while there are numerous overlapping treaty claims, there are also large areas that are not covered by treaty claims. There are a large number of BC First Nations that have chosen to pursue their claims outside the context of the BC Treaty Commission process.

negotiating a treaty.”

Many observers have expressed frustration at the relatively slow pace of treaty negotiations and the fact that—following over 20 years of the BC Treaty Commission process—there are no more than a handful of final agreements. However, when one considers that the current situation was created over the course of a few hundred years, it is perhaps unrealistic to hope or expect that treaty negotiations will be concluded quickly. In the past several years, a number of First Nations in BC have signed “incremental” agreements that provide the First Nation with access or title to a limited number of parcels of Crown land in advance of a full treaty agreement.

#### *Modern Land Claims – Common Features*

Given that the modern treaty making process in Canada already spans a four decade history, it is not surprising that there is considerable variation in the approach and details of the above mentioned modern treaties. Again at the risk of generalization, the following discussion will focus on the common elements. A common approach in these agreements, which each contain their own structural and procedural arrangements, is as follows:

- I. a specific tract of land is identified and confirmed as land held by the Aboriginal group in fee simple;
- II. a larger tract of land is identified as a management area, within which the Aboriginal group, federal government and either territorial or provincial government participate in land use planning and land use permitting and approvals; and
- III. a larger area within which certain land use rights, such as hunting, fishing, trapping and gathering, continue to apply. This larger area often overlaps with management areas or other areas within

which neighbouring Aboriginal groups have and exercise rights.

Clearly, decisions regarding land and resource projects on the fee simple lands under these agreements are within the control of the Aboriginal group, subject to the laws and regulations of the Aboriginal group, as well as to any generally applicable environmental assessment or environmental protection laws and regulations. The more difficult and nuanced an issue is the more difficult it is to identify the degree of control exercised by the Aboriginal group on the second and third categories of land identified above. This will be discussed further below in Part II.

#### **Non-Treaty Areas in Canada**

Notwithstanding the historic and modern treaty making efforts, there remain significant portions of Canada where treaties have never been signed. For example, in British Columbia, where there are over 200 First Nations (of slightly more than 600 in all of Canada), the vast majority of Aboriginal groups do not have a treaty in place.<sup>15</sup> In the absence of treaties, the major developments came from judicial decisions regarding Aboriginal rights and title. In the hierarchical world of the courts, there are no judicial pronouncements more important than those that come from the Supreme Court of Canada and so the following overview will focus on the major milestones from that Court and constitutional developments.

#### *The Calder Decision*

In the late 1960’s, Frank Calder, the Nishga Tribal Council and four Indian bands, brought an action against the Attorney-General of British Columbia for a declaration “that the aboriginal title, otherwise known as the Indian title, of the Plaintiffs to their ancient tribal territory... has never been lawfully extinguished”. The claim was based in part on *The Royal Proclamation*

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<sup>15</sup> As discussed above, the major exceptions are (i) small portions of Vancouver Island that are covered by the pre-Confederation Douglas Treaties; (ii) the northeast section of the province, which is covered by post-Confederation Treaty No 8; (iii) the modern-day Nisga’a treaty (2000) and the relatively small number of modern treaties completed to date under the BC Treaty Commission process, including the Tsawwassen First Nation Final Agreement (2009) and Maa-nulth First Nations Final Agreement (2011).

of October 7, 1763. The action was dismissed at trial and the Court of Appeal rejected the appeal.

A seven judge panel of the Supreme Court of Canada heard the appeal and, in a procedurally unusual decision, split 3-3-1.<sup>16</sup>

- Three judges (Hall, Spence and Laskin JJ.) would have allowed the appeal, and rejected as “wholly wrong” the proposition that “after conquest or discovery the native peoples have no rights at all except those subsequently granted or recognized by the conqueror or discoverer.” They found that Aboriginal title continued and it had not been surrendered.
- Three judges (Martland, Judson and Ritchie JJ) voted to dismiss the appeal based on the very terms of the Proclamation and “upon the history of the discovery, settlement and establishment of what is now British Columbia.” Since the area in question did not come under British sovereignty until 1846, the Appellants were not any of the several nations or tribes of Indians who lived under British protection in 1763 and they were outside the scope of the Proclamation.
- The seventh judge (Pigeon J.) refused to decide the substantive issue, instead concluding that the Court had no jurisdiction (in the absence of a fiat of the Lieutenant-Governor of that Province) to make the declaration prayed for, being a claim of title against the Crown in the right of the province of British Columbia.

Given the unusual 3-3-1 split, the resulting decision was inconclusive, but this decision is generally credited with restarting the modern treaty making process in Canada. (The Nisga’a Final Agreement became effective in 2000.)

#### *Section 35 Jurisprudence*

Following the introduction of s. 35(1) of the *Constitution Act, 1982*, the Supreme Court of

Canada addressed its scope in *R. v. Sparrow*, [1990] 1 SCR 1075 [Sparrow]. The Court held that section 35(1) needs to be construed in “a purposive way” and that a generous, liberal interpretation is demanded given that the provision is to affirm Aboriginal rights. Legislation that affects the exercise of aboriginal rights will be valid if it meets the test for justifying an interference with a right recognized and affirmed under s. 35(1).

Following the *Sparrow* decision in 1990, an increasing volume of Aboriginal law litigation throughout the 1990s focused on Aboriginal rights and title—including the content of such rights and how they could be established. These issues made their way to the Supreme Court of Canada in the late 1990s in a series of appeals. Arguably, two of the most important from this time were:

- *R. v. Van der Peet*, [1996] 2 S.C.R. 507.

This appeal, heard along with the companion appeals in *R. v. N.T.C. Smokehouse Ltd.*, [1996] 2 S.C.R. 672, and *R. v. Gladstone*, [1996] 2 S.C.R. 723, addressed the issue left unresolved by the Supreme Court of Canada in its judgment in *R. v. Sparrow*, [1990] 1 S.C.R. 1075, namely: How are the aboriginal rights recognized and affirmed by s. 35(1) of the *Constitution Act, 1982* to be defined? To be an aboriginal right an activity must be an element of a practice, custom or tradition integral to the distinctive culture of the aboriginal group claiming the right. The practices, customs and traditions which constitute aboriginal rights are those which have continuity with the practices, customs and traditions that existed prior to contact with European society.

- *Delgamuukw v. British Columbia*, [1997] 3 S.C.R. 1010 [Delgamuukw].

This appeal addressed the content of Aboriginal title, how it is protected by s. 35 of the *Constitution Act, 1982* and the requirements necessary to prove it. The Court held that Aboriginal title encompasses the right to exclusive use and occupation of the land held pursuant to that title for a variety of purposes,

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<sup>16</sup> *Calder et al. v Attorney-General of British Columbia*, [1973] SCR 313.

which need not be aspects of those aboriginal practices, customs and traditions which are integral to distinctive aboriginal cultures. In order to establish a claim to aboriginal title, the aboriginal group asserting the claim must establish that it occupied the lands in question at the time at which the Crown asserted sovereignty over the land subject to the title.

However, the Court did not identify precisely *where* Aboriginal rights or title existed or precisely define their content. This was left to be defined through either further litigation or settled by treaty negotiations. As discussed above, a number of the Aboriginal groups in the province are currently involved in treaty negotiations with the Crown—while other Aboriginal groups are seeking to establish Aboriginal title and/or rights through the courts. In the meantime, the *precise* location of Aboriginal title in British Columbia and other such areas remains undefined. In the absence of such definition, these Aboriginal groups have asserted Aboriginal rights and title over large tracts of Crown land. Many of these asserted “traditional territories” overlap with neighbouring claims.

Both the further definition of Aboriginal rights and Aboriginal title remain a work in progress:

- In respect of Aboriginal rights, the Supreme Court of Canada has considered a number of specific claims to specific rights. For example, the Court has recently addressed a number of claims to commercial fishing rights.<sup>17</sup>
- In respect of Aboriginal title, the Supreme Court of Canada has had the occasion to elaborate on the issue<sup>18</sup>, and it currently has a very significant case

under reserve that will likely provide an opportunity to further clarify the nature of Aboriginal title.<sup>19</sup>

- The Supreme Court of Canada has also issued a series of decisions on Metis rights.<sup>20</sup>

The key message from Part I is that, in order to begin correctly, it is necessary that all participants (Energy Regulators and parties appearing before them) appreciate and understand the applicable legal context of the Aboriginal groups that may participate in regulatory processes. Energy Regulators, whose jurisdiction is confined by provincial, territorial or federal boundaries, may encounter Aboriginal groups in all three legal contexts. Some groups may have treaty rights (based on historic and/or modern agreements) while others many have asserted or established Aboriginal rights. Understanding the context can help to avoid errors that may arise in applying case law, principles or practices that have been developed or discussed in a different legal context. The proper understanding of the legal context of Aboriginal and treaty rights is important in considering the Crown's duty to consult, which is canvassed in Part II.

## Part II: The Duty to Consult<sup>21</sup>

### The Duty to Consult – Origins and Overview of the Case Law

One of the first observations about the duty to consult is that it is in its origins (and still remains) primarily judge-made law. Unlike many of the issues faced by Energy Regulators (which are grounded in statute, regulations or government policy), the law regarding the Crown's duty to consult is primarily the result

<sup>17</sup> See *Lax Kw'alaams Indian Band v Canada (Attorney General)*, 2011 SCC 56, [2011] 3 SCR 535. See also *Ahousaht Indian Band v Canada (Attorney General)*, 2012 BCCA 404, leave to appeal to the Supreme Court of Canada denied January 30, 2014.

<sup>18</sup> See *Marshall*, *supra* note 5; *R v Bernard*, [2005] 2 SCR 220, 2005 SCC 43.

<sup>19</sup> See the BC Court of Appeal decision in *William v British Columbia*, 2012 BCCA 285 [William]. The Supreme Court of Canada granted leave to appeal and the appeal was heard in November 2013. The decision is under reserve.

<sup>20</sup> *R v Powley*, 2003 SCC 43, [2003] 2 SCR 207; *Manitoba Metis Federation Inc. v Canada (Attorney General)*, 2013 SCC 14; *R v Hirsekorn*, 2013 ABCA 242, application for leave to appeal dismissed *Hirsekorn v the Queen*, 2014 CanLII 2421.

<sup>21</sup> Some portions of Part II and Part III draw upon and develop ideas initially put forward in the article by Chris W. Sanderson, Q.C., K. Bergner and Michelle S. Jones “The Crown's Duty to Consult Aboriginal Peoples: Towards an understanding of the source, purpose and limits of the duty”, (May 2012) 49:1 Alberta Law Review.

of jurisprudence. While consultation policies and (recently) legislation have begun to play a larger role, it is still the jurisprudence that plays the dominant chords.

The duty to consult first received significant judicial attention in the non-treaty areas of Canada—particularly in British Columbia. There were references to Crown consultation in the context of the discussion of Aboriginal rights<sup>22</sup> and Aboriginal title,<sup>23</sup> but the scope and extent of any legal duty remained indeterminate. In the late 1990s and early 2000s, debate raged in the lower courts regarding when, if ever, the Crown had a “duty to consult” in circumstances where Aboriginal rights and title were asserted, but unproven.

This issue was addressed by the Supreme Court of Canada in 2004 when it issued two seminal decisions on the Crown’s duty to consult: *Haida Nation v. British Columbia (Minister of Forests)*, 2004 SCC 73 and *Taku River Tlingit First Nation v. British Columbia (Project Assessment Director)*, 2004 SCC 74. These two cases arose in areas of British Columbia where treaties were never signed historically between the Crown (the federal and/or provincial governments) and First Nations.

From the very beginning, it was clear to the Supreme Court of Canada (and many observers) that the understanding of the duty to consult had only begun. In *Haida*, the Court stated:

“This case is the first of its kind to reach this Court. Our task is the modest one of establishing a general framework for the duty to consult and accommodate, where indicated, before Aboriginal title or rights claims have been decided. As this framework is applied, courts, in the age-old tradition of the Common Law, will be called on to

fill in the details of the duty to consult and accommodate.” (para. 11)

This work of “filling in the details” of duty to consult has been underway ever since—including occasional decisions from the Supreme Court of Canada. Notable milestones include the following:

- In 2005, the Supreme Court of Canada applied this new framework of the Crown’s duty to consult in the context of a historic treaty (Treaty 8 signed in 1899). *Mikisew Cree First Nation v. Canada (Minister of Canadian Heritage)*, 2005 SCC 69.<sup>24</sup>
- In 2010, the Supreme Court of Canada applied the framework in the context of a modern treaty (signed in 1997). *Beckman v. Little Salmon/Carmacks First Nation*, 2010 SCC 53.<sup>25</sup>
- Also in 2010, the Supreme Court of Canada reaffirmed how the framework operates in a non-treaty context—with a particular emphasis on whether past infringements of Aboriginal rights could be a trigger for the duty to consult—and (importantly for the subject of this article) examined the place of government tribunals in consultation and the review of consultation. *Rio Tinto Alcan Inc. and BC Hydro v. Carrier Sekani Tribal Council*, 2010 SCC 43.
- Most recently in 2013, the Supreme Court of Canada considered the question of to whom the Crown owes a duty to consult—including whether individuals can assert a duty to consult or invoke treaty rights—and the proper procedure for raising allegations of inadequate consultation. *Behn v. Moulton*

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<sup>22</sup> For example, in the 1990 decision *Sparrow*, the Court’s discussion of “justification” for infringement of Aboriginal rights identified some of the questions to be addressed, including whether the aboriginal group in question has been consulted with respect to the measures being implemented.

<sup>23</sup> For example, in the 1997 decision *Delgamuukw*, the Court’s discussion of “justification” for infringement of Aboriginal title included the following statements: “There is always a duty of consultation. Whether the Aboriginal group has been consulted is relevant to determining whether the infringement of Aboriginal title is justified, in the same way that the Crown’s failure to consult an aboriginal group with respect to the terms by which reserve land is leased may breach its fiduciary duty at Common Law.” (at para 168.)

<sup>24</sup> *Mikisew Cree First Nation v. Canada (Minister of Canadian Heritage)*, 2005 SCC 69 (in respect of Treaty 8 signed in 1899) [*Mikisew*].

<sup>25</sup> *Beckman*, *supra* note 9 (in respect of a treaty signed in 1997).

*Contracting Ltd*, 2013 SCC 26.

The following discussion will review the major aspects of this case law—focusing on those issues of key interest to Energy Regulators.

### **The Framework for the Duty to Consult in Non-Treaty Areas - Haida**

In *Haida*, the Court held that the government has a duty to consult with Aboriginal peoples that is grounded in the principle of the “honour of the Crown.” Pending settlement of Aboriginal claims, the Supreme Court of Canada determined that the Crown’s duty “arises when the Crown has knowledge, real or constructive of the potential existence of the Aboriginal right or title and contemplates conduct that might adversely affect it.”<sup>26</sup>

The scope and content of the duty to consult and accommodate varies with the circumstances. In general terms, the scope of the duty is proportionate to a preliminary assessment of two variables: the strength of the case supporting the existence of the right or title, and the seriousness of the potentially adverse effect upon the right or title claimed.<sup>27</sup> This produces a “spectrum” of consultation. In cases where the claim to title is weak, the Aboriginal right limited, or the potential for infringement minor, the only duty may be to give notice, disclose information and discuss any issues raised in response to the notice.<sup>28</sup> At the other end of the spectrum, where a strong *prima facie* case for the claim is established, the right and potential infringement is of high significance to the Aboriginal peoples, and the risk of non-compensable damage is high, “deep consultation”, aimed at finding a satisfactory interim solution, may be required.<sup>29</sup> While the precise requirements will vary with the circumstances, the consultation required in these cases may entail the opportunity to

make submissions for consideration, formal participation in the decision-making process, and provision of written reasons to show that Aboriginal concerns were considered and to reveal the impact they had on the decision. This list is neither exhaustive nor mandatory in every case. Other cases fall between these two extremes. Each case must be approached individually. Each case must also be approached flexibly, since the level of consultation required may change as the process goes on and new information comes to light. The Supreme Court of Canada has directed that the “controlling question” in all situations is “what is required to maintain the honour of the Crown and to effect reconciliation between the Crown and the Aboriginal peoples with respect to the interests at stake.”<sup>30</sup>

The effect of good faith consultation may be to reveal a “duty to accommodate”. Where a strong *prima facie* exists for the claim, and the consequences of government’s proposed decision may affect it in a significant way, addressing the Aboriginal concerns may require “taking steps to avoid irreparable harm or to minimize the effects of infringement, pending final resolution of the underlying claim.”<sup>31</sup>

The right to be consulted about proposed activities on Crown land does not provide Aboriginal groups with a “veto.”<sup>32</sup> There is no duty to agree.

Third parties, such as private oil and gas, mining or forestry companies, do not have a legal duty to consult. However, that does not mean they have no role to play:

“The Crown alone remains legally responsible for the consequences of its actions and interactions with third parties, that affect Aboriginal interests. The Crown may

<sup>26</sup> *Haida Nation v British Columbia (Minister of Forests)*, 2004 SCC 73 at para 35 [*Haida*]. In *Rio Tinto*, *supra* note 2 at para 31, the Court confirmed that test for when the duty to consult arises (in non-treaty areas) can be broken down into three elements: (1) the Crown’s knowledge, actual or constructive, of a potential Aboriginal claim or right; (2) contemplated Crown conduct; and (3) the potential that the contemplated conduct may adversely affect an Aboriginal claim or right.

<sup>27</sup> *Ibid* at para 39.

<sup>28</sup> *Ibid* at para 43.

<sup>29</sup> *Ibid* at para 44.

<sup>30</sup> *Ibid* at para 45.

<sup>31</sup> *Ibid* at para 47.

<sup>32</sup> *Ibid* at para 48.

delegate procedural aspects of consultation to industry proponents seeking a particular development; this is not infrequently done in environmental assessments.” [Emphasis added.]<sup>33</sup>

The permissible scope and extent of delegation of “procedural aspects” of consultation (and how such delegation is carried out) is a source of ongoing debate. In practice, this has frequently meant that the lion’s share of the consultation obligation falls to industrial proponents.

As further discussed in Part III, this observation is especially important in the context of the role of the Energy Regulator—where the Applicant is most often an “industry proponent seeking a particular development.” The ability of the Crown to delegate “procedural aspects” of consultation to industry proponents seeking a particular development is important in the context of determining the role of Energy Regulators—who may have a role in assessing the adequacy of consultation carried out by a (private) proponent, but who may or may not have a role in assessing the adequacy of Crown consultation in respect of the same project.

#### *The Framework Contemplates an Administrative Process*

The decision at issue in *Haida* was not the product of an administrative tribunal (much less a quasi-judicial Energy Regulator). Nevertheless, the Court provided some commentary on how an administrative regime may be an appropriate forum for addressing the Crown’s duty to consult:

The government may wish to adopt dispute resolution procedures like mediation or administrative regimes with impartial decision-makers in complex or difficult cases.<sup>34</sup>

The Court went on to note that the choice of how to structure such a process rested with the

government:

It is open to governments to set up regulatory schemes to address the procedural requirements appropriate to different problems at different stages, thereby strengthening the reconciliation process and reducing recourse to the Courts<sup>35</sup>.

While noting that “[t]o date, the Province has established no process for this purpose”, the Court nevertheless outlined what standard of review would apply to any administrative process that might be set up for such a purpose.<sup>36</sup> The Court concluded this discussion with another reference that suggests the parallels between this area of Aboriginal law and administrative/regulatory law: “The focus...is not on the outcome, but on the process of consultation and accommodation.”<sup>37</sup>

This discussion would be picked up and elaborated in later cases (notably *Carrier Sekani*). However, first it is necessary to examine *Haida*’s companion case—*Taku River*—for what it can teach regarding the role of administrative processes and decision-making.

#### *The Framework Applied to a (non-quasi-judicial) Administrative Process - Taku River*

The Supreme Court’s decision in *Taku River Tlingit First Nation v. British Columbia (Project Assessment Director)*, 2004 SCC 74 was released together with the *Haida* decision. Unlike the governmental decision at issue in *Haida*, the decision-making process reviewed in *Taku* followed a recommendation resulting from an environmental assessment process unfolding under a legislatively established administrative scheme—although not one involving a quasi-judicial regulatory tribunal hearing in the manner common to Energy Regulators. The project at issue involved reopening an old mine site and developing an access road. While the application was being considered, it became subject to the then-newly passed the

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<sup>33</sup> *Ibid* at para 53.

<sup>34</sup> *Ibid* at para 44.

<sup>35</sup> *Ibid* at para 51.

<sup>36</sup> *Ibid* at para 60-63.

<sup>37</sup> *Ibid* at para 63.

*Environmental Assessment Act*, R.S.B.C. 1996, c. 119.<sup>38</sup> One of the purposes of the *Environmental Assessment Act* (as it read at the time), set out in former section 2(e), was “to provide for participation, in an assessment under this Act, by... First Nations...”. The Taku River Tlingit were invited and agreed to participate in the “project committee” and various sub-committees. Ultimately, the majority of the project committee members prepared a written recommendations report to refer the application for a project approval certificate to the Ministers for decision. The First Nation disagreed with the recommendations contained in the report and prepared its own report stating their concerns with the process and the proposal. The Ministers approved the proposed project and a Project Approval Certificate was issued, subject to detailed terms and conditions.

The Supreme Court of Canada found that the province was under a duty to consult with the Taku River Tlingit in making the decision to reopen the mine.<sup>39</sup> The Court found that acceptance of the Taku River Tlingit’s title claim for negotiation under the B.C. Treaty Commission Process established a *prima facie* case in support of its Aboriginal rights and title and that the potential for negative impacts on the Taku River Tlingit’s claims was high.<sup>40</sup> The Court concluded that the Taku River Tlingit were “entitled to something significantly deeper than minimal consultation under the circumstances, and to a level of responsiveness to its concerns that can be characterized as accommodation.”<sup>41</sup>

However, after reviewing the process that had unfolded through the environmental assessment, the Court concluded that the consultation provided by the province was adequate.<sup>42</sup> Notably, the Court confirmed that the province was not required to establish a separate consultation process to address Aboriginal concerns, but that this could take

place within the existing administrative process.

“The province was not required to develop special consultation measures to address TRTFN’s [Taku River Tlingit First Nation’s] concerns, outside of the process provided for by the *Environmental Assessment Act*, which specifically set out a scheme that required consultation with affected Aboriginal peoples.”<sup>43</sup>

In reviewing the extensive participation of the Taku River Tlingit in multiple stages of the review, the Court found that, by the time the assessment was concluded, the concerns of the First Nation were well understood and had been meaningfully discussed. Thus, the Crown “had thoroughly fulfilled its duty to consult.”<sup>44</sup>

The Court noted that further, more detailed consultations would occur through the project permitting phase, as well, allowing the Crown to continue to discharge its obligation to consult and, where necessary, accommodate Aboriginal concerns.

The Project Committee concluded that some outstanding TRTFN concerns could be more effectively considered at the permit stage or at the broader stage of treaty negotiations or land use strategy planning. ... The Project Committee, and by extension the Ministers, therefore clearly addressed the issue of what accommodation of the TRTFN’s concerns was warranted at this stage of the project, and what other venues would also be appropriate for the TRTFN’s continued input. It is expected that, throughout the permitting, approval and licensing process, as well as in the development of a land use strategy, the Crown will continue to fulfill its honourable duty to consult and, if indicated, accommodate the TRTFN.”<sup>45</sup>

It is clear from the discussion in *Haida* and

<sup>38</sup> The 1996 BC *Environmental Assessment Act* was subsequently amended, SBC 2002, c 43.

<sup>39</sup> *Taku River Tlingit First Nation v British Columbia (Project Assessment Director)*, 2004 SCC 74 at paras 23-28 [*Taku*].

<sup>40</sup> *Ibid* at para 30.

<sup>41</sup> *Ibid* at para 32.

<sup>42</sup> *Ibid* at para 39.

<sup>43</sup> *Ibid* at para 40.

<sup>44</sup> *Ibid* at para 41.

<sup>45</sup> *Ibid* at para 46.

*Taku* that the duty consult framework included, from the very beginning, contemplation of an important role for administrative decision-making within the existing environmental and regulatory review process—even if such processes did not address all outstanding issues. Further clarification of the role of Energy Regulators would be some years in coming. However, the broad outlines of the approach that emerged were visible in the Court's early decisions.

### **The Duty to Consult in Historic Treaty Areas - Mikisew**

Following the establishment of the framework for the duty to consult in 2004, one of the first questions to arise was how the duty to consult applied in the context of treaty rights. In 2005, the Court considered the duty to consult in the context of a historic treaty—Treaty 8 concluded in 1899.

The case involved a challenge to Ministerial approval of a proposal to re-establish a winter road through Wood Buffalo National Park. The Mikisew Cree First Nation, a Treaty 8 signatory, objected to the proposed road on the grounds that it would infringe on their hunting and trapping rights under Treaty 8. Parks Canada had provided a standard information package about the road to the First Nation, and the First Nation was invited to informational open houses along with the general public. Parks Canada did not consult directly with the First Nation about the road, or about means of mitigating impacts of the road on treaty rights, until after important routing decisions had been made. The First Nation challenged the decision of the Minister of Canadian Heritage, the Minister responsible for Parks Canada, to authorize the construction of the road on the grounds that the Minister had not adequately consulted the First Nation about the road.

Treaty Number 8 contains the following clause (which is included in similar terms in most of

the other numbered treaties)<sup>46</sup>:

“And Her Majesty the Queen HEREBY AGREES with the said Indians that they shall have right to pursue their usual vocations of hunting, trapping and fishing throughout the tract surrendered as heretofore described, subject to such regulations as may from time to time be made by the Government of the country, acting under the authority of Her Majesty, and saving and excepting such tracts as may be required or taken up from time to time for settlement, mining, lumbering, trading or other purposes.” [Emphasis added.]

The Court confirmed that Treaty 8 contemplated that land would be “taken up”, but found that the treaty did not specify the process by which such taking up would occur. The Court employed the duty to consult to fill this procedural gap:

Both the historical context and the inevitable tensions underlying implementation of Treaty 8 demand a *process* by which lands may be transferred from the one category (where the First Nations retain rights to hunt, fish and trap) to the other category (where they do not). The content of the process is dictated by the duty of the Crown to act honourably.<sup>47</sup>

The Court held that Treaty 8 confers on the Mikisew Cree substantive rights (hunting, trapping, and fishing) along with the procedural right to be consulted about infringements of the substantive rights. The Supreme Court found that, because the taking up adversely affected the First Nation's treaty right to hunt and trap, Parks Canada was required to consult with the Mikisew Cree before making its decision.

The Court noted that a similar sliding scale of consultation obligations applied in a treaty context as in a non-treaty context. However, in place of the “strength of claim” (for an asserted

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<sup>46</sup> Some of the numbered treaties contain slightly different language, although the significance of the difference is still not a resolved question. The Supreme Court of Canada has granted leave to appeal in respect of Treaty 3. See: *Keewatin v Ontario (Natural Resources)*, 2013 ONCA 158; leave to appeal granted *Keewatin v Minister of Natural Resources*, 2013 CanLII 59883.

<sup>47</sup> *Mikisew*, *supra* note 23 para 33.

but unproven right) the Court substituted the “specificity of the treaty promise”. The second variable (adverse effect) remained substantially unchanged, with the Court stating that “adverse impact is a matter of degree, as is the extent of the Crown’s duty.”

The historic treaty clearly altered how the duty to consult applied. The Court held that, while the winter road would affect Mikisew Cree treaty hunting and trapping rights, this was a fairly minor road that was built on lands “surrendered” by the Mikisew Cree when they signed Treaty 8. As a result, the lower end of the consultation spectrum was engaged. This meant Parks Canada should have provided notice to the Mikisew Cree, and should have engaged them directly to solicit their views and to attempt to minimize adverse impacts on their rights. As Parks Canada had unilaterally determined important matters like road alignment before meeting with the Mikisew Cree, the Court held that the Crown’s duty to consult had not been adequately discharged.

#### **The Duty to Consult in Modern Treaty Areas - Little Salmon**

The 2004/2005 decisions outlined how the duty to consult applied in non-treaty and historic treaty areas. In 2010, the Supreme Court of Canada released its decision in *Beckman v. Little Salmon/Carmacks First Nation* which addressed how the Crown’s duty to consult Aboriginal groups about Crown decisions applies in the context of modern land claims agreements.

The case arose in respect of the 1997 *Little Salmon/Carmacks First Nation Final Agreement* (the “Final Agreement”), which the Little Salmon/Carmacks First Nation entered into with the Yukon and Canadian governments.<sup>48</sup> In 2001, the government received an application for an agricultural land grant of some 65 hectares of Yukon Crown Land within the traditional territory covered by the Final Agreement. The

Final Agreement provided that members of Little Salmon/Carmacks have the right to access Crown land in their traditional territory for subsistence harvesting except where the land in question is subject to an agreement for sale as was sought in the Application. The Application was reviewed in a series of administrative review processes including:

- A “pre-screening” by the Agriculture Branch and the Lands Branch as well as the Land Claims and Implementation Secretariat;
- A more in-depth technical review by the Agriculture Land Application Review Committee (“ALARC”) – a body that predated and was completely independent from the treaty. ALARC recommended that the Applicant reconfigure his parcel for reasons related to the suitability of the soil and unspecified environmental, wildlife, and trapping concerns. The Applicant complied.
- A further level of review by the Land Application Review Committee (“LARC”), a committee composed of representatives of the federal, territorial, provincial government agencies as well as First Nations including the Little Salmon/Carmacks. LARC also predated and was completely independent from the treaty.

By way of letter to LARC, Little Salmon/Carmacks expressed concerns regarding the Application. However, no representative of Little Salmon/Carmacks attended the meeting and there was no request for an adjournment. The concerns raised in the letter were considered by LARC, but LARC ultimately approved the Application. The Director of Agriculture Branch of the Yukon government (the “Director”) considered and confirmed LARC’s approval.

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<sup>48</sup> Under the Final Agreement, Little Salmon/Carmacks received certain benefits, including title to 2,589 square kilometres of land, financial compensation in excess of \$34 million, potential for royalty sharing, economic development measures and rights to harvest fish, wildlife, and forest resources. In addition, Little Salmon/Carmacks, along with other Yukon First Nations, was entitled to appoint members to co-management boards dealing with fish and wildlife management, development assessment, land use planning and other renewable resources management issues in their traditional territories.

The Little Salmon/Carmacks sought judicial review of the Director's decision to approve the Application. There were two major issues: 1. Was the Yukon government required to consult with and, if necessary, accommodate Little Salmon/Carmacks beyond what was expressly required by the Final Agreement? 2. If so, what scope of consultation was required and had the government's duty been discharged?

The Supreme Court of Canada issued two judgments: one supported by seven judges, and another supported by two judges. While the two judgements are technically "concurring" opinions (as they agreed on the disposition of the particular case), they represent fundamentally different views on how the duty to consult should apply in the context of modern treaties.

#### *The Majority Decision*

Binnie J. writing for the seven-judge majority emphasised that the Final Agreement reflects "a balance of interests" and that the Yukon treaties are intended, in part, to replace expensive and time-consuming *ad hoc* procedures with mutually agreed upon legal mechanisms that are efficient but fair.

On the first issue (whether the duty to consult applied), the majority decision concluded that "duty to consult is derived from the honour of the Crown which applies independently of the expressed or implied intention of the parties." The Majority stated:

...the procedural gap created by the failure to implement Chapter 12 had to be addressed, and the First Nation, in my view, was quite correct in calling in aid the duty of consultation in putting together an appropriate procedural framework.<sup>49</sup>

The majority stated: "Consultation can be shaped by agreement of the parties, but the

Crown cannot contract out of its duty of honourable dealing with Aboriginal people."<sup>50</sup>

When a modern treaty has been concluded, the first step is to look at its provisions and try to determine the parties' respective obligations, and whether there is some form of consultation provided for in the treaty itself. If a process of consultation has been established in the treaty, the scope of the duty to consult will be shaped by its provisions.

The majority emphasized that "the honour of the Crown may not *always* require consultation. The parties may, in their treaty, negotiate a different mechanism which, nevertheless, in the result, upholds the honour of the Crown."<sup>51</sup> However, in this case, the majority concluded that the Final Agreement did not exclude the duty to consult and, if appropriate, accommodate.

On the second issue (what scope of consultation was required and whether the duty to consult had been fulfilled), the majority reviewed the negotiated definition of Consultation contained in the Final Agreement and found it to be a reasonable statement of the content of consultation "at the lower end of the spectrum." The majority concluded that "consultation was made available and *did* take place through the LARC process."<sup>52</sup> The majority confirmed that "participation in a forum created for other purposes may nevertheless satisfy the duty to consult if *in substance* an appropriate level of consultation is provided."<sup>53</sup> On the facts, the majority concluded that the requirements of the duty to consult were met.

The First Nation had argued that the legal requirement was not only procedural consultation but "substantive accommodation." In this case, in its view, accommodation must inevitably lead to rejection of the Application. The majority firmly rejected this argument and concluded that "nothing in the treaty itself or

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<sup>49</sup> *Little Salmon*, *supra* note 9 at para 38.

<sup>50</sup> *Ibid* at para 61.

<sup>51</sup> *Ibid* at para 71.

<sup>52</sup> *Ibid* at para 39.

<sup>53</sup> *Ibid* at para 39.

in the surrounding circumstances gave rise to a requirement of accommodation.”<sup>54</sup>

#### *The Minority Decision*

Deschamps J. writing for a two-judge minority agreed with the result, but her reasons for doing so were very different. The minority emphasized that the Final Agreement was the product of extensive negotiations between the parties.

To add a further duty to consult to these provisions would be to defeat the very purpose of negotiating a treaty. Such an approach would be a step backward that would undermine both the parties’ mutual undertakings and the objective of reconciliation through negotiation. This would jeopardize the negotiation processes currently under way across the country. The minority expressed the concern that “the courts must ensure that this duty is not distorted and invoked in a way that compromises rather than fostering negotiation.”

The fundamental difference between the majority and the minority was that the minority disagreed that any “procedural gap” existed in this case, and disagreed with superimposing the Common Law duty to consult on the treaty.

Deschamps J. (for the minority) agreed in principle that *if* there was a procedural gap in a modern treaty then the Common Law duty to consult *could* be applied to fill that gap. However, the minority examined the treaty’s transitional provisions and concluded that no such gap could be found in the treaty in question.<sup>55</sup>

Deschamps J. would appear to draw a distinction between the duty to consult in the context of asserted but unproven claims and the duty to consult in the context of a treaty—going so far as to state that it would be

“misleading” to consider the duty to consult to be the same duty in both contexts:

Moreover, where, as in *Mikisew*, the Common Law duty to consult must be discharged to remedy a gap in the treaty, the duty undergoes a transformation. Where there is a treaty, the function of the Common Law duty to consult is so different from that of the duty to consult in issue in *Haida Nation* and *Taku River* that it would be misleading to consider these two duties to be one and the same. It is true that both of them are constitutional duties based on the principle of the honour of the Crown that applies to relations between the Crown and Aboriginal peoples whose constitutional — Aboriginal or treaty — rights are at stake. However, it is important to make a clear distinction between, on the one hand, the Crown’s duty to consult before taking actions or making decisions that might infringe Aboriginal rights and, on the other hand, the minimum duty to consult the Aboriginal party that necessarily applies to the Crown with regard to its exercise of rights granted to it by the Aboriginal party in a treaty.<sup>56</sup>

The minority looked to the provisions of the Final Agreement itself—in particular the assessment process provided for in the Final Agreement that applied to the Application—and concluded that there are provisions in the Final Agreement that govern the very issue of whether the Crown is required to consult the First Nation before exercising its right to transfer land.

The requirements of the processes in question included not only consultation with the First Nation concerned, but also its participation in the assessment of the project. Any such participation would involve a more extensive consultation than would be required by the

<sup>54</sup> Nigel Bankes has criticized the majority’s decision: “In my view the content of the duty to consult articulated by the Court in this case is no greater than that which would be provided by the application of standard principles of administrative law. This impoverished view of the duty to consult is hardly likely to contribute to the constitutional goal of inter-societal reconciliation.” See “Little Salmon and the juridical nature of the duty to consult and accommodate” posted on December 10, 2010: <<http://ablawg.ca/2010/12/10/little-salmon-and-the-juridical-nature-of-the-duty-to-consult-and-accommodate/>>.

<sup>55</sup> *Little Salmon*, *supra* note 9 at para 124, Deschamps J.

<sup>56</sup> *Ibid* at para 19.

Common Law duty in that regard. Therefore, nothing in this case can justify resorting to a duty other than the one provided for in the Final Agreement.

The minority concluded that the process that led to the decision on the Application was consistent with the provisions of the Final Agreement and that there was no legal basis for finding that the Crown breached its duty to consult.

#### *Implications of the Decision*

The *Little Salmon/Carmacks* decision, along with the Supreme Court of Canada's decision in *Moses*<sup>57</sup> were the Supreme Court's first opportunities to apply jurisprudence on the Crown's duty to consult in the context of modern treaties and land claim agreements.

For many of the existing modern land claims agreements—particularly the earlier agreements and those in the Yukon, Northwest Territories and Nunavut (discussed above)—the result of the majority decision is that there will be continued uncertainty as to whether government is under a duty, and the extent of that duty, to consult Aboriginal groups when making land and resource management decisions. While the *Little Salmon/Carmacks* decision indicates that governments can, through negotiation of treaties, narrow and define the extent of the duty to consult, the fact remains that, where this has not been done in existing treaties, the Common Law duty to consult will continue to apply and will continue to be a potential source of disagreement between governments and Aboriginal treaty signatories as to whether the duty is triggered and what it requires governments to do.

Some recent modern treaties such the Tsawwassen Final Agreement in British Columbia have included provisions specifying that the treaties contain an “exhaustive list of the consultation obligations of Canada and British Columbia.”<sup>58</sup> The *Little Salmon/Carmacks* decision recognizes that courts should defer to the intentions of the parties where clearly expressed in the treaty and

where not inconsistent with the honour of the Crown. It can be expected that future treaties will continue to address with greater specificity how the parties intend the Crown's duty to consult will apply in those treaties.

In respect of fulfilling the duty to consult, it is notable that all nine judges of the Supreme Court of Canada was unanimous in concluding that the steps undertaken by the Government of the Yukon were adequate to fulfill the Crown's obligation. It is clear that allowing First Nations to participate in a forum created for other purposes may nevertheless satisfy the duty to consult if in substance an appropriate level of consultation is provided. On the facts of this case—where the First Nation failed to attend the meeting, submitted its concern by letter and those concerns were considered by the decision-maker—the Court concluded that the requirements of the duty to consult were met.

#### **Special Issues – Past Wrongs**

In addition to clarifying how the duty to consult applies differently in different legal contexts (non-treaty, historic treaty and modern treaty areas), the jurisprudence as also wrestled with a number of related scoping issues. Two will be canvassed here given their importance for Energy Regulators: (i) the issue of past infringements; and (ii) the issue of to whom the duty to consult is owed.

In *Rio Tinto* the Court commented on the significance of past grievances or historical infringements in the context of what is required to establish the possibility that the Crown conduct may affect the Aboriginal claim or right:

“The [First Nation] must show a causal relationship between the proposed government conduct or decision and a potential for adverse impacts on pending Aboriginal claims or rights. Past wrongs, including previous breaches of the duty to consult, do not suffice. ...

An underlying or continuing breach, while

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<sup>57</sup> *Quebec (Attorney General) v Moses*, 2010 SCC 17.

<sup>58</sup> See for example articles 45 and 46 of the Tsawwassen First Nation Final Agreement, December 8, 2006.

remediable in other ways, is not an adverse impact for the purposes of determining whether a particular government decision gives rise to a duty to consult. ...

The question is whether there is a claim or right that potentially may be adversely impacted by the *current* government conduct or decision in question. Prior and continuing breaches, including prior failures to consult, will only trigger a duty to consult if the present decision has the potential of causing a novel adverse impact on a present claim or existing right.”<sup>59</sup>

This clarification of the law regarding the duty to consult has significantly sharpened the focus of inquiry in front of Energy Regulators. Prior to this decision, significant debate took place in regulatory hearings regarding whether the scope of the duty to consult required consultation in respect of pre-existing facilities that we, in some manner, related to the subject matter of the application in front of the Energy Regulator. Two examples can be seen in proceeding before the British Columbia Utilities Commission:

- In proceedings in respect of B.C. Transmission Corporation’s (BCUC) Interior to Lower Mainland (ILM) transmission line, a primary issue during consultation and in the First Nation Interveners’ evidence and submissions before the Commission was the assertion that BCTC/BC Hydro failed to consult on transmission lines, rights-of-way, and other assets associated with lines built in the 1960s and 1970s (the “Existing Assets”). The historical infringement of

asserted Aboriginal rights permeated the discussions between BCTC/BC Hydro and First Nations. However, following the release of the Court’s decision in *Rio Tinto*, the First Nation Interveners withdrew their submissions on Existing Assets.<sup>60</sup>

- The issue also arose in proceedings regarding BC Hydro’s (a Crown agent) proposal to acquire from Teck Metals Ltd. an undivided one-third interest in the Waneta Dam and associated assets. The Waneta Dam is an existing hydro-electric facility that was constructed in the 1950s and has operated ever since. BC Hydro required the approval of the BC Utilities Commission, which was to determine whether the acquisition was in the public interest. In its decision dated March 12, 2010, the BCUC accepted that (i) BC Hydro had a duty to consult; and (ii) the BCUC had to consider the adequacy of that consultation. However, the BCUC rejected the First Nations’ position and BC Hydro was required to consult and accommodate in respect of past infringements and grievances.<sup>61</sup> The three First Nation groups all sought leave to appeal the decision of the Commission to the B.C. Court of Appeal on the grounds, *inter alia*, that the Commission erred in its treatment of the issue of historical infringements. These leave applications were pending (and give a sense of the issues that were pending) at the time the Supreme Court of Canada’s decision in the *Rio Tinto* was released. Following the Supreme

<sup>59</sup> *Rio Tinto*, *supra* note 2 at paras 45, 48-49.

<sup>60</sup> British Columbia Transmission Corporation (BCTC), Reconsideration of the Interior to Lower Mainland (ILM) Transmission Project, Decision, February 3, 2011. This proceeding was a “reconsideration” of an earlier (5 August 2008) decision of the British Columbia Utilities Commission granted a Certificate of Public Convenience and Necessity (CPCN) to the BCTC for the ILM Project. During that Proceeding, the Commission decided that it need not consider the adequacy of First Nations consultation and accommodation efforts on the ILM Project. The decision was appealed and on February 18, 2009 the Court of Appeal issued its decision in *Kwikwetlem First Nation v British Columbia (Utilities Commission)* 2009 BCCA 68 (issued at the same time as the BC Court of Appeal decision in *Carrier Sekani*, which was further appealed to the Supreme Court of Canada). In *Kwikwetlem*, the Court suspended the CPCN and directed the Commission to reconsider First Nations consultation and to determine whether the Crown’s duty to consult and accommodate First Nations had been met up to August 5, 2008, the date the CPCN was granted. See also: *Upper Nicola Indian Band v British Columbia (Environment)*, 2011 BCSC 388, which addressed a challenge to the Environmental Assessment Certificate for the ILM Project.

<sup>61</sup> BCUC Order G-12-10, Reasons for Decision at 28. See online: BCUC <[http://www.bcuc.com/Documents/Orders/2010/DOC\\_24485\\_G-12-10\\_BCH\\_Waneta-Decision.pdf](http://www.bcuc.com/Documents/Orders/2010/DOC_24485_G-12-10_BCH_Waneta-Decision.pdf)>. On August 5, 2010, the BCUC dismissed an application for reconsideration. BCUC G-126-10. See online: BCUC <<http://www.bcuc.com/Documents/>

Court's decision, all three leave to appeal applications were abandoned.

Following the *Rio Tinto* decision, it is clear that the focus of Energy Regulators is on the project and application that is before them—the analysis is confined to the adverse impacts flowing from the current decision, not to larger adverse impacts of the project of which it is a part. Subsequent court decisions<sup>62</sup> have elaborated or clarified this principle, but not altered it.

### **Special Issues – To Whom is the Duty to Consult Owed?**

Uncertainty regarding the identity of the proper Aboriginal group to be consulted can arise in both a non-treaty or treaty context.

In the May 2013 decision in *Behn v Moulton Contracting Ltd.*, 2013 SCC 26, the Supreme Court of Canada considered the questions of to whom a duty to consult is owed and the proper procedure for bringing a challenge to the adequacy of consultation. The Behns were individual members of the Fort Nelson First Nation. No party brought any legal challenge to the validity of certain forestry authorizations issued to Moulton Contracting Ltd. However, when Moulton attempted to access one of the sites, the Behns erected a camp that, in effect, blocked the company's access to the logging sites. Moulton commenced a court action. As a defence to that action, the Behns argued that the Authorizations were void because they were issued in breach of the Crown's duty to consult and because they violated the Behns' hunting and trapping rights under Treaty No. 8.

The first addressed by the Court was whether the Behns, as individual members of an Aboriginal community, can assert a breach of the duty to consult? The Court confirmed that the

duty to consult exists to protect the collective rights of Aboriginal peoples and is owed to the Aboriginal group that holds them. While an Aboriginal group can authorize an individual or an organization to represent it for the purpose of asserting its Aboriginal or treaty rights, no such authorization was given in this case.

Many Energy Regulators, other Crown decision-makers and project proponents have struggled in attempting to discern “who speaks for the Nation” in a consultation process. Many observers had hoped that this decision would provide greater certainty regarding to whom the Crown owes a duty to consult. The Court's conclusion that the duty “is owed to the Aboriginal group that holds the s. 35 rights, which are collective in nature” provides some clarification.<sup>63</sup> However, there remains some legal uncertainty around identifying the Aboriginal group that holds s. 35 rights.

The identity of the proper rights- holder is also a subject that has generated extensive litigation. For example, in *William v. British Columbia*, 2012 BCCA 285, the BC Court of Appeal recognized that “[w]here there is no body with authority to speak for the collective (or worse, where there are competing bodies contending that they have such authority), consultation may be stymied.”<sup>64</sup> However, in the end, the Court of Appeal agreed with the trial judge's conclusion “that the definition of the proper rights holder is a matter to be determined primarily from the viewpoint of the Aboriginal collective itself.”<sup>65</sup> The Supreme Court of Canada heard an appeal from this case in November 2013, and a decision is pending. Accordingly, both legally and factually, there remains residual uncertainty regarding how to identify—in the words of the Behns case—“the Aboriginal group that holds the s. 35 rights” to whom a consultation duty is owed.

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Decisions/2010/DOC\_25967\_Sinixt-Nation\_BCH-Waneta-Reconsideration-Decision-Web.pdf>. Full disclosure: Lawson Lundell represented BC Hydro in the BCUC proceedings and related appeals.

<sup>62</sup> See for example: *Upper Nicola Indian Band v British Columbia (Environment)*, *supra* note 60; *West Moberly First Nations v British Columbia (Chief Inspector of Mines)*, 2011 BCCA 247, leave to appeal denied *Her Majesty the Queen v West Moberly First Nations*, 2012 CanLII 8361; and *Louis v British Columbia (Minister of Energy, Mines, and Petroleum Resources)*, 2013 BCCA 412, leave to appeal to the Supreme Court of Canada denied 2014 CanLII 8257.

<sup>63</sup> *Behn v Moulton Contracting Ltd.*, 2013 SCC 26, at para 30 [*Behn*]

<sup>64</sup> *William*, *supra* note 19 at para 142.

<sup>65</sup> *Ibid* at para 149.

The Court in *Behn* also commented a related issue—whether treaty rights be invoked by individual members of an Aboriginal community? The Court noted that certain Aboriginal and treaty rights may have both collective and individual aspects, and it may well be that in appropriate circumstances, individual members can assert them. However, the Court found it unnecessary to make any “definitive pronouncement” in this regard in the circumstances of this case. The Court’s reluctance to fully address this issue is somewhat disappointing (although understandable) and leaves unanswered (for now) the question of what might be “appropriate circumstances” in which an individual may assert Aboriginal and treaty rights (and whether such circumstances may further require consultation with such individuals). The Court had previously sent signals that individuals were not necessary parties to consultation. In *Little Salmon*, the Court had considered the position of an individual trapper and concluded that the trappers’ entitlement “was a derivative benefit based on the collective interest of the First Nation of which he was a member” and that “he was not, as an individual, a necessary party to the consultation.”<sup>66</sup> The Court’s more open-ended discussion in *Behn* ensures that further litigation on this point is all but inevitable.

## Part II Conclusion

In summary, while many important questions have been answered and many “details” have been filled in on the Crown’s duty to consult and accommodate, many equally large and important questions remain to be resolved. Such further clarity will likely only come—“in the age-old tradition of the Common Law”—in small, incremental steps. While it remains to be seen whether the next ten years of jurisprudence will be as dramatic as the last ten years, there remain an ample number of significant questions still awaiting a definitive pronouncement.

The next Part will address the role of the Energy Regulator in respect of the Crown’s duty to consult. The reach of the regulator is determined and confined by the government (federal or provincial) that created it and thus the jurisdiction of many Energy Regulators is limited or differentiated by provincial/territorial political boundaries. However, as we have discussed in Parts 1 and 2, the various legal contexts applicable to Aboriginal groups (historic treaty, modern treaty or non-treaty) are not confined or limited to provincial or territorial boundaries. A single province may include (and thus a single Energy Regulator may encounter) Aboriginal groups with a historic treaty, modern treaty or no treaty.

## Part III – The Role of the Energy Regulator in Respect of the Crown’s Duty to Consult<sup>67</sup>

The key argument in this Part is that there is no universally applicable answer to the question: What is the role of the Energy Regulator? The answer will depend on the statutory mandate given to the Energy Regulator in the context of the application being considered. As discussed below, some guidance may be had from examining how the regulatory process fits into the overall decision-making process. In addition, the role of the Energy Regulator may differ depending on the nature of the Applicant appearing before it—in particular whether the Applicant is a Crown agent or a private party. This Part will first outline the general principles and then look at three case studies to consider how these principles apply in the context of a number of Canadian Energy Regulators.

### The Role of the Energy Regulator – General Principles

In *Rio Tinto Alcan*, the Court directly addressed the legal principles underlying the role of an Energy Regulator in relation to the Crown’s

<sup>66</sup> *Beckman*, *supra* note 9 at para 35.

<sup>67</sup> At various times during the last several years, I have had the profound privilege of having had several discussions with David Mullan regarding the Crown’s duty to consult and the role of Energy Regulators. He has been generous in sharing his encyclopedic knowledge of administrative law and his enthusiasm for and keen interest in the practice of (and before) Energy Regulators. These discussions and his writing on the topic have challenged me and assisted me in developing my thoughts on these subjects. See: D. Mullan, “The Supreme Court and the Duty to Consult Aboriginal Peoples: A Lifting of the Fog?” 24 CJALP 233; and D. Mullan, “Regulators and the Courts: A Ten Year Perspective”, Vol. 1 Energy Regulation Quarterly 13, especially Section 14 “Duty to Consult with Aboriginal Peoples.”

duty to consult:

“The duty on a tribunal to consider consultation and the scope of that inquiry depends on the mandate conferred by the legislation that creates the tribunal. Tribunals are confined to the powers conferred on them by their constituent legislation ... the role of particular tribunals in relation to consultation depends on the duties and powers the legislature has conferred on it.

The legislature may choose to delegate to a tribunal the Crown’s duty to consult. As noted in *Haida Nation*, it is open to governments to set up regulatory schemes to address the procedural requirements of consultation at different stages of the decision-making process with respect to a resource.

Alternatively, the legislature may choose to confine a tribunal’s power to determinations of whether adequate consultation has taken place, as a condition of its statutory decision-making process. In this case, the tribunal is not itself engaged in the consultation. Rather, it is reviewing whether the Crown has discharged its duty to consult with a given First Nation about potential adverse impacts on their Aboriginal interest relevant to the decision at hand.

Tribunals considering resource issues touching on Aboriginal interests may have neither of these duties, one of these duties, or both depending on what responsibilities the legislature has conferred on them. ...”<sup>68</sup>

This right of the legislature to determine the mandate of a tribunal results in one of four scenarios:

- the Energy Regulator fulfills the role of engaging in consultation;
- the Energy Regulator fulfills the role of adjudicating the adequacy of consultation;

- the Energy Regulator fulfills both of the above roles; or
- the Energy Regulator fulfills neither of the above roles.

When faced with issues regarding the duty to consult, the first task of the Energy Regulator (and those appearing before them) ought to be to determine which of the above scenarios applies. All too often, the debate—both academic and in the hearing rooms—has focused on what role the Energy Regulator *ought* to play and the legitimacy and/or efficacy of the alternative means by which the Crown can either carry out consultation and/or assess its adequacy. A commonly invoked passage in this regard is the Court’s statement that: “specialized tribunals with both the expertise and authority to decide questions of law are in the best position to hear and decide constitutional questions related to their statutory mandates.”<sup>69</sup> However, regardless of who may be in the best position to hear and decide (and it is often a matter of perspective as to who is in the best position), it is clear that, when it comes to the role of the Energy Regulator and the duty to consult, the choice is with the government. The relevant legal inquiry is into legislative intent.

While the legal question may be clear, unfortunately the answer is not always so obvious. In the vast majority of instances, the legislative foundations of today’s Energy Regulators were laid down at a time when the duty to consult was not (as it is today) an issue that attracted much focus. In the absence of explicit guidance, Energy Regulators will have to search for clues in their existing legislative scheme.

Two key indicia are (i) the power to consider questions of law, and (ii) the remedial powers granted to the Energy Regulator.

Both the powers of the tribunal to consider questions of law and the remedial powers granted it by the legislature are relevant considerations in determining the contours of that tribunal’s jurisdiction: *Conway*. As

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<sup>68</sup> *Rio Tinto*, *supra* note 2 at paras 55-58.

<sup>69</sup> *R v Conway*, 2010 SCC 22 at para 6, [2010] 1 SCR 765.

such, they are also relevant to determining whether a particular tribunal has a duty to consult, a duty to consider consultation, or no duty at all.

...In order for a tribunal to have the power to enter into interim resource consultations with a First Nation, pending the final settlement of claims, the tribunal must be expressly or impliedly authorized to do so. The power to engage in consultation itself, as distinct from the jurisdiction to determine whether a duty to consult exists, cannot be inferred from the mere power to consider questions of law. Consultation itself is not a question of law; it is a distinct and often complex constitutional process and, in certain circumstances, a right involving facts, law, policy, and compromise. The tribunal seeking to engage in consultation itself must therefore possess remedial powers necessary to do what it is asked to do in connection with the consultation...

A tribunal that has the power to consider the adequacy of consultation, but does not itself have the power to enter into consultations, should provide whatever relief it considers appropriate in the circumstances, in accordance with the remedial powers expressly or impliedly conferred upon it by statute.<sup>70</sup>

It is not relevant to the inquiry to ask whether or not there is some other administrative or regulatory tribunal that can or will fulfill the role. The Crown cannot avoid its duty to Aboriginal peoples by simply choosing to not assign one or both these functions (i.e. carrying out consultation and/or assessing the adequacy of consultation) to a particular Energy Regulator. The Court was clear in *Rio Tinto* that the honour of the Crown cannot be avoided.

“The fear is that if a tribunal is denied the power to consider consultation issues, or if

the power to rule on consultation is split between tribunals so as to prevent any one from effectively dealing with consultation arising from particular government actions, the government might effectively be able to avoid its duty to consult.

...the duty to consult with Aboriginal groups, triggered when government decisions have the potential to adversely affect Aboriginal interests, is a constitutional duty invoking the honour of the Crown. It must be met. If the tribunal structure set up by the legislature is incapable of dealing with a decision's potential adverse impacts on Aboriginal interests, then the Aboriginal peoples affected must seek appropriate remedies in the courts: *Haida Nation*, at para. 51.<sup>71</sup>

While there may still be legitimate *policy* debate about where or by whom the duty to consult should be discharged and/or adjudicated, such policy debate should be separate and distinct from any *legal* debate about whether the Energy Regulator plays any role in carrying out and/or adjudicating the adequacy of consultation. The proper legal question is: What role has the legislature assigned the Energy Regulator?

This is not dissimilar to the situation that arose following the introduction of the Charter, and questions arose with respect to the role of administrative tribunals in applying the Charter. Following the introduction of the Charter, there was a lengthy legal and policy debate (in and out of the courts) regarding the role of administrative tribunals in applying and interpreting the Charter. Ultimately, the Supreme Court of Canada clarified the guiding principle was determining the legislative intent.<sup>72</sup> In so doing, the Court made it clear that it was open to legislators to express their intent more clearly. Alberta<sup>73</sup> and British Columbia<sup>74</sup> both took up the Court's invitation and passed statutes clarifying the role of administrative tribunals

<sup>70</sup> *Rio Tinto*, *supra* note 2 at paras 58-61.

<sup>71</sup> *Ibid.*

<sup>72</sup> See *Nova Scotia (Workers' Compensation Board) v Martin*, 2003 SCC 54, [2003] 2 SCR 504; *Paul v British Columbia (Forest Appeals Commission)*, 2003 SCC 55, [2003] 2 SCR 585.

<sup>73</sup> See *Administrative Procedures and Jurisdiction Act*, RSA 2000, c A-3, s 16 and the *Designation of Constitutional Decision Makers Regulation*, Alta Reg 69/2006.

<sup>74</sup> See *Administrative Tribunals Act*, SBC 2004, c 45, s 43-45.

in respect of constitutional questions.<sup>75</sup> Certain definitional challenges remain in terms of how this legislation defines a “constitutional question” and debate has already arisen regarding the extent to which the duty to consult invokes such “constitutional questions.” However, the law is now clear that legislative intent is the guiding principle and it is open to legislators to clearly express their intent regarding the role of Energy Regulators. As will be discussed below (in relation to Alberta), some legislatures are also taking up this invitation from the Court and are expressly defining the role of Energy Regulators in respect of the duty to consult.

#### *Different Regulatory Decision-Making Structures*

Further guidance might be obtained by looking at how the role the Energy Regulator fits into the overall decision-making or approval process for a project. It is useful to distinguish between a couple of basic scenarios:

- Some Energy Regulators make the final decision which enables a proponent to proceed with a project. For example, it may be the Energy Regulator that directly issues a Certificate of Public Convenience and Necessity or other licence, permit or authorization.
- Some Energy Regulators make a “decision” in respect of such an authorization; however that decision is subject to the approval or confirmation of the Governor in Council (or Lieutenant-Governor in Council) or Minister(s) before the decision of the Energy Regulator is effective.<sup>76</sup> Alternatively, some Energy Regulators make a “recommendation” in respect of such an authorization; however the ultimate decision is made by the Governor in Council (or Lieutenant- Governor in

Council) or Minister(s).

It is important to note that a single Energy Regulator may have more than one variety of decision-making structure contained within its statute. The Energy Regulator may make final decisions on certain types of applications, while its decisions (or recommendations) under other sections of its statute may be only the first stage in the decision-making process and subject to further steps by the (Lieutenant) Governor in Council.

As will be seen in the discussion below, these different decision-making structures may give rise to different requirements regarding the duty to consult at different stages of the process.

#### *Different Types of Applicants*

Another factor to consider is whether the party appearing in front of the Energy Regulator is a Crown agent or a private party. The role of an Energy Regulator may differ in each scenario. As discussed in Part II, the Crown has the legal duty to consult, although the Crown may delegate procedural aspects of consultation to industry proponents. The proper role of the Energy Regulator may well be different when considering an application from a (private) industry proponent compared to an application by the Crown or agent of the Crown.

As will be seen in the discussion below, some regulators (and courts) have correctly drawn a clear distinction between the role of the Energy Regulator when considering an application brought by a Crown agent and an application brought by a private party.

#### **The Role of the Regulator: Three Case Studies**

The above factors should be kept in mind when considering the jurisprudence below. It is easy to fall into error when attempting to transport

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<sup>75</sup> In *Rio Tinto*, *supra* note 2 at para 72, the Court considered the application of the BC legislation in respect of the BCUC and concluded that it did not preclude the BCUC from determining the adequacy of consultation in respect of the application before it. The Court found that “the provisions of the *Administrative Tribunals Act* and the *Constitutional Question Act* do not indicate a clear intention on the part of the legislature to exclude from the Commission’s jurisdiction the duty to consider whether the Crown has discharged its duty to consult with holders of relevant Aboriginal interests.”

<sup>76</sup> A variation on this structure is where the Energy Regulator makes a decision, which is final subject to the ability of a Minister (or other government actor) to override or set aside that decision.

the findings of one case (dealing with a different piece of legislation, a different decision-making structure and/or a different type of applicant) to another situation. The case studies below will review the existing and developing jurisprudence in respect of the B.C. Utilities Commission, the National Energy Board and the Alberta Energy Regulator.<sup>77</sup>

#### *The British Columbia Utilities Commission*

The Supreme Court of Canada applied its test to the BC Utilities Commission after it laid out the general principles in *Rio Tinto*. The first factor considered was that the *Utilities Commission Act* gave the Commission the power to decide questions of law.

“The power to decide questions of law implies a power to decide constitutional issues that are properly before it, absent a clear demonstration that the legislature intended to exclude such jurisdiction from the tribunal’s power ...”<sup>78</sup>

In addition, the statutory provision (at the time) at issue also empowered the Commission to consider “any other factor that the commission considers relevant to the public interest.”

“The constitutional dimension of the duty to consult gives rise to a special public interest, surpassing the dominantly economic focus of the consultation under the Utilities Commission Act.”<sup>79</sup>

Finally, the Court concluded that the legislation did “not indicate a clear intention on the part of the legislature to exclude from the Commission’s jurisdiction the duty to consider whether the Crown has discharged its duty to consult with

holders of relevant Aboriginal interests.”<sup>80</sup>

In the result, the Court concluded that (i) the Commission had the power to consider whether adequate consultation had taken place, however (ii) the Commission did have the power to engage in consultations itself in order to discharge the Crown’s constitutional obligation to consult.<sup>81</sup>

Some commentators appear to suggest that this is a conclusion that applies with equal force to all Energy Regulators in all circumstances. However, far from being universally applicable conclusions, the Court’s conclusion in *Carrier Sekani* regarding the BCUC was one firmly grounded in the context of the case before it. It is important to note that the application before the BCUC was an application where the final decision rested with the BCUC.<sup>82</sup> It was not an application where the decision of the BCUC was subject to the approval of the Lieutenant Governor in Council or other decision-making authority. There was no other stop in the decision-making process where the ultimate decision was made and/or the adequacy of consultation in respect of that decision might be adjudicated.

Also, it is important to note that the Commission was considering an application from BC Hydro—an agent of the Crown. This clearly impacted the Court’s consideration.

“BC Hydro is a Crown corporation. It acts in place of the Crown. No one seriously argues that the 2007 EPA does not represent a proposed action of the province of British Columbia.”<sup>83</sup>

The consultation (or lack there of) carried out

<sup>77</sup> These three Energy Regulators were chosen because the issue of their role in respect of the duty to consult has been more extensively litigated—or at least I am more familiar with the existing jurisprudence in respect of these three regulators.

<sup>78</sup> *Rio Tinto*, *supra* note 2 (at para. 69.)

<sup>79</sup> *Ibid* at at para 70.

<sup>80</sup> *Ibid* at para 72.

<sup>81</sup> *Ibid* at para 74.

<sup>82</sup> The Commission was charged with determining whether the sale of electricity was in the public interest under the then-current version s. 71 of the *Utilities Commission Act*, RSBC 1996, c 473. The Commission had the power to declare a contract for the sale of electricity unenforceable if it found that it was not in the public interest having regard to a specified list of factors, including “any other factor that the commission considers relevant to the public interest”. Section 71 of the *Utilities Commission Act*, RSBC 1996, c 473 has since been amended.

<sup>83</sup> *Rio Tinto*, *supra* note 2 at para 81.

by the Applicant (a Crown agent) fell clearly within the scope of the application before the Commission. (This is in contrast to the situation discussed below where the applicant is a private party and the Crown (and the evidence of its consultation efforts) is not before the Energy Regulator.)

Nigel Bankes has argued forcefully to the contrary and suggested that “there is no suggestion here that the ‘special public interest’ is created by the fact that the applicant for the statutory approval in *Carrier Sekani* was an agent of the Crown.”<sup>84</sup> With greatest respect (and I certainly have a lot for Nigel Bankes), what this and similar commentaries seem to ignore is that an Energy Regulator has the power to decide constitutional questions that arise in respect of the application before it—not constitutional questions at large. If the Crown is not a party before the Energy Regulator, there is no basis for extending the mandate of the Energy Regulator to assessing the adequacy of Crown consultation.

The BCUC has clearly acknowledged the significance of having a Crown agent as an applicant. In March 2010,<sup>85</sup> the Commission introduced “2010 First Nations Information Filing Guidelines for Crown Utilities.”<sup>86</sup> The focus on “Applications and filings made by a Crown utility” reflects the unique situation that arises when a Crown agent is also the industry proponent appearing before the Energy Regulator.

The specific context of the *Rio Tinto* decision and the BCUC’s statute cannot be ignored. The Court’s conclusions in respect of the BCUC cannot be universally applied to all Energy Regulators. It can easily lead to err to attempt to transport the Court’s conclusions in respect of the BCUC into a different context where there is a different statute, a different decision-making structure and/or a different type of applicant. The contrast can be seen by

examining a scenario where there is a different decision-making structure (as at the National Energy Board) and a private (non-Crown) applicant.

#### *National Energy Board*

Ten years before the duty to consult was articulated by the Supreme Court of Canada (in 2004 in the *Haida* and *Taku* decisions), the Supreme Court of Canada considered the National Energy Board’s regulatory and administrative processes in respect of the fiduciary duty owed by government to First Nations in certain circumstances. In *Quebec (Attorney General) v. Canada (National Energy Board)* the Court commented on the NEB’s hearing process:

Counsel for the appellants conceded in oral argument that it could not be said that such a duty should apply to the courts, as a creation of government, in the exercise of their judicial function. In my view, the considerations which apply in evaluating whether such an obligation is impressed on the process by which the Board decides whether to grant a licence for export differ little from those applying to the courts. The function of the Board in this regard is quasi-judicial: *Committee for Justice and Liberty v. National Energy Board*, [1978] 1 S.C.R. 369, at p. 385. While this characterization may not carry with it all the procedural and other requirements identical to those applicable to a court, it is inherently inconsistent with the imposition of a relationship of utmost good faith between the Board and a party appearing before it. ...

Therefore, I conclude that the fiduciary relationship between the Crown and the appellants does not impose a duty on the Board to make its decisions in the best interests of the appellants, or to change its hearing process so as to impose superadded

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<sup>84</sup> Nigel Bankes, “Who decides if the Crown has met its duty to consult and accommodate?” (6 September 2012), online: <[http://ablawg.ca/wp-content/uploads/2012/09/Blog\\_NB\\_Who\\_Decides\\_Sept-20123.pdf](http://ablawg.ca/wp-content/uploads/2012/09/Blog_NB_Who_Decides_Sept-20123.pdf)> at page 5.

<sup>85</sup> Following the February 18, 2009 decisions of the British Columbia Court of Appeal in *Carrier Sekani Tribal Council v. British Columbia (Utilities Commission)*, 2009 BCCA 67 and *Kwikwetlem First Nation v. British Columbia (Utilities Commission)*, 2009 BCCA 68.

<sup>86</sup> BCUC Order G-51-10 (18 March 2010), online: BCUC <[http://www.bcuc.com/Documents/Guidelines/2010/DOC\\_25327\\_G-51-10\\_2010-First-Nations-Information-Filing-Guidelines.pdf](http://www.bcuc.com/Documents/Guidelines/2010/DOC_25327_G-51-10_2010-First-Nations-Information-Filing-Guidelines.pdf)>.

requirements of disclosure. When the duty is defined in this manner, such tribunals no more owe this sort of fiduciary duty than do the courts. Consequently, no such duty existed in relation to the decision-making function of the Board.

Moreover, even if this Court were to assume that the Board, in conducting its review, should have taken into account the existence of the fiduciary relationship between the Crown and the appellants, I am satisfied that, for the reasons set out above relating to the procedure followed by the Board, its actions in this case would have met the requirements of such a duty. There is no indication that the appellants were given anything less than the fullest opportunity to be heard. They had access to all the evidence that was before the Board, were able to make submissions and argument in reply, and were entitled to cross-examine the witnesses called by the respondent Hydro-Quebec...”<sup>87</sup>

In the wake of *Haida*, *Taku* and *Mikisew*, some thoughtful commentators suggested that the 1994 decision may no longer be good law. This view seemed to be born of the conclusion that Energy Regulators (such as the NEB) were themselves to be equated with the Crown whose decisions could themselves trigger a duty to consult. With respect, I believe this view to be mistaken. While the fiduciary obligation and the duty to consult serve different purposes and arise in different circumstances,<sup>88</sup> both duties (the fiduciary duty and the duty to consult) have their origins in the honour of the Crown. It is no more necessary to impose the duty to consult on an Energy Regulator than it was to impose a fiduciary obligation on an Energy Regulator. As discussed further below, the Court’s decision in *Quebec (Attorney General) v. Canada (National Energy Board)* still holds valuable lessons in considering the NEB’s role in relation to the duty to consult—especially in circumstances where (unlike in *Rio Tinto*) the

applicant is a private party and not a Crown agent.

The NEB also has (and had) a different decision-making structure from the BCUC process considered in *Rio Tinto*. Prior to recent amendments (discussed below), the *National Energy Board* was an example of an Energy Regulator that, in certain applications, made a decision that was subject to the approval of the Governor in Council. The former version of s. 52 of the *National Energy Board Act* provided:

“The Board may, subject to the approval of the Governor in Council, issue a certificate in respect of a pipeline if the Board is satisfied that the pipeline is and will be required by the present and future public convenience and necessity and, in considering an application for a certificate, the Board shall have regard to all considerations that appear to it to be relevant...”

This two-step decision-making structure created two potential avenues for legal challenge. Under the former version of s. 52 of the *National Energy Board Act*, the two avenues were:

- An appeal (with leave) of the NEB decision; and
- Judicial Review of the Governor in Council’s approval.

Both of these challenges arose following three separate decisions by the NEB in 2007/2008 in respect of three separate pipelines and the three subsequent Orders-in-Council granting approvals for three Certificates of Public Convenience and Necessity for the following projects: the Keystone Pipeline Project<sup>89</sup>; the Southern Lights Pipeline Project<sup>90</sup>; and the Alberta Clipper Pipeline Expansion Project.<sup>91</sup>

#### *i. National Energy Board Decisions*

In each of these three proceedings, the NEB

<sup>87</sup> *Quebec (Attorney General) v. Canada (National Energy Board)*, [1994] 1 SCR 159, 1994 CanLII 113 (SCC), 31.

<sup>88</sup> See the discussion in Sanderson et al., *supra* note 21, pages at 835.

<sup>89</sup> NEB Decision OH-1-2007, (6 September 2007); and Order in Council No PC 2007-1786 (22 November 2007).

<sup>90</sup> NEB Decision OH-3-2007, (19 February 2008); Order in Council No PC 2008-856 (8 May 2008).

<sup>91</sup> NEB Decision OH-4-2007, (22 February 2008); and Order in Council No PC 2008-857 (8 May 2008).

heard from numerous Aboriginal groups—some of which expressly asked the Board to address the jurisdictional question of whether the Crown's duty to consult had been fulfilled in accordance with the test in *Haida*. The Board took the view that, in adjudicating the pipeline applications before it, it did not have a duty to determine whether the honour of the Crown had been maintained in the *Haida* sense, but did consider the proponent-led consultation with First Nations took place pursuant to the Board's filing guidelines and regulatory process. For example, in the Southern Lights decision, the Board stated:

"The Board disagrees with Standing Buffalo's position that, before it considers the substantive merits of the certificate application, it must determine the strength of Standing Buffalo's claim and assess the adequacy of Crown consultation. The Board's process is designed to ensure that it has a full understanding of the concerns that Aboriginal people have in relation to a project, before it renders its decision. Aboriginal people who have an interest in a project are able to participate in the regulatory process on several levels. The Board weighs and analyzes the nature of the Aboriginal concerns and the impacts a proposed project might have on those interests as part of its overall assessment of whether or not the Project is in the public interest. The Board is of the view that the process it followed in the evaluation of the Project ensures that the decisions of the Board in respect of the Project will be made in accordance with all legal imperatives."<sup>92</sup>

The NEB issued a favourable decision in respect of all three pipelines, and subsequently the Governor in Council gave its approval (in the form of Orders in Council) in respect of all three pipelines.

ii. *Federal Court litigation – challenge to the Governor in Council approval*

Several First Nations<sup>93</sup> that did not participate in the National Energy Board hearings brought judicial review proceedings<sup>94</sup> challenging the three Orders in Council (that approved the three NEB decisions). The Federal Court dismissed the applications. In the *Brokenhead Ojibway* decision, the Federal Court stated:

In determining whether and to what extent the Crown has a duty to consult with Aboriginal peoples about projects or transactions that may affect their interests, the Crown may fairly consider the opportunities for Aboriginal consultation that are available within the existing processes for regulatory or environmental review. ...Those review processes may be sufficient to address Aboriginal concerns, subject always to the Crown's overriding duty to consider their adequacy in any particular situation. This is not a delegation of the Crown's duty to consult but only one means by which the Crown may be satisfied that Aboriginal concerns have been heard and, where appropriate, accommodated: see *Haida*, above, at para. 53 and *Taku*, above, at para. 40.<sup>95</sup>

Even where the ultimate decision rests with the government, the process of the Energy Regulator can play a supporting if not central role. Many Aboriginal groups had discounted the role of Energy Regulators (and other administrative tribunals and processes) on the grounds that they were entitled to a separate and distinct process focused exclusively on their interests. They did so often in reliance on a passage from *Mikisew Cree*, which states that, in the circumstances of that case, the Crown "was required to provide notice to the Mikisew and to engage directly with them and not ... as an afterthought to a general public

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<sup>92</sup> See for instance, *Enbridge Southern Lights LP (Re)*, 2008 LNCNEB 1 (No OH-3-2007), at paras 56-57.

<sup>93</sup> Brokenhead Ojibway Nation, Long Plain First Nation, Swan Lake First Nation, Fort Alexander First Nation, Roseau River Anishinabe First Nation, Peguis First Nation, Sandy Bay First Nation (collectively, the "the Treaty One First Nations").

<sup>94</sup> There was one judicial review for each Order in Council – for a total of three. See Federal Court Files: T-225-08, T-921-08 and T-925-08.

<sup>95</sup> *Brokenhead Ojibway First Nation v Canada (Attorney General)*, 2009 FC 484 at para 25 [*Brokenhead Ojibway*]. This statement was adopted by the Alberta Court of Appeal in *Tsuu T'ina Nation v Alberta (Environment)*, 2010 ABCA 137 at para 104.

consultation with Park users.”<sup>96</sup>

In *Brokenhead*, the Court made it clear that the process of the Energy Regulator (in this case the NEB) had an important role to play and that the opportunity should not be squandered.

“The fact that the Treaty One First Nations may not have availed themselves fully of the opportunity to be heard before the NEB does not justify the demand for a separate or discrete consultation with the Crown. To the extent that regulatory procedures are readily accessible to Aboriginal communities to address their concerns about development projects like these, there is a responsibility to use them. First Nations cannot complain about a failure by the Crown to consult where they have failed to avail themselves of reasonable avenues for seeking relief. ... This presupposes, of course, that available regulatory processes are accessible, adequate and provide First Nations an opportunity to participate in a meaningful way.”<sup>97</sup>

It does not follow that the process of the NEB (or another Energy Regulator) will always be enough on its own to discharge the duty to consult that arises in respect of the decision of the Governor in Council. This was a case where the pipeline projects were found to have a fairly minor impact—given they were largely located on private, previously disturbed land and the Court found insufficient evidence to indicate a significant adverse impact. Also, the lands in question were subject to a historic treaty (Treaty No. 1). In these circumstances, the NEB process on its own was sufficient to discharge the duty—even in the absence of any further consultation to support the Governor in Council’s decision. However, the Court recognized that there may be circumstances where the Board process may be, on its own, insufficient.

“I have no doubt, however, that had any of

the Pipeline Projects crossed or significantly impacted areas of unallocated Crown land which formed a part of an outstanding land claim a much deeper duty to consult would have been triggered. Because this is also the type of issue that the NEB process is not designed to address, the Crown would almost certainly have had an independent obligation to consult in such a context.”<sup>98</sup>

The Federal Court’s decision was not appealed.

In summary, what the Court appears to be saying is that the Crown can rely on existing environmental and regulatory processes (like those of many Energy Regulators) in making Crown decisions. It is important to note that the Crown decision at issue here was the Order in Council—not the Board’s decision. In some circumstances, those existing processes may be enough to address the consultation requirements and the Crown will not be required to carry out any additional, independent consultation. However, in other circumstances (particularly where the potential adverse impact of the project is more significant), the Crown may be required to carry out additional, supplemental consultation with Aboriginal groups to inform its own decision-making process.

### iii. *Federal Court of Appeal Litigation – Challenge to the National Energy Board Decisions*

Meanwhile, a number of Aboriginal groups that had participated in the NEB process for these same three pipelines brought four separate appeals<sup>99</sup> that sought to challenge three decisions by the National Energy Board to issue Certificates of Public Convenience and Necessity. These four appeals were all heard together by the Federal Court of Appeal.

The Court’s decision in *Standing Buffalo Dakota First Nation v. Enbridge Pipelines Inc.* (“*Standing Buffalo*”),<sup>100</sup> identified the “novel

<sup>96</sup> *Mikiseu*, *supra* note 24 at para 64.

<sup>97</sup> *Brokenhead Ojibway*, *supra* note 95 at para 42.

<sup>98</sup> *Ibid* at para 44.

<sup>99</sup> The *Standing Buffalo* Dakota First Nations brought three separate challenges arising from the three decisions of the National Energy Board to issue Certificates of Public Convenience and Necessity (CPCN) for the three pipeline

question” raised as:

[W]hether before making its decisions in relation to those applications, the NEB was required to determine whether by virtue of the decision in *Haida Nation*, the Crown, which was not a party to those applications or a participant in the hearings, was under a duty to consult the First Nations with respect to potential adverse impacts of the proposed projects on the First Nations interest and if it was, whether that duty had been adequately discharged?<sup>101</sup>

The Court concluded that the NEB does not have duty to consult itself:

“...the NEB itself is not under a *Haida* duty and, indeed, the appellants made no argument that it was. The NEB is a quasi-judicial body (see *Quebec (Attorney General) v. Canada (National Energy Board)*, [1994] 1 S.C.R. 159, at page 184, and, in my view, when it functions as such, the NEB is not the Crown or its agent.”<sup>102</sup>

The Court noted (citing the decision of *Quebec (Attorney General) v. Canada (National Energy Board)*) that, in exercising its decision-making function, the NEB must act within the dictates of the Constitution, including s.35. The Court had little difficulty concluding that it had:

“...the NEB dealt with three applications for Section 52 Certificates. Each of those applications is a discrete process in which a specific applicant seeks approval in respect of an identifiable Project. The process focuses on the applicant, on whom the NEB imposes broad consultation obligations. The applicant must consult with Aboriginal groups, determine their concerns and attempt to address them, failing which the NEB can impose accommodative requirements. In my view, this process ensures that the

applicant for the Project approval has due regard for existing Aboriginal rights that are recognized and affirmed in subsection 35(1) of the Constitution. And, in ensuring that the applicant respects such Aboriginal rights, in my view, the NEB demonstrates that it is exercising its decision-making function in accordance with the dictates of subsection 35(1) of the Constitution.”<sup>103</sup>

Nevertheless, the Court concluded that the requirement to exercise its decision-making function within the dictates of the Constitution did *not* require the Board to determine whether the Crown was under, and had discharged, a *Haida* duty before making a decision on the application before it in these circumstances where the applicant was a private actor (and not a Crown agent). The Court found that these matters could be adjudicated by a court of competent jurisdiction.

The Court of Appeal in *Standing Buffalo* commented on (and endorsed the usefulness of) the role of the NEB process in a manner reminiscent of the Federal Court’s comments in *Brokenhead*:

“...the ability of an Aboriginal group to have recourse to the courts to adjudicate matters relating to the existence, scope and fulfillment of a *Haida* duty in respect of the subject matter of an application for a Section 52 Certificate should not be taken as suggesting that the Aboriginal group should decline to participate in the NEB process with respect to such an application. As previously stated, the NEB process focuses on the duty of the applicant for a Section 52 Certificate. That process provides a practical and efficient framework within which the Aboriginal group can request assurances with respect to the impact of the particular project on the matters of concern to it. While the Aboriginal group is free to determine the

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projects: Keystone Pipeline, Southern Lights Pipeline and the Alberta Clipper Pipeline. The Sweetgrass First Nation and the Moosimin First Nation brought an additional challenge arising from the NEB’s Alberta Clipper decision—for a total of four appeals. See Federal Court of Appeal Files: 08-A-25; 08-A-28; 08-A-29; and 08-A-30.

<sup>100</sup> *Standing Buffalo Dakota First Nation v Enbridge Pipelines Inc.*, 2009 FCA 308 [*Standing Buffalo*].

<sup>101</sup> *Ibid* at para 2.

<sup>102</sup> *Ibid* at para 34.

<sup>103</sup> *Ibid* at para 40.

course of action it wishes to pursue, it would be unfortunate if the opportunity afforded by the NEB process to have Aboriginal concerns dealt with in a direct and non-abstract matter was not exploited.<sup>104</sup>

*iv. Traffic Jam at the Supreme Court of Canada – Standing Buffalo and Rio Tinto*

The Federal Court of Appeal (per. Noel, Layden-Stevenson and Ryer JJ.A.) dismissed the *Standing Buffalo* appeals on October 23, 2009. Less than two weeks later, on November 5, 2009, the Supreme Court of Canada granted leave to appeal from the B.C. Court of Appeal decision in the *Rio Tinto* appeal.<sup>105</sup> The First Nations involved in the *Standing Buffalo* case sought leave to appeal to the Supreme Court of Canada and also sought to have the appeal process expedited and heard together with the appeal in *Rio Tinto*. Instead, the Supreme Court of Canada placed the applications for leave in abeyance until the appeal in *Rio Tinto* decision was heard and decided. Some of the applicant First Nations (Standing Buffalo Dakota First Nation and Moosomin First Nation) and the impacted pipelines (Enbridge Pipelines Inc. and TransCanada Keystone Pipeline GP Ltd.) applied for and were granted the right to join the *Rio Tinto* appeal as Intervenor. Thus, the significance of the issues raised in the *Standing Buffalo* appeal was before the Supreme Court of Canada when it considered and decided the *Rio Tinto* appeal.

The Supreme Court of Canada issued *Rio Tinto* decision (discussed above) on October 28, 2010. A few weeks later on December 2, 2010, the Court dismissed the applications for leave to appeal in the *Standing Buffalo* case.<sup>106</sup> (It is also notable that, in the intervening period,

on November 19, 2010, the Court released its decision in the *Little Salmon* appeal (discussed above).)

As a result of the Supreme Court denying leave to appeal in the *Standing Buffalo* case, we do not have the advantage of the Supreme Court of Canada's opinion on the role of the NEB as discussed in that decision.<sup>107</sup> Some commentators have expressed regret that the leave to appeal was denied and suggested it leaves the law uncertain.<sup>108</sup>

What is clear is that the Supreme Court of Canada—having recently given clear guidance on the role of regulatory tribunals in the *Rio Tinto* decision—was content to take a pass on revisiting the issue so quickly in the specific context of the NEB.

Given that the *Standing Buffalo* decision of the Federal Court of Appeal was released prior to the Supreme Court of Canada's decision in *Rio Tinto*, it is not surprising that the language and the analysis used in the decision does not precisely track completely with the *Rio Tinto* analysis. However, in summary what the Courts appears to have concluded about the NEB's regulatory process and Governor-in-General approval process (as it then was) is that:

- the NEB (like the BCUC) does not fulfill the role of engaging in Crown consultation;
- the NEB does fulfill the role of adjudicating the adequacy of consultation carried out by the (private) applicant, but
- The NEB does not fulfill the role of adjudicating the adequacy of

<sup>104</sup> *Ibid* at para 44.

<sup>105</sup> *Rio Tinto Alcan Inc. v Carrier Sekani Tribal Council - and - British Columbia Utilities Commission*, 2009 CanLII 61380.

<sup>106</sup> The *Standing Buffalo* leave to appeal application was considered and dismissed by the same panel of the Court that had granted leave in the *Rio Tinto* appeal. See 2010 CanLII 70763 (SCC); 2010 CanLII 70737 (SCC); 2010 CanLII 78628 (SCC); 2010 CanLII 74561 (SCC); and 2010 CanLII 70764 (SCC). The Supreme Court of Canada does not provide reasons when dismissing applications for leave to appeal.

<sup>107</sup> Perhaps because the leave to appeal application was still pending at the time it decided the *Rio Tinto* appeal, the Supreme Court of Canada did not reference or comment on the Federal Court of Appeal's decision in *Standing Buffalo* (even though many of the parties in the *Standing Buffalo* appeal participated in the *Rio Tinto* appeal as intervenors).

<sup>108</sup> D. Mullan, *supra* note 52, 67 CJALP 233 at 259: "...the Supreme Court, in the interests of rounding the circle on the issue of tribunal consultation, should have given leave in *Standing Buffalo*. *Carrier Sekani* did not resolve all of the issues raised by that Federal Court of Appeal decision."

consultation carried out by the Crown (when the Crown is not a party before it and when the Crown decision (i.e. the Order in Council) is made subsequent to the NEB regulatory process), and

- The Governor in Council approval of the NEB decision can rely on the existing regulatory process as discharging (in whole or in part) the duty to consult. In some circumstances, the regulatory process may be enough in and of itself, but in some circumstances the Crown may be required to conduct further direct consultation in order to discharge the duty to consult.

Some have asked how the process of the Energy Regulator that does not play the role of consulting or adjudicating the adequacy of consultation can then subsequently be relied on by the Crown to discharge (in whole or in part) the Crown's duty to consult. The answer is quite straightforward. If the tribunal is not charged with consulting and/or assessing the adequacy of Crown consultation, the process before, and the decision of, an Energy Regulator may nevertheless assist the Crown in meeting its obligation to act honourably if the Energy Regulator's statutory mandate requires it to have sufficient regard to First Nation interests in the circumstances. The process of an Energy Regulator can provide significant procedural support by ensuring that First Nations are provided with:

- a. adequate notice of a proposal;
- b. all necessary information in a timely way;
- c. the opportunity to engage in direct consultation with the applicant and/or attend regulatory hearings proceedings and lead or elicit evidence;
- d. an opportunity to express their interests and concerns through submissions to the Energy Regulator; and
- e. having those submissions given full, fair and serious consideration

in the formulation of a decision, recommendation and/or conditions to be imposed on the project.

These elements assist in fulfilling the requirements of the Crown's duty.<sup>109</sup> If properly conducted, the process of an Energy Regulator can provide these elements and assist in maintaining the honour of the Crown. In some circumstances, this process may be enough on its own to support a Crown decision; however, in some cases more may be required.

This appears consistent with how the NEB subsequently understood and articulated its role. For example, in the NEB's March 2010 decision in respect of the Keystone XL Pipeline Project, the Board further explained its view of how its process fit in respect of the Crown duty to consult.

"The Board is governed by a variety of legislative and Common Law requirements and is a court of record that operates independently and at arm's length from the government of Canada. It is not the same thing as "the Crown" because it is an independent tribunal that is not subject to direction by the Crown. ... In respect of the Crown's Aboriginal consultation obligations, this legislative structure provides particular challenges not faced by federal departments directed by Ministers of the Crown. In light of the specific legislative structure established in 1959 by parliament under the NEB Act, the Crown has determined that it will rely on the NEB process as a means to meet some or all of its consultation obligations in respect of matters that fall within the mandate of the NEB. This does not mean that the Crown has delegated its duty to consult to the Board. The Board has jurisdiction to consider whether a project is in the public interest and as a part of that consideration it weighs the costs and benefits of the project, including its potential effects on Aboriginal interests."<sup>110</sup>

These observations in respect of the NEB are

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<sup>109</sup> See *Mikisew*, *supra* note 24 at para 64; citing *Halfway River First Nation v BC (Ministry of Forests)*, 1999 BCCA 470 at paras 159, 160, 64 BCLR (3d) 206, Finch J.A.

<sup>110</sup> *TransCanada Keystone Pipeline GP Ltd. (Re)*, 2010 LNCNEB 2 (No OH-1-2009) at para 87.

also not universally applicable conclusions to all Energy Regulators. Again, what is critical is to examine the role given to the Energy Regulator by the legislation. The duty on an Energy Regulator to consider consultation and the scope of that inquiry depends on the mandate conferred by the legislation that creates or continues it. That role may be different depending on the nature of the decision-making structure and on the nature of the Applicant (Crown agent or private party) appearing before it.

*v. National Energy Board – Current Legislation*

Since the court decisions discussed above, the relevant sections of the *National Energy Board Act* have been amended. The recent amendments slightly alter the respective roles of the NEB and the Governor in Council, although the scope of the Board's considerations remains unchanged. The table below compares the former version of section 52 (considered by the Federal Court of Appeal in the *Standing Buffalo* case) and the

revised (currently contained in the *National Energy Board Act*) with the material changes highlighted.

Whereas the National Energy Board formerly “issued” a CPCN “subject to the approval” of the Governor in Council, the Board now makes a “recommendation” as to whether or not the certificate should be issued. Section 54 of the current *National Energy Board Act* provides that, after the Board has submitted its report under section 52, the Governor in Council may (a) direct the Board to issue a certificate or (b) direct the Board to dismiss the application for a certificate. Together, sections 52 and 54 of the current legislation make clear the respective roles of the Board and the Governor in Council. Clearly, the decision to “direct” the Board to issue or dismiss the application for a certificate rests with the Governor in Council under section 54(1) of the Act. Section 55 of the Act provides that any order made under subsection 54(1) can be challenged (with leave of the Court) by judicial review by the Federal Court of Appeal.

<i>National Energy Board Act</i> , RSC 1985, c. N-7, section 52 (former version)	<i>National Energy Board Act</i> , RSC 1985, c. N-7, section 52 (as amended)
<p>52. <u>The Board may, subject to the approval of the Governor in Council, issue a certificate</u> in respect of a pipeline if the Board is satisfied that the pipeline is and will be required by the present and future public convenience and necessity and, in considering an application for a certificate, the Board shall have regard to all considerations that appear to it to be relevant, and may have regard to the following:</p> <p>(a) the availability of oil, gas or any other commodity to the pipeline;</p> <p>(b) the existence of markets, actual or potential;</p> <p>(c) the economic feasibility of the pipeline;</p> <p>(d) the financial responsibility and financial structure of the applicant, the methods of financing the pipeline and the extent to which Canadians will have an opportunity of participating in the financing, engineering and construction of the pipeline; and</p> <p>(e) any public interest that in the Board's opinion may be affected by the granting or the refusing of the application.</p>	<p>52. (1) If <u>the Board</u> is of the opinion that an application for a certificate in respect of a pipeline is complete, it <u>shall prepare and submit to the Minister, and make public, a report setting out (a) its recommendation as to whether or not the certificate should be issued...</u></p> <p>(2) In making its recommendation, the Board shall have regard to all considerations that appear to it to be directly related to the pipeline and to be relevant, and may have regard to the following:</p> <p>(a) the availability of oil, gas or any other commodity to the pipeline;</p> <p>(b) the existence of markets, actual or potential;</p> <p>(c) the economic feasibility of the pipeline;</p> <p>(d) the financial responsibility and financial structure of the applicant, the methods of financing the pipeline and the extent to which Canadians will have an opportunity to participate in the financing, engineering and construction of the pipeline; and</p> <p>(e) any public interest that in the Board's opinion may be affected by the issuance of the certificate or the dismissal of the application.</p>

Given the clear lines of responsibility (and the clear lines for challenging the resulting decisions), it is submitted that any determination regarding the legitimacy or constitutionality of the decision the Governor in Council may ultimately make is clearly beyond the mandate of an NEB hearing panel to determine. The Joint Review Panel hearing the Northern Gateway Pipeline application stayed true to this approach in its recent ruling dated 9 April 2013:

The Panel cannot consider the constitutionality of decisions that are beyond its mandate. This would include the ultimate decision of GiC as to whether to order the Board to issue a Certificate and how the Board will apply its legislation in issuing a Certificate. The decision of the GiC and any potential issuance of a Certificate will be undertaken well after the Panel has issued its report. These decisions and actions are beyond the Panel's mandate. In accordance with section 55 of the NEB Act, any decision of GiC may be challenged before the Federal Court of Appeal, on judicial review.<sup>111</sup>

The Joint Review Panel issued its final report on December 19, 2013, and described its role as follows under the heading "Participation by Aboriginal groups":

"Our hearing process provided an opportunity for Aboriginal people to learn more about the project and to place on our record their views about:

- their traditional knowledge with respect to the environmental effects;
- the effects any change in the environment resulting from the project may have on their current use of lands and resources for traditional purposes; and

- the nature and scope of their potential or established Aboriginal and treaty rights, the effects the project may have on those rights, and appropriate measures to avoid or mitigate such effects.

Aboriginal people participated as intervenors in the final hearing process and through oral evidence, oral statements, and letters of comment. Many attended our information sessions and hearings.

Under the Joint Review Panel Agreement, our process received information on the nature and scope of potential or established Aboriginal and treaty rights that the project might affect and the effects that the project might have on these rights. We received a great deal of evidence from Aboriginal groups and other parties on these matters."<sup>112, 113</sup>

Under both the old and new versions of its legislative mandate, the Board's process is well designed to elicit, hear and consider evidence of Aboriginal interests and potential impacts of proposed projects. The Board will also consider the consultation process carried out by the (private) applicants appearing before it. This process can be relied upon by the Crown when making its own decision—i.e. determining whether to direct the Board to issue a certificate. In some circumstances, the Crown may be satisfied that the direct consultation between the proponent and Aboriginal groups, combined with the access of Aboriginal groups to the Energy Regulator's process has upheld the honour of the Crown. In other circumstances (such as where the potential impact of a project has greater potential for adverse impacts), the Crown may choose to undertake further consultation to ensure the honour of the Crown is upheld.<sup>114</sup> The adequacy of the Crown's ultimate decision can be challenged, with leave, by judicial review in the Federal Court

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<sup>111</sup> *Joint Review Panel Decision* (9 April 2013) at page 6.

<sup>112</sup> See *Report of the Joint Review Panel for the Enbridge Northern Gateway Project*, Volume 1 "Connections", section 2.2.1.

<sup>113</sup> It should be noted that a number of Aboriginal and environmental groups have commenced litigation in the Federal Court of Appeal seeking to challenge and/or set aside the Joint Review Panel's report. Given the early stage of this litigation, and the involvement of the author as counsel to an intervenor in the Joint Review Panel process, this article will unfortunately have to refrain from direct comment on this pending litigation.

<sup>114</sup> A similar discussion of the Board process (under the former version of the legislation) was earlier published in the *Alberta Law Review* article by Sanderson et. al., *supra* note 21, at page 848-49.

of Appeal. This is entirely consistent with the principles established by the Court's decision in *Carrier Sekani*.

#### *Alberta Energy Regulator*

While the remaining space and time do not permit an extended discussion, it is necessary to comment briefly on recent (and ongoing) developments in respect of energy/regulatory practice in Alberta.

Issues regarding the role of the Energy Regulator in relation to the duty to consult arose a number of times in relation to the (former) the Energy Resources Conservation Board (ERCB).

In the Osum Decision,<sup>115</sup> the ERCB determined that it did not have jurisdiction to determine whether the Crown discharged its duty to consult and accommodate the Cold Lake First Nations in relation to the adverse impact arising from an Oil Sand project. The Board drew a distinction based on the fact that the applicant before it was not a Crown agent:

"The Board is not satisfied that in this matter, where the proponent is not the Crown or a Crown or a Crown agent and thus does not owe the constitutional duty, the ERCB's public interest mandate extends to assessing the adequacy of Crown conduct (consultation) which has yet to be completed."<sup>116</sup>

Following the Boards' decision, the First Nation reached an agreement with the proponent and withdrew its objection to the project. Nevertheless, the First Nation sought leave to appeal on the basis that the question was one of general importance. The Alberta Court of Appeal denied leave to appeal on the basis that the issue was moot. The Court also noted that "the issue will shortly come before the ERCB in the context of a concrete dispute which, on

its face, engages the same question that the Applicant seeks to advance before this Court."<sup>117</sup>

The pending dispute that the Court of Appeal was referring to was the Notice of Constitutional Question filed by the Athabasca Chipewyan First Nation as part of the Joint Review Panel for Shell's Jackpine Project. The Agreement that established the Joint Review Panel for that project made it clear that the Joint Review Panel "may receive information from Aboriginal groups related to the nature and scope of asserted or established Aboriginal and treaty rights in the area of the project, as well as information on the potential adverse environmental effects that the project may have on asserted or established Aboriginal and treaty rights"<sup>118</sup> and "may use this information to make recommendations that relate to the manner in which the project may adversely affect the Aboriginal and treaty rights asserted by participants."<sup>119</sup> However, the Agreement was clear that:

"Notwithstanding articles 6.1 and 6.2, the Joint Review Panel is not required by this agreement to make any determinations as to:

- a. the validity of Aboriginal or treaty rights asserted by a participant or the strength of such claims;
- b. the scope of the Crown's duty to consult an Aboriginal group; or
- c. whether the Crown has met its respective duties to consult or accommodate in respect of rights recognized and affirmed by section 35 of the *Constitution Act, 1982*."

In the Jackpine Decision<sup>120</sup> the Joint Review Panel created to review the application for the Jackpine Mine Expansion Project issued an interlocutory decision in which it concluded that it did not have jurisdiction to consider whether the Crown had complied with its

<sup>115</sup> Osum Oil Sands Corp., Taiga Project, ERCB Reasons for Decision on *Notice of Question of Constitutional Law*, dated July 17, 2012.

<sup>116</sup> *Ibid* at 7.

<sup>117</sup> *Cold Lake First Nations v Alberta (Energy Resources Conservation Board)*, 2012 ABCA 304 at para 6.

<sup>118</sup> Agreement to Establish a Joint Review Panel for the Jackpine Mine Expansion Project, online: Canadian Environmental Assessment Agency <<http://www.ceaa.gc.ca/050/documents/52084/52084E.pdf>> at s6.1.

<sup>119</sup> *Ibid* at s6.2.

<sup>120</sup> Jackpine Mine Expansion Project, Joint Review Panel decision, (26 October 2012).

obligation to consult with aboriginal peoples.

Some commentators have suggested the Osum and Jackpine ERCB decisions reflect some sort of reluctance or some sort of improper “avoidance of treating the duty to consult like other questions of constitutional law.”<sup>121</sup> In contrast, I would suggest that the ERCB correctly identified the difference arising from the presence of a private (non-Crown) applicant and correctly understood the limitations expressly placed on the Joint Review Panel. To date, the Courts appear to agree.

The Athabasca Chipewyan First Nation and the Métis Nation of Alberta Region 1 sought leave to appeal the Jackpine Decision. Again, the Alberta Court of Appeal denied leave to appeal.

“While the jurisdictional issues raised by the applicants are interesting in the abstract, it is not appropriate to grant leave to appeal as the answers to those questions would not affect the outcome of this hearing. The Joint Review Panel ‘ . . . is not required . . . to make any determination as to . . . whether the Crown has met its respective duties to consult . . . ’. The Joint Review Panel has clearly decided not to engage this issue, at least at this stage of its proceedings. It is entitled to do that.”<sup>122</sup>

An application for leave to appeal to the Supreme Court of Canada was denied.<sup>123</sup>

#### *i. New Alberta Legislation*

Effective June 17, 2013, the newly-minted Alberta Energy Regulator replaced the ERCB. Section 21 of the *Responsible Energy Development Act*, SA 2012, c R-17.3 makes it clear that the new Regulator shall have neither the duty to consult nor the duty to access Crown

consultation:

“Crown consultation with aboriginal peoples.

The Regulator has no jurisdiction with respect to assessing the adequacy of Crown consultation associated with the rights of Aboriginal peoples as recognized and affirmed under Part II of the *Constitution Act, 1982*.”

Certain commentators have decried the removal of duty to consult issues from the regulatory forum. For example Nigel Bankes has commented:

Will this lead to certainty and expedited approval or more delays and uncertainty? I suspect that different readers will have different responses but I have a hard time seeing how this is going to lead to improved and integrated decision making. In fact it looks like a single window for everything except decisions which engage the duty to consult.<sup>124</sup>

While there is certainly a legitimate *policy* debate to be had around whether or not an Energy Regulator ought to play a role in carrying out and/or assessing the adequacy of the duty to consult, the *legal* debate has been settled. The Supreme Court of Canada has made it clear that “[t]he duty on a tribunal to consider consultation and the scope of that inquiry depends on the mandate conferred by the legislation that creates the tribunal.”<sup>125</sup> The Alberta legislation clearly takes up this invitation and clearly states the mandate conferred (and not conferred) on the Alberta Energy Regulator. Absent a challenge to the legislation, the Legislature’s answer is determinative.<sup>126</sup>

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<sup>121</sup> See J. Promislow, “Irreconcilable?: The Duty to Consult and Administrative Decision Makers”, 26 CJALP 251 at 266.

<sup>122</sup> *Métis Nation of Alberta Region 1 v Joint Review Panel*, 2012 ABCA 352 at para 20.

<sup>123</sup> *Athabasca Chipewyan First Nation v Energy Resources Conservation Board acting in its capacity as part of the Joint Review Panel, Joint Review Panel*, 2013 CanLII 18847.

<sup>124</sup> Nigel Bankes, “Bill 2 the Responsible Energy Development Act and the Duty to Consult” Ablawg (19 November 2012), online: Ablawg <[http://ablawg.ca/wp-content/uploads/2012/11/Blog\\_NB\\_Bill2\\_Duty\\_to\\_Consult\\_Nov2012.pdf](http://ablawg.ca/wp-content/uploads/2012/11/Blog_NB_Bill2_Duty_to_Consult_Nov2012.pdf)>.

<sup>125</sup> *Rio Tinto Alcan*, *supra* note 2 at para 55.

<sup>126</sup> In *Rio Tinto*, the Court expressly left open the question of whether government conduct that can trigger the duty to consult includes legislative action at para 44. Thus, whether legislation setting up the regulatory process can be

Notwithstanding the clear statement of legislative intent, there still appear to be transitional and definitional issues to be addressed regarding the proper scope of constitutional questions. On October 18, 2013, Fort McKay First Nations was granted leave to appeal the decision of the Alberta Energy Regulator in relation to the Dover/Brion Project.<sup>127</sup> The Court of Appeal (per. Justice Frans Slatter) granted leave on two questions:

- a. Did the Energy Resources Conservation Board or the Alberta Energy Regulator commit any reviewable error of law or jurisdiction in the assessment of the type of constitutional questions they could or should consider under their general jurisdiction over issues of law, or the *Administrative Procedures and Jurisdiction Act*?, and if so
- b. Did any such reviewable error in defining the scope of the constitutional issues have any reviewable impact on the ultimate approval of the project by the Alberta Energy Regulator?<sup>128</sup>

This decision clearly would have been one to watch closely as it may have provided further clarity on the AER's role in considering aboriginal rights and treaty issues under the *Administrative Procedures and Jurisdiction Act*.<sup>129</sup> However, as this article was being concluded, the First Nation and project proponent reached a settlement agreement, and the pending appeal was discontinued. The definitional issues under the Alberta legislation will remain unresolved—for now.

As we have seen (in the discussion of the B.C. legislation in *Rio Tinto*), the legislative treatment

of “constitutional questions” in the legislation may not always be drafted in a manner that expressly contemplate (and clarifies) the role of the Regulator in relation to the duty to consult. However, given the very clear statement in section 21 of REDA, the role of the Alberta Energy Regulator in relation to the duty to consult appears to be settled.<sup>130</sup>

### Conclusion

In the discussion of the duty to consult and the role of the Energy Regulator, what is required is not a single universal, one-size-fits-all answer, which has proven elusive in both the Aboriginal law and the Regulatory/administrative law context. Instead, what is required is a greater awareness of (i) the different legal contexts for Aboriginal groups (non-treaty, historic treaty or modern treaty); (ii) the resulting differences in the purpose and scope of the Crown's duty to consult in each legal context; and (iii) the specific mandate assigned to the Energy Regulator in the legislation that creates it.

Energy Regulators may be required to carry out the duty to consult, the duty to adjudicate the adequacy of consultation carried out by others, both of these roles, or neither. Two key indicia are the power to consider questions of law, and the remedial powers granted to the Energy Regulator. Guidance may be had from examining how the regulatory process fits into the overall decision-making process. In addition, the role of the Energy Regulator may differ depending on the nature of the Applicant appearing before it—in particular whether the Applicant is a Crown agent or a private party. The various combinations and permutations of these various factors does not lend itself to universal

challenged in this way remains to be determined.

<sup>127</sup> Dover Operating Corp. Application for a Bitumen Recovery Scheme Athabasca Oil Sand Area, 2013 ABAER 014, August 6, 2013. *Fort McKay First Nation v Alberta Energy Regulator*, 2013 ABCA 355. It should be noted that the decision of the AER is subject to the further approval of the Lieutenant Governor in Council.

<sup>128</sup> Leave to appeal was denied on two other issues raised by the Applicants, which were characterized in the Applicants' Notice of Appeal as follows:

- Whether the Tribunal erred in law or jurisdiction by reason of its narrow interpretation of its inquiry jurisdiction and its remedial jurisdiction to consider and respond, respectively, to cumulative environmental effects; and
- Whether the Tribunal erred in law or jurisdiction by reason of the process through which it purported to make findings respecting project impacts on constitutionally protected Treaty rights of the Fort McKay First Nation.

<sup>129</sup> RSA 2000, c A-3.

<sup>130</sup> The issue of the duty to consult may still be judiciable in relation to the (as yet still forthcoming) decision of the Lieutenant Governor in Council—similar to the scenario in *Brokenhead Ojibway*, *supra* note 95

solutions that apply to all Energy Regulators. Instead, the key message is one that should be familiar to administrative law practitioners—it depends. It depends on the statute, the nature of the application and even the nature of the Applicant. This diversity is not to be decried, but embraced, as Energy Regulators find their proper place in the decision-making process and their proper role in respect of the Crown's duty to consult Aboriginal peoples. ■

# THE 2013 NORTH AMERICAN NATURAL GAS MARKET – A YEAR IN REVIEW

*Gordon Pickering\**

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## **Introduction**

The North American natural gas market in 2013 was a hot topic news item again, as it has taken center stage in a variety of media outlets over the last several years. While a portion of the industries gas news in the previous year for 2012 was highlighted by low natural gas prices that were generally between \$2 and \$3 per MMBtu, in 2013 the focus was less on prices as price recovered and more on other issues, including the matter of Liquefied Natural Gas (LNG) exports from North America. Of course, the two items are related in that the recent natural gas abundance resulting from the on-going development of shale gas resources is the driving force behind lower natural gas prices, which together with the supply abundance has created opportunities for serving new markets, all while reshaping the market on this continent.

A brief overview of the new phenomenon of supply abundance, which is relevant for both the United States and Canada, is in order. As late as 2008, conventional wisdom held that North American natural gas production would have to be supplemented increasingly by imports of LNG, natural gas in a different form that was necessitated apparently by domestic

natural gas supply resource decline, impending shortages, and resulting in higher commodity prices. Far less conspicuously, in places as such as Texas in the Barnett gas shale and in other places in the mid-continent, Louisiana, Oklahoma and the U.S. northeast region in Pennsylvania's Marcellus basin, a 'technological break-through' was taking place that would transform the industry. Through a combination of horizontal drilling and hydraulic fracturing, existing technologies were combined together and continually improved, with dramatic results markedly increasing drilling and production efficiencies, reducing costs, and in the end bringing substantial new volumes of natural gas from 'unconventional' supply sources to the market. When Navigant released its American Clean Skies natural gas supply assessment in mid-2008, domestic gas production from shale began to overtake imported LNG as the new gas supply of choice in North America.<sup>1</sup> This set off what has been a 'new era' of gas supply development characterized by ramping rates of shale gas production growth that have shown no let-up since and have resulted in overall gas supply abundance, even surpluses, over the last several years.

Although the bulk of the gas shale development so far has occurred in the U.S., for several

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<sup>1</sup> Navigant first quantified the rapidly expanding development of natural gas from shale in 2008, in its ground-breaking report for the American Clean Skies Foundation, *North American Natural Gas Supply Assessment* (4 July 2008), online: Navigant Consulting <[http://www.navigant.com/-/media/WWW/Site/Insights/Energy/NCI\\_Natural\\_Gas\\_Resource\\_Report.ashx](http://www.navigant.com/-/media/WWW/Site/Insights/Energy/NCI_Natural_Gas_Resource_Report.ashx)>.

reasons it is the key driver of overall North American gas market developments. First, because the North American natural gas market is a truly interconnected, continental market (if not a part of a global gas market at this point) significant natural gas developments in one region can and do have impacts in other regions. As will be discussed later, for example, the sheer magnitude of the new gas production in the Marcellus Shale centred in Pennsylvania and West Virginia has already caused changes in gas flows that can be seen, so far, as far away as in the U.S. Southeast, as well as north, up into Canada, dramatically affecting flow patterns and changing the historically developed relationships and contracting patterns that were developed over a half century or more. Further, Canada itself has discovered that it, too, has huge shale gas and tight gas resources of its own that are poised for development as the shale gas revolution takes hold in Canada. The sheer size of the new resources that have been unlocked in both countries are what is most notable, setting off a new 'golden age' of natural gas in North America and leading to the prospects for and the ensuing debate over serving new markets with North American natural gas in the form of LNG via exports to anxiously awaiting international buyers around the world.

## UNITED STATES

### Gas Supply

The importance of the shale gas revolution in the U.S. would be difficult to overestimate. Shale gas resources are almost totally behind the large increases in recoverable natural gas resource estimates (as well as the increases in actual production). Not only are entirely new gas resource plays being discovered, and then

brought into production, but as additional data from producing gas plays is obtained over time, the resource estimates of those active plays have generally ended up being raised in an on-going series of resource re-assessments. Estimates for the Marcellus play, for example, have risen from 50 Tcf in 2008<sup>2</sup> to 369 Tcf in June 2013,<sup>3</sup> as Marcellus production has increased from virtually nothing to over 10 Bcfd (at the wellhead) in the same period.<sup>4</sup> By the end of 2013, Marcellus wellhead production actually exceeded 12 Bcfd, constituting 17 per cent of U.S. Lower 48 wellhead production.<sup>5</sup> All in a span of only five years.

For the U.S. as a whole, the natural gas resource estimate released by the Potential Gas Committee in April 2013 put total U.S. recoverable gas resources at 2,689 Tcf, up 24 per cent from 2,170 Tcf in its April 2011 release. At the U.S. 2013 demand level of 26 Tcf,<sup>6</sup> that is enough natural gas to meet demand for over 100 years. Notably, the PGC's shale gas estimate increased a full 50 per cent (from 687 Tcf to 1,073 Tcf), while its non-shale resource estimate increased also but only 9 per cent (from 1,484 Tcf to 1,616 Tcf). The most recent estimate of U.S. shale gas recoverable resources adopted by the U.S. Federal Government is actually even slightly higher than the PGC estimate, at 1,161 Tcf.<sup>7</sup>

### U.S Market Dynamics 2013

Driven by the increases in gas resource estimates, total dry U.S. natural gas production reached an all-time high in 2013, increasing from 2012 levels by about 1 per cent to 24.3 Tcf, which exceeded the pre-shale gas U.S. high of 21.7 Tcf in 1973 by 2.6 Tcf.<sup>8</sup> Because of constantly improving drilling

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<sup>2</sup> Terry Endelger & Gary G. Lash, "Marcellus Shale Play's Vast Resource Potential Creating Stir in Appalachia" (May 2008), online: American Oil & Gas Reporter <<http://www.aogr.com/index.php/magazine/cover-story/marcellus-shale-plays-vast-resource-potential-creating-stir-in-appalachia>>.

<sup>3</sup> *World Shale Gas and Shale Oil Resource Assessment*, prepared by Advanced Resources International, Inc. as exhibit to *Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States*, U.S. Energy Information Administration, June 2013, Attachment C, Table A-1.

<sup>4</sup> LCI Energy Insight data.

<sup>5</sup> *Ibid.*

<sup>6</sup> US Energy Information Administration, Natural gas consumption by End Use (28 February 2014), online: EIA <[http://www.eia.gov/dnav/ng/ng\\_cons\\_sum\\_dcu\\_nus\\_a.htm](http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm)>.

<sup>7</sup> See ARI Report, *supra* note 3, Attachment C, Table A-1.

<sup>8</sup> US Energy Information Administration (EIA) data.

efficiencies, the increase in production came despite much lower gas drilling rig counts in 2013, following a steady shift to oil-directed drilling over 2012<sup>9</sup> -- to a point where today, the U.S. is the largest gas producer in the world, having passed Russia in 2011. And on the back of the technology break-through for shale gas, the U.S. has even more recently experienced a renaissance of oil production where it has passed Saudi Arabia in 2013 to become the largest oil producer in the world.<sup>10</sup> Over just the last five years, total U.S. gas production has grown a full 21 per cent increasing from 20.1 Tcf to 24.3 Tcf, and the situation has not conceivably peaked. In fact, Navigant forecasts U.S. gas production to increase an additional 24 per cent to 29.9 Tcf in 2020 (about 3 per cent CAGR), and then to increase a further 18 per cent to 36.1 Tcf in 2035 (about 1 per cent CAGR).

Consider further the following. Over the course of 2013, shale production levels (at the wellhead) increased 14 per cent, from 30.9 Bcfd in January to 35.3 Bcfd in December.<sup>11</sup> A key driver of this increase was the Marcellus Shale, where production increased 50 per cent, from 8.4 Bcfd to 12.5 Bcfd (at the wellhead) at the end of the year to comprise 35 per cent of total shale gas production.<sup>12</sup> Another facet of the growth was that gas production from liquids rich plays increased as producers shifted drilling away from dry gas plays. A prime example of such production is the Eagle Ford shale in south Texas, where gas production grew 39 per cent during 2013, from 3.3 Bcfd in January to 4.5 Bcfd in December.<sup>13</sup> Shale gas' share of total U.S. production (at the wellhead) increased 5 percentage points over the year, from 43 per cent to 48 per cent of Lower 48 total wellhead production.<sup>14</sup> For North America as a whole,

we estimate unconventional gas made up 35 per cent of dry gas production in 2013, and we forecast more importantly for unconventional gas to grow to 58 per cent of the overall supply mix in 2035.<sup>15</sup>

U.S. total natural gas consumption in 2013 grew modestly by about 2 per cent, increasing from 25.4 Tcf in 2012 to reach 26.0 Tcf. Compared to 2012, the residential, commercial and industrial sectors each increased consumption (by 21 per cent to 5.0 Tcf, by 13 per cent to 3.3 Tcf, and by 3 per cent to 7.4 Tcf, respectively), while the electric generation sector somewhat surprisingly decreased consumption by 10 per cent. Despite its decrease, electric generation remained the largest gas consuming sector in 2013, with its 8.1 Tcf comprising about 31 per cent of total natural gas consumption. Electric generation gas demand was down in 2013 as a result of higher gas prices than the banner year of 2012 (when electric generation gas demand increased 20 per cent), but over the prior eight years from 2003 through 2011 electric generation demand grew at an average CAGR of 4.98 per cent per year and by 47.5 per cent over the period.

The decrease in natural gas consumption for power generation in the U.S. was driven by the generation resource mix moving from 37 per cent coal and 30 per cent gas in 2012 to a place in 2013 where coal fired generation actually made up 39 per cent of the electric generation sector and natural gas' share dropped to 27 per cent of the electric generation market in 2013.<sup>16</sup> The rebound in coal generation in 2013 is a function of the continuing competitive price structure between the two fuels in some U.S. regions. It is also a function of the delay of various carbon taxes in the U.S. that are

<sup>9</sup> Navigant estimates average U.S. gas rig counts of 556 in 2012 and 383 in 2013, based on Baker Hughes data.

<sup>10</sup> See "Today in Energy: U.S. expected to be largest producer of petroleum and natural gas hydrocarbons in 2013", [www.eia.gov](http://www.eia.gov), October 4, 2013.

<sup>11</sup> *Supra* note 4

<sup>12</sup> *Ibid* 12.5 Bcfd Marcellus wellhead production versus 35.3 Bcfd Lower 48 wellhead shale gas production in December 2013.

<sup>13</sup> *Ibid*.

<sup>14</sup> *Ibid*, 30.9 Bcfd shale wellhead production versus 71.1 Bcfd Lower 48 wellhead production in 2012; 35.3 Bcfd versus 73.7 Bcfd in 2013.

<sup>15</sup> Gordon Pickering & Rebecca Honeyfield, "North American Natural Gas Market Outlook, Fall 2013" (1 December 2013) at p 3, online: Navigant Consulting Perspectives <<http://www.navigant.com/insights/library/energy/2013/ng-outlook-fall-13/>> .

<sup>16</sup> *Supra* note 8.

expected to increase gas-fired generation compared to coal-fired generation should they occur. In any event, the rebound in coal's share of the generation mix in 2013 is not assured to continue and may be viewed in hindsight as an anomaly. Looking back over a somewhat longer period, coal has not regained close to its market share of the electric generation sector before the large drop in gas prices in 2012, when coal made up 42 per cent of the electric generation market and gas was at 25 per cent of the electric generation market in 2011. In looking forward, planned coal-fired generation retirements as of January 2014 are expected to total 34,000 MW, which is an increase from mid-2012 forecasts of planned retirements of about 31,500 MW, and should again result in the eventual growth of gas fired generation at the expense of coal in the electric generation sector in the U.S.<sup>17</sup> Our firm's forecast of the future generation mix (like other's I have seen at least directionally) is for coal to decrease from a 39 per cent market share in 2014 to a 35 per cent market share for coal in 2018, as large amounts of coal-fired generation retire.

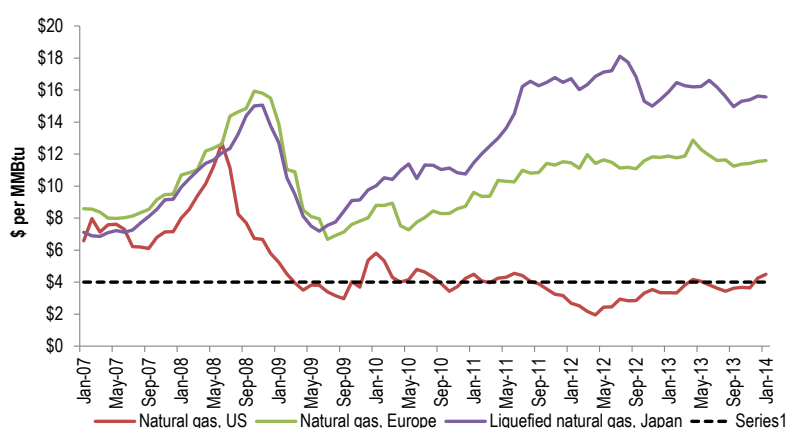
The annual average spot price in the U.S. national market measured at Henry Hub was up 35 per cent in 2013, to \$3.73/MMBtu versus \$2.75/MMBtu on the same basis in 2012.

This, I might point out, was still 7 per cent below annual prices in 2011 that were \$4.00/MMBtu.<sup>18</sup> To put current U.S. gas prices in perspective, \$3.73 is actually 58 per cent below the average annual spot price in 2008 of \$8.86/MMBtu, before the shale revolution. Notably, this level is also well below gas prices in other parts of the world, such as in Europe with gas prices averaging \$11.79/MMBtu and in Japan with gas prices averaging \$16.02/MMBtu in 2013<sup>19</sup> (see figure 1 below). Of course, it is this huge price differential between domestic U.S. and North American natural gas prices, due to gas supply abundance, and prices in the international market that are yet to experience the impact of shale gas and are in some cases pegged to high priced oil, that creates opportunities for economically-driven LNG exports – a matter that became increasingly important in the U.S. gas market in 2013.

#### U.S. LNG Exports to Global Gas Markets

There was significant activity at the U.S. Department of Energy's Office of Fossil Fuels (DOE) in 2013 regarding applications for authorization to export LNG to Non-Free-Trade nations.<sup>20</sup> The year started off with the DOE taking scores of comments from interested parties on its LNG Export Study,

**Figure 1:** US natural gas prices have declined by 2/3 since 2008; other regions have increased creating wide divergence in global gas prices



Source: World Bank Commodity Price Data

<sup>17</sup> Energy Velocity data.

<sup>18</sup> *Supra* note 8.

<sup>19</sup> World Bank Commodity Price Data. See figure 1 above.

<sup>20</sup> Approval of exports to countries with a Free Trade Agreement with the U.S. is almost ministerial and automatic.

the second and final piece of which (the NERA Report) was released in December 2012.<sup>21</sup> Key findings of the NERA Report were that LNG exports will create net economic benefits to the country, and that the global modelling used in the report actually showed that many assumed levels of LNG exports (i.e. the higher ones) used in the initial part of the LNG Export Study (the EIA Report) would not be economically feasible in the global market, and therefore would lead to invalid results should they be assumed as parameters in a North American model. These findings in favour of LNG exports were subsequently relied on by DOE as it started to move forward with its backlog of LNG export authorization applications. While the last prior LNG export authorization had been granted almost two years earlier (and in fact was the first non-FTA authorization and export approval by the DOE and was supported in the application by Navigant),<sup>22</sup> within three months after the comment period on the LNG Export Study ended the DOE issued its next authorization, to Freeport LNG, in May 2013.<sup>23,24</sup> Following the Freeport authorization, DOE followed with additional approvals for Lake Charles LNG (August), Cove Point LNG (September),

and Freeport Expansion LNG (November). On February 11, 2014, the DOE approved Cameron LNG, LLC's application to export up to 1.7 Bcfd to non-FTA countries for a period of twenty years. The DOE has now issued non-FTA LNG export authorizations for about 8.5 Bcfd in aggregate.

At present, the remaining non-FTA LNG export applications total about 26 Bcfd from almost twenty projects, with 11.6 Bcfd having been filed in 2013 by eight projects. DOE has created an "order of precedence" for its review of the applications, which is basically the order of filing of the respective DOE applications (provided that a project had received approval from FERC to utilize FERC's pre-filing process for site approval by December 5, 2012). The next five applications up for review, according to the DOE's order of precedence are: i) Jordan Cove Energy Project, 0.8 Bcfd from Oregon; ii) Oregon LNG, 1.0 Bcfd from Oregon; iii) Corpus Christi Liquefaction, 1.8 Bcfd from Texas; and iv) Exceleerate Liquefaction Solutions, 1.4 Bcfd from Texas; Carib Energy (USA) LLC, 0.03 Bcfd from Texas (see figure 2 below). With respect to the ultimate level

Figure 2:

#### U.S. DOE Order of Precedence for Next Five Applications

Current Processing Position	Company
1	Jordan Cove Energy Project, L.P. (West Coast)
2	LNG Development Company, LLC (Oregon LNG) (West Coast)
3	Cheniere Marketing, LLC (Corpus Christie) (Gulf Coast)
4	Exceleerate Liquefaction Solutions I, LLC (Gulf Coast)
5	Carib Energy (USA) LLC (Gulf Coast)

There are currently 20 countries with a Free Trade Agreement, the only one of which is a major LNG-importing nation being South Korea.

<sup>21</sup> *Macroeconomic Impacts of LNG Exports from the United States*, NERA Economic Consulting, December 2012. The initial component of the LNG Export Study was performed by EIA, U.S. Energy Information Administration, *Effect of Increased Natural Gas Exports on Domestic Energy Markets*, January 2012.

<sup>22</sup> DOE/FERC Order No 2961, *Opinion and Order Conditionally Granting Long-Term Authorization to Export Liquefied Natural Gas From Sabine Pass LNG Terminal to Non-Free Trade Agreement Nations*, May 20, 2011.

<sup>23</sup> DOE/FERC Order No 3282, *Order Conditionally Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From The Freeport LNG Terminal on Quintana Island, Texas to Non-Free Trade Agreement Nations*, May 17, 2013.

<sup>24</sup> For an analysis of FERC's LNG export approvals, see Gordon Pickering and J. Van Horne, "Why a Market Solution to the LNG Export Question Makes Sense" *NG Market Notes* (June 2013), online: Navigant Consulting, <<http://www.>

of LNG export capacity that is likely to be built in North America, and regardless of the volumes ultimately permitted by the DOE, Navigant's view is that U.S. exports will likely be in the 8 to 10 Bcfd range, much less than the total application volumes or possibly even the volume ultimately given approval by the DOE. A number of factors contribute to this view, including the fact that substantial capital requirements are necessary for each project, the significant commercial contractual issues to be resolved, and that the existence of global competition from existing large LNG exporters such as Qatar and Australia as well as emerging potential projects around the globe from places like East Africa and other areas in the Middle East, and indeed the emergence of competition through development of global shale resources, especially in emerging market regions around the world.<sup>25</sup>

Of the five projects that now hold U.S. non-FTA LNG export approvals, only the Cheniere Corporation's Sabine Pass Liquefaction facility has also received the necessary Federal Energy Regulatory Commission (FERC) site approval and is under construction. The first phase of that project, comprised of Trains 1 and 2 of about 0.55 Bcfd each, is over 50 per cent completed as of December 2013. Construction work on Trains 3 and 4 (Phase 2) is also under way, and is about 20 per cent completed.

Many significant LNG commercial arrangements have already been signed by the LNG export projects. Publicized agreements from 2013 include: those between Cameron LNG and Tokyo Electric Power Company, GDF Suez, Mitsubishi, and Mitsui; those between Freeport LNG and Osaka Gas, Chubu Electric Power, BP, and Toshiba; and between Sabine Pass and Centrica. Prior publicized agreements include: those between Sabine Pass and Total, GAIL, Kogas, Gas Natural Fenosa, and BG;

those between Cove Point LNG and Gail and Sumitomo; and between Main Pass LNG and Petronet. As North American supplies become increasingly important to overseas buyers and by so doing moves the market towards a truly "global market" the likelihood is that the market will be characterized by ongoing weakening of oil-indexed gas pricing that is now dominant in both Asia and Europe. Some weakness regarding 'oil-indexing' has already shown up in contract negotiations and renegotiations that have already taken place in Europe, as has been reported by several 'insiders' spoken to at a recent European gas conference. Such fundamental changes in the global gas landscape will be one of the major developing stories in the years to come, but first became apparent in the market in 2013.

## CANADA

### Gas Supply Resources

Similar to the case of U.S. recoverable gas resource estimates, Canadian gas resource estimates have shown large increases recently. A key component of the increase is the new estimate of gas resources for the Montney formation in Alberta and British Columbia. A November 2013 joint report of the National Energy Board, the British Columbia Oil & Gas Commission and Ministry of Natural Gas Development, and the Alberta Energy Regulator that singled out a review for the Montney, increased the estimate of recoverable natural gas in the Montney from 108 Tcf to 449 Tcf, which the report's website noted would leave the revised Montney formation alone able to meet Canadian demand for 145 years.<sup>26</sup> Another key driver is the latest detailed estimate of shale play resources as contained in the ARI assessment commissioned by the EIA and released in May 2013. The ARI Report put Canadian shale gas recoverable resources at

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[navigant.com/insights/library/energy/2013/ng-market-notes-june-2013/](http://navigant.com/insights/library/energy/2013/ng-market-notes-june-2013/).

<sup>25</sup> *Supra* note 15.

<sup>26</sup> *The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta*, Energy Briefing Note, National Energy Board, B.C. Oil & Gas Commission, Alberta Energy Regulator and B.C. Ministry of Natural Gas Development, November 2013. Note that although portions of the Montney Formation are shale gas, the formation as a whole is generally classified as unconventional but non-shale due to the variety of its characteristics, including tight gas. See FAQs at <http://www.neb-one.gc.ca/clf-nsi/rnrgynfmrtn/nrgyrprt/ntrlgs/ltmptntlmtntnyfmrtn2013/ltmptntlmtntnyfmrtn2013fq-eng.html>.

573 Tcf, including the Horn River at 133 Tcf, the Liard Basin at 158 Tcf, the Duvernay at 113 Tcf, and the Cordova Embayment at 20 Tcf.<sup>27</sup> Adding the 449 Tcf for the Montney and the 573 Tcf for shale gas to the 422 Tcf for non-shale and non-Montney natural gas resources as most recently estimated by the NEB,<sup>28</sup> yields estimated total Canadian recoverable resource at 1,444 Tcf, a staggering 465 years of Canadian demand at the 2012 level of 3.1 Tcf per year total gas consumption level used by the NEB.

### Canadian Market Dynamics in 2013

Canadian total marketed gas production decreased about 1.5 per cent in 2013, dropping from 5.05 Tcf to 4.97 Tcf. The drivers were a two per cent decrease in Alberta, from 3.48 Tcf to 3.41 Tcf, coupled with a three per cent increase in British Columbia, from 1.29 Tcf to 1.33 Tcf.<sup>29</sup> The most active areas of developing production were the Montney formation, with 2.4 Bcfd (2.05 Bcfd in B.C. and 0.35 Bcfd in Alberta), and the Horn River basin, with 0.5 Bcfd, as of the third quarter of 2013.<sup>30</sup>

With the increase in shipments of Marcellus gas to U.S. markets, exports of Canadian natural gas into the U.S. fell 12 per cent from 2012 to 2013 (measured over the first 10 months of the year), dropping from 5.77 Bcfd to 5.05 Bcfd.<sup>31</sup> This is yet another shining example of the 'game changer' aspects brought about by a technical breakthrough that has taken over the integrated North American gas industry over the last five years.

In 2013, the annual average spot price (at AECO) was up 28 per cent in 2013, to \$3.06/

MMBtu<sup>32</sup> versus \$2.39/MMBtu in 2012, but still 17 per cent below the same price in 2011 of \$3.67/MMBtu. Obviously some equilibrium adjustments are still occurring in the Canadian gas industry as they are in the U.S., with gas price in North America well below gas prices in other parts of the world, such as in Europe where as we have said gas prices averaged \$11.79/MMBtu and in Japan where prices averaged \$16.02/MMBtu in 2013.<sup>33</sup> It is also worth noting that Canadian prices are below U.S. gas prices in most markets due to the particular high levels of supply abundance and the fact that supply in some instances is stranded as a result of changing market dynamics affecting Canadian gas supply.

### Canadian LNG Export Developments

As in the U.S., there was significant activity in Canada in 2013 related to LNG exports. While the NEB had approved two export applications over the prior two years, totalling 1.55 Bcfd,<sup>34</sup> in 2013 the NEB approved four LNG export applications, totalling 13.1 Bcfd.<sup>35</sup> A consistent theme in the NEB's approval orders was the recognition that the sheer magnitude of Canadian natural gas resources, together with the new North American market dynamics driven by increasing U.S. natural gas production, making it important for Canada to find new markets to support further development of its domestic gas industry.<sup>36</sup>

At present, the remaining gas export applications to the NEB total 10.7 Bcfd from six projects, all filed since August 2013, and all but 1.4 Bcfd from the west coast of Canada. Two of the applications, by Jordan Cove LNG and Oregon LNG Marketing, are by

<sup>27</sup> See ARI Report, *supra* note 3, Attachment A.

<sup>28</sup> See *Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035*, National Energy Board, November 2013 at 49.

<sup>29</sup> *Supra* note 4.

<sup>30</sup> *Ibid.*

<sup>31</sup> *Supra* note 8.

<sup>32</sup> Platts data.

<sup>33</sup> World Bank Commodity Price Data (Pink Sheet), online: <<http://econ.worldbank.org/WBSITE/EXTERNAL/EXTDEC/EXTDECPROSPECTS/0,,contentMDK:21574907-menuPK:7859231-pagePK:pagePK:64165401-piPK:64165026-theSitePK:476883,00.html>>.

<sup>34</sup> Kitimat LNG (1.3 Bcfd) in 2011 and BC LNG (.25 Bcfd) in 2012.

<sup>35</sup> LNG Canada (3.2 Bcfd), Pacific Northwest LNG (2.7 Bcfd), Prince Rupert LNG (2.9 Bcfd), WCC LNG (4.0 Bcfd) and Woodfibre LNG (.29 Bcfd)

<sup>36</sup> See e.g., NEB, *Letter Decision for WCC LNG Ltd*, OF-EI-Gas-GL-W156-2013-01 01 (16 December 2013).

proposed U.S. LNG liquefaction projects that will rely upon Canadian natural gas feedstock, to be delivered in large part through the long standing existing interconnected pipeline grid that exists in the region and supporting the projects. These applications are an indication of the abundant endowment of natural gas in Western Canada, and are an example of the type of new market the provinces of B.C. and Alberta are seeking in order to bolster their own gas industries.

### Infrastructure Developments

Another important set of 2013 natural gas developments are those affecting the TransCanada Corporation, one of North America's largest gas pipeline companies and a long standing and important artefact of the Canadian gas industry. Several events relate to TransCanada's mainline, with capacity to move 7 Bcfd from Empress, Alberta to Dawn, Ontario and farther eastward. In 2013, the NEB approved new reduced mainline rates proposed in a major rate restructuring application aimed at improving the competitiveness of the mainline given its decreasing throughput, which for some time had been causing rate increases on the system. The new rates that were set from Empress to Dawn delivery are \$1.42/GJ, down from the old rate of \$2.58/GJ, and based on throughput expected to increase from 3.9 Bcfd to 4.3 Bcfd. A second important development in 2013 occurred as TransCanada announced in August that it will move forward with its Energy East project, a project that would convert about 1 Bcfd of Mainline capacity from natural gas to oil transportation and is viewed by TransCanada as an attempt to 'utilize' otherwise surplus capacity on its Mainline.

Other events impacting other parts of TransCanada's business in Canada include: i) selection by Progress Energy's Pacific Northwest LNG in January 2013 to build the

Prince Rupert Gas Transmission project to move 2 Bcfd of natural gas from the North Montney area to the LNG project on Lelu Island near Prince Rupert; ii) execution of a contract in August with Progress Energy for about 2 Bcfd of firm gas transportation service that will help move forward its NOVA Gas Transmission Ltd. subsidiary's North Montney mainline project; iii) proposed enhancement by FortisBC of the Southern Crossing Pipeline linking Spectra Energy's system at Kingsvale to Kingsgate, that will provide additional capacity for natural gas to get from the Spectra system in B.C. onto TransCanada's GTN system to serve the U.S. Northwest and California markets and possibly to serve export projects in Oregon.

### Demand Expansion Policy

Consistent with the NEB Short-Term Deliverability report<sup>37</sup> showing Canadian natural gas production in a "holding pattern" with minimal new drilling activity as producers wait for natural gas prices to increase, finding new or expanded markets for natural gas has been a newly developed yet now entrenched new policy direction in Western Canada. In July 2013, the provinces of British Columbia and Alberta announced the formation of a Working Group led by senior energy officials to develop recommendations related to energy exports, towards opening new export markets for B.C. and Alberta.<sup>38</sup> The shared goals of B.C. and Alberta in creating the Working Group are to expand export opportunities for oil, gas and other resources, and to create jobs and strengthen the provincial economies through the development of the oil and gas sector. The Working Group reported to Premieres Clark and Redford at the end of 2013 with recommendations and an action plan. The creation of the Working Group indicates the clear policy support for gas resource development.<sup>39</sup> In a similar vein, Alberta executed in October 2013 a *Framework Agreement on Sustainable Energy Development*

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<sup>37</sup> National Energy Board, *Short-Term Canadian Natural Gas Deliverability*, 2013-2015, May 2013 at 1.

<sup>38</sup> See British Columbia/Alberta Deputy Ministers Working Group "Terms of Reference", (26 July 2013), online: BC government <<http://www.reuters.com/article/2013/07/15/ks-tallgrass-energy-idUSnBw156415a+100+B5W20130715>>.

<sup>39</sup> The formation of the Working Group follows the release in February 2012 of the clearly stated, progressive and unique policy of the province of British Columbia, as part of the overall Province Jobs Plan, in favour of accelerated

with China to strengthen ties in energy development, energy investment and energy trade.

### 2013 in Summary

The phenomenon of North American natural gas abundance due to the shale revolution continued in 2013. U.S. production advanced to a new all-time high, and the U.S. DOE moved forward with four LNG non-FTA export approval orders (with a fifth Cameron LNG approved early in 2014). The abundance of natural gas that is evidenced by the prolific growth in shale gas production, such as the 50 per cent growth in Marcellus Shale production during 2013, has only been further enhanced by updated resource studies indicating about 2,700 Tcf of recoverable gas in the U.S. and over 1,400 Tcf in Canada. The dependability of shale gas production as a result of its abundance, as well as its reduced exploration risk as compared to conventional gas resources, creates the potential to improve the alignment between supply and demand and mitigate the industry's "boom and bust" cycles, which will in turn tend to lower price volatility, a long standing issue for the gas industry that has hampered increased market penetration. Thus, the vast shale gas resource not only has the potential capability to support a much larger demand level that has yet been seen in North America, but at prices that are less volatile and indeed at lower overall price levels than were thought possible just a few years ago.

An informed market view is that U.S. and Canadian domestic supply is abundant to such a degree that it will support domestic market requirements as well as export demand for LNG shipped from North America. Indeed, the new environment of gas abundance not only enables but is in need of new market demand that will offer the potential for a steady, reliable baseload

market to underpin future supply development. As evidenced by the many LNG export applications filed, industry players recognize the opportunity that currently exists due to the current differentials in world gas prices. The opportunity for LNG exports from U.S. and from Canada, however, will yield benefits far beyond the gas industry, providing benefits to the overall economy through multiplier effects that create additional indirect economic stimulus impacts from the billions of dollars in new investment and through job creation.

The magnitude of shale gas production, particularly in Eastern U.S., started to cause dramatic and fundamental changes in traditional gas flow patterns across North America in 2013.<sup>40</sup> A prime indicator of this dynamic is the change in supply patterns to the U.S. Northeast market, where Marcellus Shale production has displaced supplies from both the U.S. Gulf region and the Western Canadian Sedimentary Basin, resulting in reductions of market share by a 28 per cent share (from a 50 per cent share to a 22 per cent share, a 56 per cent reduction) and a 15 per cent share (from a 22 per cent share to a 7 per cent share, a 68 per cent reduction), respectively, since 2008. Canada's National Energy Board has recently recognized these new market dynamics in *Energy Future 2013*, referencing increasing production from the Marcellus that has reduced the need for Canadian exports to the U.S. Northeast, a market traditionally served in part by WCSB gas,<sup>41</sup> and in fact has led to increasing imports into Canada from the U.S.,<sup>42</sup> that is expected only to continue to increase in the future. I believe additional competitive pressure on Western gas supplies will result from Marcellus and Utica Shale gas displacing traditional supplies in the U.S. Midwest market, which could be Canadian WCSB gas or U.S. Rockies gas that could ultimately put pressure upon Canadian supplies further west

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development of its natural gas resources. In its Natural Gas Strategy document, as well as a complementary Liquefied Natural Gas Strategy, the province presented its goals of building three LNG export facilities by 2020, and estimated an accompanying increase in gas production from the current level of 1.2 Tcf per year to over 3 Tcf per year in 2020. Further, the Strategy included the diversification of its gas markets, including development of supplies to meet new gas demand in North America. With these natural gas and LNG strategies, the province has clearly been planning for a significant growth of its natural gas industry, from upstream production through midstream transportation and processing, to further growth of downstream end-use markets.

<sup>40</sup> See e.g. Rebecca Honeyfield, "Shifting Gas Flows" *NG Market Notes* (9 September 2013), online: Navigant Consulting, <<http://www.navigant.com/insights/library/energy/2013/ng-market-notes---september-2013/>> .

<sup>41</sup> See National Energy Board, *Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035- An Energy Market Assessment*, (November 2013), at 15.

<sup>42</sup> *Ibid* at 54.

as the U.S. Rockies gas seeks new markets. An example of changing flow patterns across North America is that the Rockies Express Pipeline executed a binding precedent agreement in July 2013 to move up to 200 MMcfd of a large Utica Shale producer's gas westward to midcontinent markets. REX noted that it anticipates becoming "truly bi-directional" as it provides takeaway capacity from the Utica Shale.<sup>43</sup> The initial signs of other flow pattern changes across North America also started to become clearer in 2013 – driven by new shale gas development.

With increasing pressure on Western gas supplies due to the remarkable development of Eastern U.S. resources, the need for new markets for Western gas will be even more dramatic as the prolific unconventional gas resources in British Columbia are developed, creating what I would suggest will be a groundswell of commercial opportunities, particularly in Western Canada. I furthermore expect this market change that developed clearly in 2013 to continue to develop over the foreseeable future as Asian markets discover the benefits and alignment of LNG supply from North America with Asian growth in gas demand.<sup>44</sup> ■

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<sup>43</sup> Rockies Express Pipeline LLC, Press Release, "Shale to Shining Shale Strategy" (15 July 2013), online: Reuters <<http://www.reuters.com/article/2013/07/15/ks-tallgrass-energy-idUSnBw156415a+100+BSW20130715>>.

<sup>44</sup> This expectation would be further supported by associated gas that is likely to be produced from California's prolific Monterey Shale oil resource as it develops. According to EIA's Annual Energy Outlook 2013 Assumptions (Table 9.3), the Monterey oil shale play is the largest in the country, with 13.7 billion barrels of oil, actually exceeding the sum of the Bakken (8.0 billion barrels) and the Eagle Ford (5.2 billion barrels).

# FOSTERING COMPETITION AMONGST REGULATED LDCS: THE DUTCH EXPERIENCE

*Dr. Hugo Schotman\**

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## Introduction

**R**ate setting for local distribution companies (LDCs) is often a labor-intensive task for both regulators and LDCs. In Canada, most regulators use some form of rate of return regulation, which involves rate setting mechanism that require very complex and involved cost and performance tracking. One way to avoid this somewhat heavy involvement of the regulator might be to follow the Dutch approach of using *price-cap regulation with yardstick competition*.

In this approach the regulator simply calculates what the average level of the reported cost per customer class is amongst the appropriate LDC peer group (which includes both operational and capital expenditure costs and a base level return on investment component) and only authorizes rates per customer that will recover this average level of cost.

Those LDCs that can outperform this average cost level (i.e. have lower costs) can then earn a higher rate of return. Similarly, those who do not meet the cost performance standard will earn less than the base allowed return on investment.

This form of rate setting maximizes the freedom and efficiency of the regulated entities and is used in some European countries such as the United Kingdom and the Netherlands. Below we will outline how this kind of regulation is being implemented in the Netherlands.

## The Dutch Context

To understand the Dutch approach you first must understand the structure of the regulated energy services sector in the Netherlands. The Netherlands is 250 times smaller than Canada in surface area, but with fully half the population of Canada the country requires a dense electricity and gas distribution network to be able to provide the needed energy services. These services are delivered by eight LDCs through about eight million electricity and seven million gas connections<sup>1</sup>. These LDCs operate both electricity and gas networks with the three largest LDCs serving more than 90 per cent of the electricity and gas connections. The electricity and gas networks are separately regulated and the LDCs are at least legally unbundled and cannot act as a supplier of the commodity.

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<sup>1</sup> Netbeheer nederland, online: Energie Trends 2012 (in Dutch) <[www.netbeheernederland.nl/Content/Files/file/EnergieTrends2012.pdf](http://www.netbeheernederland.nl/Content/Files/file/EnergieTrends2012.pdf)>.

The Netherlands has one energy regulator (the Authority for Consumers and Markets<sup>2</sup>), whose independence is guaranteed by European directives.<sup>3</sup> This (national) regulator is responsible for implementing directly binding European regulation and the Dutch Electricity and Gas Acts<sup>4</sup> and regulations based on these acts. The *Electricity Act* and *Gas Act* prescribe the implementation of price-cap regulation for LDCs.

### Price-Cap Regulation with Yardstick Competition

The basis for both revenue and price-cap regulation is that LDCs are incentivized to *decrease* their cost level with respect to the previous cost level by an efficiency gain or productivity increase (X-factor). The costs of an LDC can then only increase at a rate equal to the increase in the consumer price index (CPI), or whatever measure of inflation has been chosen, less the identified X-factor.<sup>5</sup> In price-cap regulation<sup>6</sup> with yardstick in the Netherlands, the regulator sets a maximum consumer tariff per customer class for a certain time period (the “price period”, usually three to five years). An example of a customer class is a consumer connection with a certain capacity.

The maximum consumer tariff is based on

the efficient cost level of the electricity or gas distribution sector. This efficient level is equal to the average costs per unit output of the sector plus a *general productivity increase*, which was until the current price period (2011-2013) based on the average cost reduction in a previous price period.<sup>7</sup> The X-factor reflects the reduction in costs or the productivity increase an *individual* LDC has to achieve to reach the efficient level at the end of a price period. The average X-factors for the next price period (2014-2016) are 4.7 per cent for the electricity<sup>8</sup> and 6.7 per cent for the gas<sup>9</sup> sector.

The X-factor thus leads to a decrease in allowed revenues to a level that is equal to a return for the efficient costs at the end of a price period. This includes a market conform rate of return for investments, because in the Dutch system both operational and capital costs are included in the regulation. The market conform rate of return is based on an estimate of the weighted-average-cost-of-capital (WACC) for a certain price period.<sup>10,11</sup> The WACC enters the regulation in three ways: historical values are used to calculate the general productivity increase, the WACC for the current price period (6.2 per cent) is used to calculate the efficient costs at the beginning of the new price period ( $TI_{2014}$ )<sup>12</sup> and the WACC for the next price period (3.2 per cent) is used to estimate the efficient costs at the end of the next

<sup>2</sup> Authority for Consumers and Markets, online: ACM <<https://www.acm.nl/en/>>.

<sup>3</sup> Directives 2009/72/EC (electricity) and 2009/73/EC (gas).

<sup>4</sup> Electricity Act 1998: [http://wetten.overheid.nl/BWBR0009755/geldigheidsdatum\\_16-09-2013](http://wetten.overheid.nl/BWBR0009755/geldigheidsdatum_16-09-2013), Gas Act: [http://wetten.overheid.nl/BWBR0011440/geldigheidsdatum\\_16-09-2013](http://wetten.overheid.nl/BWBR0011440/geldigheidsdatum_16-09-2013). These Acts implement the EU energy directives and national energy policies.

<sup>5</sup> In a formula:  $TI_E = (1 + CPI - X) \times TI_B$ , with  $TI_E$  the total revenues (or efficient costs) at the end of the price period and  $TI_B$  the total revenues (or efficient costs) at the beginning of the price period.

<sup>6</sup> The main difference with revenue-cap regulation is that in price-cap regulation the total income is sensitive to changes in the volume of a certain customer class.

<sup>7</sup> In the new decisions for the next price period (2014-2016), the general productivity increase is based on a longer period (from 2005), because a sector-wide cost rise in the previous price period has led to negative X-factors (and thus rising prices) in the current price period.

<sup>8</sup> Autoriteit Consument en Markt, Toezicht regionale netbeheerders elektriciteit: X-factoren regionaal netbeheer elektriciteit (2014-2016) (in Dutch), online: ACM <<https://www.acm.nl/nl/onderwerpen/energie/elektriciteit/regulering-regionale-netbeheerders/x-factoren-regionaal-netbeheer-elektriciteit-2014-2016/>>.

<sup>9</sup> Autoriteit Consument en Markt, Toezicht regionale netbeheerders gas: X-factoren regionaal netbeheer gas (2014-2016) (in Dutch), online: ACM <<https://www.acm.nl/nl/onderwerpen/energie/gas/regulering-regionale-netbeheerders/x-factoren-regionaal-netbeheer-gas-2014-2016/>>.

<sup>10</sup> Dan Harris, Bente Villadsen & Francesco Lo Passo, *Calculating the Equity Risk Premium and the Risk-free rate* (26 November 2012), online: The Brattle Group <<https://www.acm.nl/nl/download/bijlage/?id=10972>>.

<sup>11</sup> Dan Harris, Bente Villadsen & Francesco Lo Passo, *The WACC for the Dutch TSOs, DSOs, water companies and the Dutch Pilotage Organisation* (4 March 2013), online: The Brattle Group <<https://www.acm.nl/nl/download/bijlage/?id=10974>>.

<sup>12</sup> *Supra* note 5 (Compare with  $TI_B$  in the formula).

price period ( $TI_{2016}$ ).<sup>13,14</sup>

Price-cap regulation with yardstick competition creates a strong incentive for cost reduction, as an LDC that is able to beat the targetted efficiency level (the yardstick) may keep the profit. This incentive is mainly due to the fact that the tariffs are fixed for the price period (and the incentive increases if the price period is extended). The cost efficiency of the whole sector is increased by this competition, so that in the next price period the consumers will benefit via lower tariffs. The method is a relatively light-handed form of regulation that minimizes the administrative burden for both the utilities and the regulator, as the utilities do not have to report individual investments and the regulator is not concerned with how the utilities decrease their costs.

An important prerequisite for yardstick competition is that LDCs have comparable costs for a certain customer class. This is not the case if there are regional differences between cost situations of the LDCs. Examples of possible regional cost differences in the Netherlands include LDCs whose systems might have more water crossings and LDCs that face higher local taxes or other such fees. If a regional difference in the Dutch approach leads to substantial higher costs per customer class for that individual LDC and these costs are considered to be “structural and non-controllable” by the LDC, then the LDC is allowed a higher tariff per customer class.<sup>15</sup> At present, despite attempts by LDCs to claim certain of these regional costs differences the only (recognized)

regional difference that LDCs have been able to substantiate to the regulator’s satisfaction are some local taxes.<sup>16</sup>

### Efficiency Versus Quality

As indicated above, price-cap regulation with yardstick competition leads to strong incentives for cost efficiency.<sup>17</sup> Surveys in the Netherlands have shown that the total costs of the distribution networks, which includes both operational and capital costs, have decreased substantially:<sup>18</sup> 4.6 billion Euros for electricity (from 2000-2011) and 2.4 billion Euros for gas (from 2001-2011). For the new price period from 2014 to 2016, the costs of electricity distribution will decrease with 8 per cent and for gas with 6.5 per cent.

There is a fear however, that the strong incentive to decrease costs might lead to underinvestments by LDCs in attempts to keep their costs down. A large survey in 2009, ordered by the regulator, did not find proof that LDCs have shown a tendency to underinvest in previous years<sup>19</sup>, a conclusion confirmed by a more recent report.

Still, to help guard against possible underinvestment, two mechanisms have been introduced to balance efficiency and quality of the energy infrastructure. Electricity LDCs are not only subject to an X-factor, but also to a quality factor known as the Q-factor. The Q-factor should reflect the (non-financial) performance of an LDC<sup>20</sup> and leads to a bonus

<sup>13</sup> *Supra* note 5 (Compare with  $TI_E$  in the formula).

<sup>14</sup> Autoriteit Consument and Markt, *Methodebesluit regionaal netbeheer elektriciteit* (2014-2016) (in Dutch), online: ACM <<https://www.acm.nl/nl/download/publicatie?id=12002>>; Autoriteit Consument and Markt, *Methodebesluit regionaal netbeheer gas* (2014-2016) (in Dutch), online: ACM <<https://www.acm.nl/nl/download/publicatie?id=12003>>.

<sup>15</sup> This does not lead to an overall rise in consumer tariffs, only to a shift of income from the LDCs that do not have these extra costs to the LDC that does.

<sup>16</sup> Since the transfer of high voltage lines to the transmission operator, water crossing longer than 1 km are no longer substantial. The density of the network, with possible higher costs for rural areas, has been under discussion for a long time, but has not been proven to be a regional difference yet.

<sup>17</sup> It also leads to a level-playing field, in which LDCs have the same costs per unit output.

<sup>18</sup> Tariefregulering in retrospectief: Inventariserend en structurerend feitenonderzoek, Berenschot, 11 April 2012 (in Dutch).

<sup>19</sup> Investerings in energienetwerken onder druk? Een beoordeling van het reguleringskader, PriceWaterhouseCoopers, October 2009 (in Dutch).

<sup>20</sup> The Gas Act prescribes a quality indicator for gas, but this was set to zero by the regulator, as the most important attribute of distributing the commodity is not the quality of the commodity, but the safety of the network and it was deemed not prudent to include safety in the yardstick competition.

(or a malus) for an LDC if its performance is better (or worse) than its peers.<sup>21</sup> Moreover, for both electricity and gas LDCs there is a policy rule that prescribes which processes LDCs must have implemented for managing the quality and the capacity of the networks and that obliges the LDCs to report about these processes to the regulator every two years.

### Innovation and 'Specials'

In general, competition between companies is thought to lead to innovation.<sup>22</sup> Some people therefore argue that yardstick competition between utilities in the Netherlands leads to innovation within the electricity and gas distribution sectors. This seems to be true as far as the innovation is aimed at cost efficiency improvements, but it is less clear for broader forms of innovation that would benefit the energy system at large.<sup>23</sup> Both to address the risk of underinvestment mentioned above and to facilitate innovation beyond just cost control, a new instrument for 'special' investments by LDCs was included in the *Electricity Act* and *Gas Act* from July 2011.

The idea of the instrument is to give LDCs more security about their return on investment for *some* investments rather than within the system of yardstick competition. Investments that need this extra security are 'special' investments: investments that are in the public interest, but that do not get a sufficient reward in the yardstick competition, either because other LDCs are not doing them (or at least not on the same scale) or because they do not generate (sufficient) output gains compared to the costs. A 'special' investment will always get a separate remuneration within a price period, which means it is kept outside the regulated asset base that is used for yardstick competition. After that, the LDC will keep receiving a separate remuneration as long as the investment is still considered 'special'.

### Conclusions

Price-cap regulation with yardstick competition has led to significant efficiency gains in the Dutch electricity and gas distribution sectors. It is a form of regulation with a relatively low administrative burden and in which some (regional) differences between utilities can be accounted for. Given the success of this form of rate setting in the Netherlands and other European jurisdictions, it has the potential to improve the cost efficiency performance of North American LDCs.

Recently a new instrument was introduced in the Netherlands to provide extra financial security for 'special' investments. The drawback of such an instrument is that it takes investments out of the yardstick competition and thus potentially weakens the incentive system. Moreover, it requires an additional administrative burden, which makes the regulation less light-handed. However, the instrument is not yet used by the LDCs, perhaps indicating that the regulation is working fine and that, at the moment, no extra measures are needed. ■

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<sup>21</sup> In a formula:  $TI_E = (1 + CPI - X + Q) \times TI_B$ .

<sup>22</sup> See for example Mike Cleland et al, "Economic Regulation and the Development of Integrated Energy Systems" (September 2012) ICES Literacy Series - Paper No. 3.

<sup>23</sup> Autoriteit Consument en Markt, "Zienswijze en consultatie: Consultatie over innovatie (in Dutch), online: ACM <<https://www.acm.nl/nl/publicaties/publicatie/7009/Consultatie-over-innovatie/>>.

# NORTHERN GATEWAY: ROUND NO.1

Rowland J. Harrison, Q.C.\*

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The release of the *Report of the Joint Review Panel for the Enbridge Northern Gateway Project*,<sup>1</sup> on December 19, 2013 will likely prove to be a watershed moment in the history of Canada's federal pipeline regulation regime. The range and complexity of the issues raised by the Project<sup>2</sup> presented unprecedented challenges for the Review Panel, compounded by unparalleled expectations for participation in the hearing process. The submission of the Report to the Governor in Council also initiated the recently revised process for approval of federal pipeline projects directly by Cabinet, rather than by the National Energy Board. Perhaps not surprisingly, a challenge to the Report has been filed in the Federal Court of Appeal.<sup>3</sup>

The mandate of the Joint Review Panel (JRP), as defined in the Joint Review Panel Agreement between the National Energy Board and the Minister of the Environment (JRPA),<sup>4</sup> was to conduct a review, under the *Canadian Environmental Assessment Act, 2012*,<sup>5</sup> of the

environmental effects of the project and to make a recommendation to the Governor in Council on whether the project should be approved, based on the Panel's determination, under the *National Energy Board Act*,<sup>6</sup> of whether the project is in the public interest. The JRPA defined the Project for this purpose to include two proposed pipelines between Bruderheim, Alberta and Kitimat, British Columbia and a terminal at Kitimat including tanker berths and storage tanks. Marine transportation of oil and condensate within a defined assessment area was also included.<sup>7</sup>

The three-member Panel was appointed on January 20, 2010. The application for the necessary approvals for the Project was filed in May 2010. In August and September 2010, the Panel conducted sessions to receive comments on the scope of the issues to be considered in the hearing. The Panel Hearing Order was issued on May 5, 2011 and oral hearings commenced in January 2012. Final arguments were heard

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<sup>1</sup> See <http://gatewaypanel.review-examen.gc.ca/clf-nsi/dcmnt/rcmndtnsrprt/rcmndtnsrprt-eng.html>. The Report is in two volumes: Volume 1, *Connections* and Volume 2, *Considerations* (together referred to herein as the *Gateway Report* or Report). Page and Volume references herein are to the printed edition of the Report.

<sup>2</sup> The Northern Gateway Project is a proposed oil pipeline from a point near Edmonton, Alberta to Kitimat, British Columbia, a distance of 1,177 kilometers. There are two parallel pipelines proposed in the same right-of-way, a 36-inch pipeline to carry an average of 525,000 barrels per day of petroleum west for export by ship and a 20-inch pipeline to carry an average of 193,000 barrels per day of condensate east. Condensate is used to thin petroleum products for transport by pipeline. The Project is described in the *Gateway Report*, *supra* note 1, Volume 1, section 1.1 and Volume 2, section 1.1.

<sup>3</sup> *Forestethics Advocacy, Living Oceans Society and Raincoast Conservation Foundation v. Attorney General of Canada, Minister of the Environment, National Energy Board and Northern Gateway Pipelines Limited Partnership*, Federal Court of Appeal A-56-14, filed January 17, 2014. Since the date of writing, applications for judicial review have been filed by several other groups, as well as applications for judicial review by First Nations groups on the ground, *inter alia*, that the review process has not complied with the Crown's duty to consult where Aboriginal rights may be affected.

<sup>4</sup> Dated 4 December 2009, as amended 3 August 2012. See Appendix 4 of the *Gateway Report*, *supra* note 1.

<sup>5</sup> *Canadian Environmental Assessment Act*, SC 2012, c 19 (*CEA Act 2012*).

<sup>6</sup> RSC 1985, c N-7, as amended 6 July 2012 (*NEB Act*).

<sup>7</sup> *Gateway Report*, *supra* note 1 Volume 1 s 1.1.

in May and June 2013.<sup>8</sup> As noted, the Panel Report was released on December 19, 2013.

In its Report, the Panel described concerns regarding the project in four main areas:

- The likelihood and consequences of malfunctions and accidents;
- Effects of construction and routine operations on the environment;
- Economic soundness, costs, benefits, design, construction, and operations; and
- Effects of the project on society, culture, and Aboriginal people.<sup>9</sup>

The Panel concluded that several matters that it had been urged by many people to consider in its assessment were beyond the scope of the Project and outside its mandate. These included both “upstream” oil development effects and “downstream” refining and use of the products. With respect to upstream effects, the Panel found that there was not “a sufficiently direct connection between the project and any particular existing or proposed oil sands development or other oil production activities to warrant consideration of the effects of these activities.”<sup>10</sup> The effects of downstream emissions “were outside our jurisdiction,” although the Panel did consider emissions from construction and operation of the project, as well as from tankers in Canadian territorial waters.

The Panel summarized its role in the following terms:

Some people said economic development like the Enbridge Northern Gateway Project could harm society and the environment, while others told us a strong economy was necessary to sustain and enhance environmental and social values. They all recognized the linkages

among people, economy, and environment, and that these are all aspects of a shared ecosystem.

Our task was to recognize these connections. We weighed and balanced them to answer the fundamental question: Would Canada and Canadians be better or worse off if the project goes ahead?<sup>11</sup>

In the Panel’s view, the question was to be answered by weighing the potential burdens and benefits of the Project “as they affect the environment, society, and economy at the local, regional, and national levels”:

These three dimensions of the public interest interact and overlap, and we considered them in an integrated manner.

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In our view, environmental protection and economic activity that benefits society are important aspects of the determination of the public interest. When we speak of environmental protection, we consider all facets of the environment including humans, animals, plants, our geographic surroundings, and areas of cultural significance. In this context, there is no differentiation between the environment and the economy. They are inextricably connected and are integral aspects of the public interest.<sup>12</sup>

In approaching its task, the Panel stated that it had considered the evidence “in a careful and precautionary manner,”<sup>13</sup> which it was required to do under the JRPA.<sup>14</sup> Noting that the Project could operate for 50 years or more, the Panel added that sustainable development was an important factor in the environmental assessment and in considering the public interest:

The project would have to meet today’s needs

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<sup>8</sup> *Gateway Report*, *supra* note 1 Volume 2 App 3.

<sup>9</sup> *Gateway Report*, *supra* note 1 Volume 1 at 18.

<sup>10</sup> *Ibid* at 17.

<sup>11</sup> *Ibid* at 1.

<sup>12</sup> *Ibid* at 74.

<sup>13</sup> *Ibid* at 11.

<sup>14</sup> JRPA, *supra* note 4 at para 6.3.

without compromising the ability of future generations to meet their needs.<sup>15</sup>

The Panel concluded that Canada and Canadians would be better off with the Northern Gateway Project than without it. It therefore recommended that the Project be approved, subject to 209 conditions.

The Panel found that project effects, in combination with cumulative effects, would likely be significant for certain populations of woodland caribou and grizzly bear, due to uncertainty over the effectiveness of proposed mitigation to control access and achieve the goal of no net gain, or net decrease, in linear feature density. The Panel recommended, however, that the Governor in Council find that these significant effects would be justified in the circumstances.<sup>16</sup>

As the Panel noted, the Northern Gateway Project would traverse extensive areas in Alberta and British Columbia that Aboriginal groups use for traditional activities and practices and for exercising Aboriginal and treaty rights. The marine areas that would be potentially impacted by the Project are also used for traditional purposes and claimed as part of traditional territories.<sup>17</sup> Accordingly, the Panel paid particular attention to consultation with Aboriginals, Aboriginal participation in the review process and the effects of the Project on Aboriginals. The Panel concluded that, during construction and routine operations, there would not be a significant adverse effect on the ability of Aboriginal groups to continue to use lands, waters or resources for traditional purposes or to maintain, pursue and strengthen their traditional and cultural activities.<sup>18</sup> In the unlikely event of a large oil spill, adverse effects on Aboriginal groups would not be permanent and widespread.

The Panel found that, with Northern Gateway's commitments and compliance with the Panel's conditions, "Northern Gateway can effectively continue to engage and learn from Aboriginal groups that chose to engage, and address issues raised by Aboriginal groups throughout the project's operational life."<sup>19</sup>

With respect to the Crown's duty to consult, the Panel noted the position of the Government of Canada that "it will rely on the Joint Review Panel process to the extent possible to assist in fulfilling its legal duty to consult Aboriginal groups."<sup>20</sup> The federal government had stated that, if project-related issues that required Crown consultation could not be addressed through the Panel's process, it would consult directly with the potentially-affected Aboriginal groups.<sup>21</sup> The Canadian Environmental Assessment Agency noted that it was responsible for coordinating the federal government's consultation with Aboriginal groups and that it had appointed the Crown Consultation Coordinator for that purpose. The Panel added that it offered "no views in relation to the consultation activities undertaken by the Government of Canada to date, or any future consultation that it will undertake, with Aboriginal groups."<sup>22</sup>

The Northern Gateway Project review process attracted widespread participation. Specifically, 206 parties registered as interveners, with a further 12 as Government Participants. The Panel heard evidence and oral statements from more than 1,500 participants in 17 communities. It also received more than 9,000 letters of comment. Remote participation was enabled through video and telephone links.<sup>23</sup>

The Panel was required by the JRPA to conduct its review "in a manner which will facilitate the participation of the public and Aboriginal

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<sup>15</sup> *Gateway Report*, *supra* note 1 Volume 1 at 11.

<sup>16</sup> *Ibid* at paras 72-73.

<sup>17</sup> *Gateway Report*, *supra* note 2 Volume 2 at 26.

<sup>18</sup> *Ibid* at 50.

<sup>19</sup> *Ibid* at 41.

<sup>20</sup> *Ibid*.

<sup>21</sup> *Ibid* at 36.

<sup>22</sup> *Ibid* at 41.

<sup>23</sup> *Gateway Report*, *supra* note 2 Volume 1 at paras 14-15.

peoples...”<sup>24</sup> Consequently, the Panel’s process set minimal requirements for participation. However, the resulting extent of participation in the review process was criticized by many observers, including the federal Minister of Natural Resources,<sup>25</sup> resulting in legislative amendments to restrict participation in future proceedings under both the *CEA Act*<sup>26</sup> and the *NEB Act*.<sup>27</sup> Henceforth, participation is restricted to those who are “directly affected” or who have “relevant information or expertise.”

The Panel Report must now be considered by the Governor in Council. Under the *CEA Act, 2012*, the Governor in Council must decide whether the Project is likely to cause significant adverse environmental effects and, if so, whether those effects can be justified in the circumstances.<sup>28</sup> Under the *NEB Act* as amended in 2012, the Governor in Council must decide, with reasons, whether to direct the NEB to issue a certificate of public convenience and necessity for the Project.<sup>29</sup> His decision must be made by mid-June.<sup>30</sup> However, the Governor in Council can refer the matter back to the Panel<sup>31</sup> and may extend the time limit by “any additional period or periods of time.”<sup>32</sup> This is an as yet untested process and will be watched closely by both project proponents and other interested parties.

Meanwhile, application has been made to the Federal Court of Appeal for orders, *inter alia*, prohibiting the Governor in Council from making the decisions or orders required by the *CEA Act* or the *NEB Act* arising from the Panel’s Report or “taking any other action to enable the Project to proceed...”<sup>33</sup> The application was made by Forestethics Advocacy, the Living Oceans Society and the Raincoast

Conservation Foundation, all of which were intervenors in the JRP hearings. The principal grounds are that the Panel failed to meet the requirements of the *Species at Risk Act*<sup>34</sup> and that it considered irrelevant evidence by considering upstream economic benefits while refusing to hear evidence with respect to or to consider the induced upstream environmental impacts of the Project.<sup>35</sup>

Whatever the final outcome, the *Report of the Joint Review Panel for the Enbridge Northern Gateway Project* is a significant milestone in the development of the regulatory framework. Its comprehensiveness in addressing the wide range of complex issues that the Gateway Project presents is likely to establish the Report as a touchstone for future assessments of major projects. The Panel’s discussion of the public interest – with its focus on the core question of whether Canada and Canadians would be better or worse off if a project were approved and with its emphasis on balancing benefits and burdens in answering this question – will provide helpful guidance in future proceedings. The emphasis on integrating the three elements of environment, society and economy – as interconnected aspects of the public interest – provides a valuable model for assessing major resource development projects that present increasingly complex issues and challenges for the regulatory process. ■

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<sup>24</sup> *RPA*, *supra* note 4 at para 6.4.

<sup>25</sup> See for example, Natural Resources Canada, *An Open Letter from the Minister on energy markets and the regulatory process* (9 January 2012) online: Natural Resources Canada <<http://www.nrcan.gc.ca/media-room/news-release/2012/1911>>.

<sup>26</sup> *Supra* note 5, s 2(2).

<sup>27</sup> *Supra* note 6, s 55.2.

<sup>28</sup> *CEA Act*, *supra* note 5 ss 31, 52.

<sup>29</sup> *Supra*, note 6 s 54.

<sup>30</sup> Future Governor in Council decisions on *National Energy Board* recommendations for pipeline approvals must be made within three months, although that period may be extended.

<sup>31</sup> *NEB Act*, *supra* note 6 s 53.

<sup>32</sup> *Ibid* s 54(3).

<sup>33</sup> *Notice of Motion*, *supra* note 3 at para 1(k).

<sup>34</sup> *Species at Risk Act*, SC 2002, c 29.

<sup>35</sup> *Notice of Motion*, *supra* note 3 at para 34.

# ENBRIDGE GAS DISTRIBUTION NEW BRUNSWICK DECISION

*David MacDougall\**

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The Court of Appeal of New Brunswick issued its Decision in *Enbridge Gas New Brunswick Limited Partnership et al vs. the Attorney General in and for the province of New Brunswick*, 2013 NBCA 34, on May 3, 2013. This decision was an appeal from a Decision of the New Brunswick Court of Queen's Bench (Madam Justice Paulette Garnett) dated August 23, 2012. The Enbridge parties (hereafter Enbridge) sought a declaration from the New Brunswick Queen's Bench Trial Division that Section 4(1) of Regulation 2012-49 under the *Gas Distribution Act*, S.N.B. 1999, c. G-2.11 was invalid on the basis that it was *ultra vires* the Lieutenant-Governor in Council of the province of New Brunswick.

Enbridge Gas New Brunswick Limited Partnership is a regulated public utility which holds a general franchise for the distribution of natural gas in New Brunswick. In January 2012, the New Brunswick Legislature amended the *Gas Distribution Act* ("GDA"). Section 52(5)(a) of the amended GDA provides that the New Brunswick Energy and Utilities Board ("EUB") "shall adopt the methods or techniques prescribed by regulation" when fixing rates and tariffs for the sale of natural gas in New Brunswick. The New Brunswick Lieutenant-Governor in Council ("LGIC") made a regulation, the rates and tariff regulation, which came into effect on April 16, 2012 (the "Regulation"). Section 4(1) of the *Regulation* directed the EUB to apply the cost of service method or technique but also directed the EUB to apply a "revenue to cost ratio not exceeding 1.2:1" for any class of customers to which the

cost of service method or technique was to be applied. Section 4(1) further provided that the rates and tariffs determined according to the cost of service method or technique are not to exceed those rates that would have been fixed had the EUB adopted the pre-existing market based method or technique for rate setting which generally previously prevailed in the province of New Brunswick.

Enbridge sought a declaration that section 4(1) of the *Regulation* was *ultra vires* the LGIC. Madam Justice Garnett phrased the question for the lower Court as follows: "Does the *Regulation* fall within the scope of the authorization provided by the statute and is it consistent with the general purposes of the governing statute?" Madam Justice Garnett found that sections 52 and 95 of the GDA were broad enough to authorize section 4(1) of the regulation, and she therefore found that section 4(1) was within the statutory authority of the LGIC. The Court of Appeal stated that in coming to her decision Madam Justice Garnett "held that section 52(5)(a) must be construed broadly." The Court of Appeal also noted that Section 95 of the GDA which authorized the LGIC to adopt a regulation prescribing the methods the EUB must adopt when approving or fixing rates was for the purposes of the appeal assumed to have no substantive difference from section 52(5)(a) of the GDA.

On the appeal, the province of New Brunswick contended that the phrase "methods or techniques prescribed by regulation" should be interpreted broadly to cover all relevant

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considerations when it comes to fixing rates. Such a broad interpretation would embrace matters such as the revenue to cost ratio. Enbridge argued that the phrase “methods or techniques” has a limited meaning which embraces recognized methods for fixing rates.

The Court of Appeal relied upon the modern approach to statutory interpretation in noting that section 52(5)(a) of the GDA could not be read in isolation. The Court of Appeal stated that the provision must be read in the context of the legislative scheme surrounding the EUB’s obligation to set “just and reasonable” rates. Aided by the presumption of “internal coherence” and the presumption against “absurd results” the Court’s contextual analysis led it to the conclusion that it was not the New Brunswick’s Legislature’s intention that Section 52(5)(a) would be interpreted as broadly as the province contended.<sup>1</sup> Rather to the contrary, the Court of Appeal found that the phrase “methods or techniques” has a technical meaning; one that is restricted in nature and in keeping with section 52 as a whole. This led to the Court of Appeal’s ultimate finding that the directive set out in section 4(1) of the *Regulation*, requiring the EUB to apply a maximum revenue to cost ratio, was *ultra vires* the regulation-making authority of the LGIC.

The Court of Appeal concluded that in reviewing the GDA and the *Regulation* it was clear that the legislature was addressing itself to two known “methods or techniques” for fixing rates: (1) cost of service; and (2) marked based. Thus, the court held that the phrase “methods or techniques” could not be reasonably interpreted to include the right of the LGIC to direct the EUB to apply, for example, a designated cost to service ratio.

The Court of Appeal allowed the appeal in part and declared that part of section 4(1) of the *Regulation* dealing with the “revenue to cost ratio” was beyond the regulation-making

authority of the LGIC.

The Court of Appeal Decision continued a lengthy line of Canadian jurisprudence which holds that actions undertaken by the LGIC must be consistent with the intention of the overriding legislation under which they are made. Notably in the regulation of technical industries such as electricity and natural gas, industry terminology and terms of art are, as noted by the Court of Appeal, better given the meaning “best understood by those who must interpret and apply the legislation within a regulated industry.” Interestingly in this latter regard, although not determinative in the result, two Justices of the Court of Appeal noted that it was “at least arguable that the interpretive issue at hand could have been taken directly to the [EUB].” The two Justices did conclude that it was best to leave that issue for another day, but stated that in their view the Court was left with the task of interpreting “technical” terms with which “the courts of the province cannot be presumed to have a familiarity.”

In the end result, the Court of Appeal concluded that the GDA as it read after the 2012 amendments continued to leave it to the EUB to determine what the revenue to cost ratio should be, and thus the directive in this regard in the *Regulation* was *ultra vires* the regulation-making authority of the LGIC. ■

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<sup>1</sup> With respect to the issues of “internal coherence” and “absurdity”, the Court of Appeal noted in particular certain further statutory directives found in Subsections 52(5)(b), (c) and (d) of the GDA, and stated that if the province’s broad interpretation were to be adopted the LGIC could have simply relied on paragraph 52(5)(a) to adopt a regulation that also incorporated the matters in paragraphs (b)-(d). The Court of Appeal concluded in this regard that “it makes no sense to take the first of the four fetters and interpret it in a manner that eliminates the need to impose the remaining three.”

# TRILLIUM WIND: CAN DEVELOPERS SUE WHEN GOVERNMENT WIND PROJECTS ARE CANCELLED?

*Gordon E. Kaiser, FCI Arb\**

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Across Canada, provincial governments, either directly or through purchasing organizations or government-owned utilities, have been aggressively purchasing wind generation over the last five years.

What happens when the government changes its mind and cancels the project? That situation recently faced Trillium Wind Power Corporation, a Toronto-based developer building offshore wind turbines in Lake Ontario. The company had applied to lease provincial land under Ontario's wind power policy and had been granted Applicant of Record status by the Ministry of Natural Resources.

That status gave Trillium three years to test the wind power. After that, the company could proceed with an environmental assessment and obtain authorization to operate the wind farm.

Trillium subsequently notified the Ontario Ministry of Natural Resources that the company intended to close a \$26 million financing for the project. On the same day the Government of Ontario issued a moratorium on offshore wind development including developers like Trillium that had Applicant of Record status.

The government issued a press release stating that the projects were canceled pending further scientific research.

Trillium brought a number of claims against the Ontario government seeking \$2 billion in damages. The claims included breach of contract, unjust enrichment, negligent misrepresentation, misfeasance in public office and intentional infliction of economic harm.

The province brought a motion to strike the Trillium Statement of Claim on the basis that it did not disclose a reasonable cause of action. The motion was successful. The motion judge found that the government decision to close the wind farms was a policy decision and therefore immune from suit.

The motion judge also found that the fact that Trillium had been granted Applicant of Record status did not amount to a contractual relationship between Trillium and the government. The motion judge concluded that the claim should be struck because it was plain and obvious that the claim could not succeed at trial.

Trillium appealed on two grounds: first,

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misfeasance in public office was a tenable claim as a matter of law; and second, the claim had been adequately pleaded. The Ontario Court of Appeal agreed.<sup>1</sup> It was not clear that the claim of misfeasance in public office would necessarily fail. Moreover, Trillium had properly pleaded that the province's actions were taken in bad faith for improper purpose. The Court also found that the government's decision was made to harm Trillium specifically. While the Court of Appeal did agree with the motions judge that a government decision involving political factors was immune, there was an exception for irrational acts of bad faith.

The facts in this case were unique. It was clear that the Trillium announcement disclosing new financing triggered the government action. And, as the court concluded, the government specifically targeted Trillium.

This is an important case for wind developers. Government contracting for wind is now common. And it is not unusual for governments to change these programs. Nor is it unusual for developers to incur substantial costs in processing their applications.

Successful claims against governments that cancel projects are rare but may increase.

This is the first time the tort of misfeasance in public office has found its way into the energy sector. The tort can be traced back to the English case of *Ashby v. White* in 1703.<sup>2</sup> But the principle was not clearly defined until the House of Lords decision in *Three Rivers District Council v Bank of England* in 2000.<sup>3</sup> The tort came to Canada in 1959 in *Roncarelli v Duplessis*<sup>4</sup> but was rarely used until the Supreme Court of Canada decision in *Odhavij Estate v. Woodhouse* in 2003.<sup>5</sup>

Two recent decisions in 2008, one by the Federal Court<sup>6</sup> and the other by the Ontario

Court of Appeal,<sup>7</sup> suggest the tort may be successful where a tort of negligence would fail. In addition, malice and reckless indifference are difficult concepts making it hard to strike out these claims at the pleading stage.

In *O Dwyer*, the Ontario Court of Appeal found liability because the Commission officials were "recklessly indifferent or wilfully blind as to the illegality of their actions and their potential to harm the plaintiff." This is a broad principle that places a real constraint on questionable government action. ■

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<sup>1</sup> *Trillium Power Wind Corp. v Ontario (Natural Resources)*, 2013 ONCA 683 at paras 54-55.

<sup>2</sup> *Ashby v White* (1703) 92 ER 126.

<sup>3</sup> *Three Rivers District Council v Bank of England* (2000) 2 WLR 1220 (HL).

<sup>4</sup> *Roncarelli v Duplessis* (1959) SCR 121.

<sup>5</sup> *Odhavij Estate v Woodhouse* (2003) SCJ No 74.

<sup>6</sup> *McMaster v The Queen* 2009 FC 937.

<sup>7</sup> *O Dwyer v Ontario Racing Commission* (2008) 293 DLR (4th) 559 (Ont CA).

# THE WASHINGTON REPORT

Robert S. Fleishman\*

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This report highlights key energy regulatory developments in the United States over the last year. Energy regulatory developments in 2013 in the United States impacted numerous sectors of the energy industry and addressed a wide swath of issues. This report covers developments at the federal level, such as at the Federal Energy Regulatory Commission (FERC), the Department of Energy (DOE), the Environmental Protection Agency (EPA), Congress, and in the federal courts, as well as at the state level, such as at public service/utility commissions and in state courts, which should be of interest to readers of the *Energy Regulation Quarterly* (ERQ).

## I. Energy, Climate Change, and Greenhouse Gases

Although a number of U.S. states are pursuing far-reaching initiatives to regulate and adapt to the effects of climate change and greenhouse gases, there has been no significant legislative action by Congress. However, in 2013, President Obama began using his executive powers to set a more assertive course for the federal government.

### A. President Obama's Climate Action Plan and Administrative Efforts

As we wrote in the "Washington Report" in

the Fall 2013 issue of the ERQ,<sup>1</sup> in June 2013 President Obama released the *President's Climate Action Plan* (*Climate Plan*), identifying 30 steps to reduce carbon emissions, prepare for and adapt to the effects of climate change and related natural disasters, and participate in international climate change efforts—without requiring action from Congress.<sup>2</sup> We identified four measures directly relevant to the energy sector: (1) carbon emission limits for power plants; (2) promotion of renewable energy development; (3) investment in new energy technologies; and (4) increased energy efficiency standards for federal buildings and appliances. In January 2014, the president also used his State of the Union address to highlight his goals to promote solar energy and reduce greenhouse gas emissions.<sup>3</sup> Although many of the *Climate Plan's* initiatives remain conceptual, since the end of 2013 there have been several concrete developments.

### B. Carbon Emissions from Power Plants

Since April 2012, the EPA has been pursuing an administrative rulemaking to set greenhouse gas emissions standards for new power plants. When the president released the *Climate Plan*, he also issued a Presidential Memorandum directing the Administrator of EPA to adopt a final rule in a "timely fashion."<sup>4</sup> The initial form of

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<sup>1</sup> Robert S. Fleishman, "The Washington Report" *Energy Regulation Quarterly* (14 November 2013), online: [www.energyregulationquarterly.ca](http://www.energyregulationquarterly.ca) <<http://www.energyregulationquarterly.ca/regular-features/the-washington-report>>.

<sup>2</sup> Executive Office of the President, *The President's Climate Action Plan* (June 2013), online: The White House Washington <<http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf>>.

<sup>3</sup> Office of the Press Secretary, Press Release, "President Barack Obama's State of the Union Address" (28 January 2014), online: The White House <<http://www.whitehouse.gov/the-press-office/2014/01/28/president-barack-obamas-state-union-address>>.

<sup>4</sup> *Power Sector Carbon Pollution Standards*, 78 Fed Reg 39533 (2013).

the proposed rule<sup>5</sup> proposed a “fuel-neutral” standard that would have required the same performance—1,000 pounds of carbon dioxide per megawatt-hour—from coal-fired plants as natural gas-fired plants. This controversial proposal received over 2.5 million public comments, and EPA withdrew the original proposed rule and issued a new proposed rule on January 8, 2014.<sup>6</sup>

The new rule would set separate standards for: (1) utility boilers and integrated gasification combined cycle units based on partial implementation of carbon capture and storage as the best system of emission reductions, set at 1,100 pounds of carbon dioxide per megawatt-hour; and (2) natural gas-fired stationary combustion turbines, set at 1,000 pounds of carbon dioxide per megawatt-hour for larger units and 1,100 pounds of carbon dioxide per megawatt-hour for smaller units. The public comment period closed on March 10, 2014, and a final rule is likely to be issued soon thereafter—after which it will almost certainly be challenged in court.

EPA has not proposed standards of performance for existing, modified or reconstructed sources. However, the Presidential Memorandum directed the agency to propose such standards by June 1, 2014, and to adopt final standards by June 1, 2015. Additionally, state implementation plans to enact these standards are to be submitted to EPA by June 30, 2016.

### C. Renewable Energy

As we noted previously, the *Climate Plan* set a goal to double renewable energy production in the U.S. by 2020, including permitting of 10 gigawatts of

additional renewable energy on federal lands by 2020. The Bureau of Land Management (BLM), a branch of the Department of Interior (DOI), identified 19 Solar Energy Zones throughout six southwestern states in which solar energy development is planned to be prioritized. In recent months, BLM’s program has seen successes (such as the nearly 400-megawatt Ivanpah solar project in California becoming operational)<sup>7</sup> and setbacks (such as the first major auction of solar rights on federal land in Colorado, which failed to draw a single bid).<sup>8</sup> As of November 2013, BLM reported over 35 pending applications for solar energy development on lands that it administers.<sup>9</sup>

### D. Conventional Generation Sources and Efficiency

Last fall, we wrote that DOE had proposed a solicitation for up to \$8 billion in loan guarantees for a range of advanced fossil fuel technology projects to avoid, reduce, or sequester greenhouse gas emissions, which was finalized in December 2013.<sup>10</sup> Projects covered by the loan guarantees are expected to include carbon capture, low-carbon power systems, and efficiency improvements, and initial submissions were expected to be received by the end of February 2014. Also in December 2013, the Department of Agriculture finalized updates to its *Energy Efficiency and Conservation Loan Program*, which will provide up to \$250 million for energy efficiency upgrades by rural utilities.<sup>11</sup>

### E. U.S. Supreme Court Review of Certain EPA Rules

The U.S. energy sector is closely monitoring legal developments relating to the Obama

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<sup>5</sup> *Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, 77 Fed Reg 22392 (2012).

<sup>6</sup> *Ibid.*, 79 Fed Reg 1430 (2014).

<sup>7</sup> See Rory Carroll & Nichola Groom, *California Solar Plant Greeted with Fanfare, Doubts About Future* (13 February 2014), online: Reuters <<http://www.reuters.com/article/2014/02/13/solar-ivanpah-idUSL2N0LI1D420140213>>.

<sup>8</sup> See Mark Jaffe, *1st Auction of Solar Rights on Public Lands in Colorado Draws No Bids* (24 October 2013), online: The Denver Post <[http://www.denverpost.com/breakingnews/ci\\_24379351/first-auction-solar-rights-public-lands-colorado-draws-no-one](http://www.denverpost.com/breakingnews/ci_24379351/first-auction-solar-rights-public-lands-colorado-draws-no-one)>.

<sup>9</sup> See Bureau of Land Mgmt. Solar Energy Program, *First-In-Line Pending and Authorized Solar ROW Applications on BLM-Administered Lands as of November 1, 2013*, online: BLM solar <[http://blmsolar.anl.gov/documents/docs/Pending\\_applications\\_list.pdf](http://blmsolar.anl.gov/documents/docs/Pending_applications_list.pdf)>.

<sup>10</sup> US Dept of Energy, *Advanced Fossil Energy Projects Solicitation*, online: Loan programs Office <<http://lpo.energy.gov/resource-library/solicitations/advanced-fossil-energy-projects-solicitation/>>.

<sup>11</sup> *Energy Efficiency and Conservation Loan Program*, 78 Fed Reg 73356 (2013).

Administration's earlier efforts to regulate greenhouse gases. On February 24, 2014, the U.S. Supreme Court heard oral argument in *Utility Air Regulatory Group v. Environmental Protection Agency*.<sup>12</sup> After a 2007 decision, *Massachusetts v. Environmental Protection Agency*,<sup>13</sup> where the Supreme Court concluded that greenhouse gases from motor vehicles came within the definition of "air pollutant" under the *Clean Air Act*, EPA began to regulate greenhouse gas emissions from motor vehicles. At issue in *Utility Air Regulatory Group* is whether EPA permissibly determined that regulation of motor vehicle emissions triggered *Clean Air Act* permitting requirements under the *Prevention of Significant Deterioration (PSD)* program for stationary sources, such as power plants, that emit greenhouse gases.

Utility industry groups, the U.S. Chamber of Commerce, and a number of states challenged a number of EPA regulations covering stationary source emitters, including what are known as the Triggering and Tailoring Rules. During argument, the Court focused on, among other things, whether EPA had the authority to adopt the *Tailoring Rule*,<sup>14</sup> under which EPA raised statutory emissions thresholds for greenhouse gases to ensure that only the largest stationary sources of greenhouse gas emissions would be covered.<sup>15</sup> Commentary on the arguments suggests a close decision divided along ideological lines, with the more liberal justices possibly concluding that EPA acted permissibly, and the more conservative justices possibly concluding the opposite.<sup>16</sup> As discussed

above, the Obama Administration's Climate Plan calls for other, complementary regulation of emissions from power plants. Although the Court will not directly consider these regulations in *Utility Air Regulatory Group*, its decision—not expected until June 2014—may affect the scope and nature of these new regulatory efforts.

## II. DOE and LNG Exports

As reported last fall, DOE in 2013 ended a year-long hiatus in issuing authorizations to export volumes of liquefied natural gas (LNG) to countries with which the United States does not have a free trade agreement (non-FTA countries).

In the last authorization issued in 2013,<sup>17</sup> DOE authorized Freeport to export only an additional 0.4 Bcf/day to non-FTA countries although Freeport had requested authorization to export an additional 1.4 Bcf/day to such countries. DOE's approval of less than the total amount requested to be authorized for export to non-FTA countries led some to speculate that DOE may intend to cap the volumes that it will authorize for export to non-FTA countries. DOE based its determination on Freeport's separate application to FERC for authorization to construct the liquefaction facilities, which described the capacity of the liquefaction project as 1.8 Bcf/day.

DOE's LNG export authorizations have reserved the agency's authority to revoke (in whole or in part) a previously issued authorization, stating

<sup>12</sup> *Utility Air Regulatory group v Environmental Protection Agency*, 684 F (3d) 102 (DC Cir 2012), No 12-1146 (US cert granted 15 October 2013). *Utility Air Regulatory Group* is the lead case for 6 consolidated cases pertaining to the same issue.

<sup>13</sup> *Massachusetts v Environmental protection Agency*, 549 US 497 (2007).

<sup>14</sup> *Prevention of Significant Deterioration and Title v Greenhouse Gas Tailoring Rule*, 75 Fed Reg 31514 (2010).

<sup>15</sup> See Adam Liptak, *For the Supreme Court, a Case Poses a Puzzle on the E.P.A.'s Authority* (24 February 2014), online: the New York Times <[http://www.nytimes.com/2014/02/25/us/justices-weigh-conundrum-on-epa-authority.html?\\_r=0](http://www.nytimes.com/2014/02/25/us/justices-weigh-conundrum-on-epa-authority.html?_r=0)>.

<sup>16</sup> E.g., Sean McLernon, *Split High Court Presses Industry, EPA Over Carbon Rules* (24 February 2014), online: Law360 <<http://www.law360.com/energy/articles/500427/split-high-court-presses-industry-epa-over-carbon-rules>>; Mark Sherman, *Supreme Court Seems Divided in Climate Case*, online: Associated Press <[http://www.washingtonpost.com/politics/courts\\_law/climate-case-at-supreme-court-looks-at-epas-power/2014/02/24/95f5f6b8-9d2e-11e3-8112-52fdf646027b\\_story.html](http://www.washingtonpost.com/politics/courts_law/climate-case-at-supreme-court-looks-at-epas-power/2014/02/24/95f5f6b8-9d2e-11e3-8112-52fdf646027b_story.html)>.

<sup>17</sup> US Dep't of Energy, DOE/FE Order No 3357, *Order Conditionally Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel from the Freeport LNG Terminal on Quintana Island, Texas to Non-Free Trade Agreement Nations* (15 November 2013), online: Office of Fossil Energy <[http://www.fossil.energy.gov/programs/gasregulation/authorizations/Orders\\_Issued\\_2013/ord3357.pdf](http://www.fossil.energy.gov/programs/gasregulation/authorizations/Orders_Issued_2013/ord3357.pdf)>.

that “[w]e cannot precisely identify all the circumstances under which such action would be taken.” Specifically, each authorization states that “[i]n the event of any unforeseen developments of such significance as to put the public interest at risk, DOE/FE is authorized by section 3(a) of the *Natural Gas Act [NGA]*... to make a supplemental order as necessary or appropriate to protect the public interest.” The authorizations continue, “[a]dditionally, the DOE is authorized by section 16 of the *[NGA]* ‘to perform any and all acts and to prescribe, issue, make, amend and rescind such orders, rules and regulations as it may find necessary or appropriate’ to carry out its responsibilities.”

In response to concerns raised by LNG export proponents, leaders of the Senate Committee on Energy and Natural Resources sent a letter on August, 2, 2013 to the Secretary of Energy requesting clarification of the circumstances under which DOE might revoke or modify an export authorization.<sup>18</sup> In the letter they cite to the *NGA*, which empowers DOE to “amend, and rescind such orders . . . as it may find necessary or appropriate to carry out the provisions of the *NGA*,”<sup>19</sup> and to the *Energy Policy and Conservation Act of 1975*, which provides DOE authority to revoke or substantially modify previously authorized export licenses as the president determines appropriate and necessary.<sup>20</sup>

DOE’s Deputy Assistant Secretary issued a letter in response to the inquiry on October 17, 2013, stating: (1) DOE “would not rescind a previously granted authorization except in the event of extraordinary circumstances,” and that it “takes very seriously the investment-backed expectations of private parties” and would not exercise its revocation authority “as a price maintenance mechanism”; (2) DOE has never vacated or rescinded an authorization to

import or export natural gas over the objections of the authorization holder, noting that such authorizations have only been rescinded when the authorization holder requested the authorization be vacated, had gone out of business, or was non-responsive to DOE’s inquiries; (3) DOE would not consider the cumulative impact of other authorizations when deciding whether to rescind an authorization; and (4) neither the *NGA* nor DOE regulations limit the submission of a request to suspend or revoke a final order to the parties in the prior authorization proceeding, and accordingly DOE would permit all interested parties to participate before a decision on a proposed revocation of an export authorization.<sup>21</sup>

### III. Hydraulic Fracturing

Standards and policies surrounding hydraulic fracturing (hydrofracking) for natural gas and oil continue to be developed through both regulation and state and local litigation, and are increasingly controversial.

#### A. Federal Regulations

EPA has not issued federal hydrofracking regulations but is conducting a study commissioned by Congress to understand the potential impacts of hydrofracking on drinking water resources. EPA held a technical workshop in 2013 that covered data collection and modeling, well construction, wastewater treatment and water acquisition modeling. It issued a progress report in December 2012<sup>22</sup> and a draft report with preliminary findings is expected to be released for public comment and peer review in late 2014.

In May 2013, the DOI released an updated draft proposal that would establish hydrofracking safety standards on public lands

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<sup>18</sup> Letter from Sen. Ron Wyden and Sen. Lisa Murkowski to Ernest Moniz, U.S. Sec’y of Energy (2 August 2013), online: United States Senate <[http://www.energy.senate.gov/public/index.cfm/files/serve?File\\_id=fcd19e75-9ff9-4d75-aa4e-7330b5f8b03f](http://www.energy.senate.gov/public/index.cfm/files/serve?File_id=fcd19e75-9ff9-4d75-aa4e-7330b5f8b03f)>.

<sup>19</sup> *Natural Gas Act*, 15 USC §§ 3(a), 16, 717b, 717o (2013).

<sup>20</sup> *Energy Policy and Conservation Act of 1975 (EPCA)*, 42 USC § 6201 *et seq* (2013).

<sup>21</sup> Letter from Paula A. Gant, Deputy Assistant Sec’y, Dep’t of Energy, to Sen. Lisa Murkowski (17 October 2013), online: United States Senate <[http://www.energy.senate.gov/public/index.cfm/files/serve?File\\_id=9e99e412-ce05-449d-8893-dc8d64c32d02](http://www.energy.senate.gov/public/index.cfm/files/serve?File_id=9e99e412-ce05-449d-8893-dc8d64c32d02)>.

<sup>22</sup> United States Environmental Protection Agency, *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources: progress report* (December 2012), online: EPA <<http://www2.epa.gov/hfstudy/study-potential>>.

under DOI's control.<sup>23</sup> The proposal updated DOI's initial draft proposal issued in 2012, which garnered over 177,000 public comments during the initial comment period. If adopted, the proposal would be the first federal regulations governing hydrofracking in the United States. In November 2013, the House of Representatives passed H.R. 2728 that, if signed into law, would prevent DOI from regulating hydrofracking in states that already have passed their own regulations.<sup>24</sup>

### B. State and Local Regulations

In November 2013, a number of cities in Colorado, including Fort Collins and Lafayette, approved ballot initiatives banning hydrofracking within city limits. The Fort Collins initiative prohibits hydrofracking and the storage or disposal of related waste products for five years, while the Lafayette initiative permanently bans hydrofracking. Soon after the initiatives were passed, the Colorado Oil and Gas Association sued both cities claiming that the initiatives violate the requirement of uniform regulation in the state's *Oil and Gas Conservation Act*.<sup>25</sup>

California and Illinois issued proposed rules for hydrofracking that represent the first state-wide regulations that would permit hydrofracking subject to regulation. By contrast, several states, including New York and Maryland, have effective statewide moratoria on hydrofracking. California's proposed rules would establish standards relating to notification, groundwater monitoring, and disclosure of the types and concentrations of hydrofracking-related chemicals, and also would call for a statewide review of hydrofracking.<sup>26</sup> The proposed Illinois

regulations,<sup>27</sup> which implement the *Hydraulic Fracturing Regulation Act*, would address water usage and pollution, such as generally requiring well wastewater to be maintained in tanks instead of open pits.

### C. State Litigation<sup>28</sup>

In December 2013, in *Robinson Township v Commonwealth of Pennsylvania*,<sup>29</sup> the Pennsylvania Supreme Court voted 4-2 to strike down portions of the *Marcellus Shale drilling law, Act 13*,<sup>30</sup> holding that several of its provisions violated the Commonwealth's constitution. *Act 13* prohibited local regulation of oil and gas operations, reserved regulatory authority over those activities to the Commonwealth, and restricted local municipalities' ability to dictate where companies could locate waste pits, pipelines, rigs, and compressor and processing stations. Several parties, including municipalities and environmental organizations, brought suit seeking a declaration of unconstitutionality and a permanent injunction prohibiting application of *Act 13*. An intermediary state court had handed down a partial victory for the Plaintiffs by striking down portions of *Act 13* on due process grounds, thus "prohibit[ing] the Department of Environmental Protection from granting waivers of mandatory setbacks from certain types of state waters and permitting local governments to enforce existing zoning ordinances, adopt new ordinances... without concern for the legal or financial consequences."<sup>31</sup>

In its decision, the Pennsylvania Supreme Court invalidated a number of *Act 13*'s core provisions, including the requirement for

impacts-hydraulic-fracturing-drinking-water-resources-progress-report-0>.

<sup>23</sup> *Oil and Gas; Hydraulic Fracturing on Federal and Indian Lands*, 78 Fed Reg 31635 (2013).

<sup>24</sup> US, Bill HR 2728, *Protecting States' Rights to Promote American Energy Security Act*, 113th Cong, (2013-2014).

<sup>25</sup> Colo Rev Stat § 34-60-101 *et seq* (2013).

<sup>26</sup> Cal Code Reg tit 14, § 1761 (2014), online: <<http://www.conservation.ca.gov/dog/Documents/Final%20Interim%20Regulations.pdf>>.

<sup>27</sup> Ill Admin Code tit. 62 § 245 (2013).

<sup>28</sup> For details regarding *Norse Energy Corp. v Town of Dryden*, 964 NYS.2d 714 (NY App Div 2013), currently pending before the Court of Appeals for New York, see the Fall 2013 issue of *ERQ*.

<sup>29</sup> *Robinson Township v Commonwealth of Pennsylvania*, No 63 MAP 2012, 2013 WL 6687290 (Pa 2013)[*Robinson Township*].

<sup>30</sup> 58 Pa Cons Stat §§ 2301-3504.

<sup>31</sup> *Robinson Township*, *supra* note 29 at 16.

uniform statewide zoning standards for oil and gas operations. Unlike the lower court, the Pennsylvania Supreme Court did not rest its decision on due process grounds and instead held that *Act 13* violated the *Environmental Rights Amendment* of the Commonwealth's constitution, which guarantees citizens' rights "to clean air and pure water, and to the preservation of natural, scientific, historic and esthetic values of the environment."<sup>32</sup> Writing for the majority, Chief Justice Ronald D. Castille declared that *Act 13* "effectively disposed of the regulatory structures upon which citizens and communities made significant financial and quality of life decisions, and has sanctioned a direct and harmful degradation of the environmental quality of life in these communities and zoning districts."<sup>33</sup>

#### IV. PPL Litigation and Electric Capacity Markets

FERC has worked with regional transmission organizations (RTOs), independent system operators (ISOs) and other stakeholders to develop capacity markets in various regions of the United States. Among other things, such markets are designed to incent market participants to build new electric generating plants and thus increase capacity. Two federal district court decisions, one in Maryland and one in New Jersey, struck down state programs that encouraged the construction of new gas-fired capacity in the PJM region where generating capacity was deemed insufficient by state authorities.<sup>34</sup> The programs in both states conducted competitive solicitations and used contract-for-differences pricing schemes for capacity that offered winning bidders a fixed bid price from the local utilities. In a nutshell, bidders were required to bid into, and sell capacity in, the PJM market, and any revenue from that sale would offset the fixed bid price. The programs were challenged under the

*U.S. Constitution on Supremacy Clause and Commerce Clause* grounds. First, plaintiffs claimed that FERC has been given exclusive jurisdiction over wholesale ratemaking under the *Federal Power Act (FPA)*, and the pricing schemes set by the states violated the *Supremacy Clause*. Second, plaintiffs claimed that the state bidding requirements unfairly discriminated against out-of-state power producers in violation of the *Commerce Clause*. Both the Maryland and New Jersey courts held that the pricing conflicted with FERC's exclusive authority under the *FPA* and thus violated the *Supremacy Clause*, but that the *Commerce Clause* was not violated.<sup>35</sup>

The decisions are significant as they illuminate the tensions between state and federal programs to encourage the construction of new generation facilities and raise questions about the legality of mandates and renewable portfolio standard programs in other states.

#### V. FERC Enforcement and Alleged Market Manipulation

FERC's Office of Enforcement (Enforcement) had a landmark year in 2013. As highlighted in its annual report,<sup>36</sup> FERC continued to focus its enforcement efforts in four principal areas: (1) fraud and market manipulation; (2) serious violations of the reliability standards; (3) anticompetitive conduct, and (4) conduct threatening the transparency of regulated markets. Enforcement opened 24 new investigations of market participants (up from 16 in 2012) and resolved 29 more with no action, a settlement, or formal enforcement action.

The year's most significant enforcement matters came as a result of FERC's authority to prosecute under the *FPA* and *NGA* and impose civil penalties of up to \$1 million per

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<sup>32</sup> *Ibid* at 33.

<sup>33</sup> *Ibid* at 58.

<sup>34</sup> The New Jersey decision is *PPL EnergyPlus, LLC v Hanna*, No 11-745, 2013 WL 5603896 (DNJ) (11 October 2013) [*Hanna*]. The Maryland decision is *PPL EnergyPlus, LLC, Nazarian*, No MJG-12-1286, 2013 WL 5432346 (D Md) (30 September 2013) [*Nazarian*]. Appeals are pending in the US Courts of Appeals for the Third and Fourth Circuits, respectively.

<sup>35</sup> *Hanna*, *ibid* at 36; *Nazarian*, *ibid* at 31.

<sup>36</sup> Federal Energy Regulatory Commission, *2013 Report on Enforcement*, FERC Docket No AD07-13-006 (21

day for market manipulation and fraud.<sup>37</sup> These matters are briefly described below. A more detailed discussion of these matters (except *Lincoln Paper and Tissue LLC et al.*) can be found in the Fall 2013 issue of the *ERQ*.

#### A. Barclays Bank PLC et al.

On July 16, 2013, FERC assessed civil penalties<sup>38</sup> totaling \$435 million and ordered \$34.9 million in disgorgement against Barclays Bank PLC (Barclays) and further assessed civil penalties totaling \$18 million against certain Barclays' traders for allegedly manipulating energy markets in and around California between 2006 and 2008. The penalty ordered against Barclays marks the largest of its kind in the agency's history. Barclays and the individual traders have denied FERC's allegations and elected to challenge the penalties in federal court.

On October 9, 2013, FERC petitioned the U.S. District Court for the Eastern District of California to issue an order affirming its assessment of penalties against Barclays and the individual traders. On December 16, 2013, Barclays and the individual traders responded by filing a motion to dismiss<sup>39</sup> FERC's petition. The motion raises a number of important legal questions relating to FERC's authority to police electricity markets. The motion, for example, argues that FERC lacks jurisdiction over the relevant transactions because they were commodity futures transactions over which the Commodity Futures Trading Commission (CFTC) has exclusive jurisdiction under the *Commodity Exchange Act (CEA)*, and because they did not result in physical delivery or transmission of electricity, as the movants claim is required for FERC jurisdiction under the *FPA*. The motion also argues that the relevant

transactions were neither manipulative nor fraudulent because they were executed between willing parties in an open and transparent market, and that the individual traders cannot be held liable for manipulation because the *FPA* prohibits only an "entity" (not natural persons) from engaging in manipulation. FERC's response takes issue with these positions. The court has not yet ruled on the motion.<sup>40</sup> An adverse ruling for FERC on any one of these issues could significantly limit FERC's enforcement authority.

#### B. JP Morgan Ventures Energy Corporation

On July 31, 2013, FERC approved a settlement<sup>41</sup> with JP Morgan Ventures Energy Corporation (JPMVEC) providing for civil penalties of \$285 million and disgorgement of \$125 million. The settlement resolved allegations that JPMVEC manipulated certain energy markets in California and the Midwest between 2010 and 2012. Pending the outcome in *Barclays*, FERC's settlement with JPMVEC stands as the largest civil penalty assessed by FERC and paid by the subject of an enforcement investigation.

#### C. B.P. America et al.

On August 5, 2013, FERC ordered<sup>42</sup> BP America Inc., BP Corporation North America Inc., BP America Production Company, and BP Energy Company (collectively, BP) to show cause why it should not be found to have illegally manipulated a certain natural gas market in Houston from September to November 2008, be assessed penalties totaling \$28 million, and be forced to disgorge \$800,000 in unjust profits. On October 4, 2013, BP filed an answer denying all wrongdoing and requesting

November 2013), online: FERC <<https://www.ferc.gov/legal/staff-reports/2013/11-21-13-enforcement.pdf>>.

<sup>37</sup> See 16 USC § 824v(a) (2012); 15 USC § 717c-1 (2012).

<sup>38</sup> *Barclays Bank PLC*, 144 FERC ¶ 61041 (2013).

<sup>39</sup> Notice of Motion and Motion to Dismiss, *FERC v Barclays Bank PLC*, No 2:13-cv-02093-TLN-DAD (ED Cal) (16 December 2013).

<sup>40</sup> FERC filed a brief opposing Barclays' and the individual traders' motion to dismiss on February 14, 2014. See Petitioner's Opposition to Respondents' Motion, *FERC v Barclays Bank PLC*, No 2:13-cv-02093-TLN-DAD (ED Cal) (14 February 2013).

<sup>41</sup> *In re Make-Whole Payments & Related Bidding Strategies*, 144 FERC ¶ 61,068 (2013).

<sup>42</sup> *BP America Inc.*, 144 FERC ¶ 61,100 (2013).

that FERC dismiss the proceeding or, in the alternative, set the matter for a full evidentiary hearing before an administrative law judge at the agency. BP's request is pending before the Commission.

#### D. Lincoln Paper and Tissue LLC *et al.*

On August 29, 2013, FERC issued orders<sup>43</sup> assessing civil penalties of \$5 million, \$7.5 million, and \$1.25 million against Lincoln Paper and Tissue LLC (Lincoln), Competitive Energy Services, LLC (CES), and Richard Silkman (Silkman), CES' managing partner, respectively, alleging that they manipulated ISO New England's demand response markets.<sup>44</sup> The orders also sought disgorgement of unjust profits of approximately \$380,000 from Lincoln and \$170,000 from CES. Each order principally found that the subjects devised and carried out schemes to collect payments for demand response without actually reducing electricity consumption from the grid. According to FERC, the subjects collected such payments by fraudulently inflating load baselines<sup>45</sup> and repeatedly offering load reductions at the minimum offer price to maintain inflated baselines. FERC concluded Lincoln, CES, and Silkman made uneconomic energy purchases that served no legitimate business purpose and were designed to increase demand response payments that would not have been received absent of the uneconomic transactions. FERC also accused Rumford Paper Company

(Rumford) of similar conduct, but Rumford settled<sup>46</sup> with the agency.

On December 2, 2013, FERC filed petitions<sup>47</sup> in the U.S. District Court for the District of Massachusetts seeking orders affirming its imposition of penalties against Lincoln, CES, and Silkman. FERC sought this relief in Federal District Court after the subjects did not pay the penalties within the allotted 60 days. The court may affirm, modify, or vacate FERC's order, either in whole or in part.<sup>48</sup> FERC's enforcement action against Lincoln, CES, and Silkman, as well as its settlement with Rumford, illustrate the agency's increased focus on market participants' conduct in demand response programs in recent years.<sup>49</sup>

#### VI. CFTC and Dodd-Frank Developments

The CFTC's implementation of sweeping derivatives reforms under the *Dodd-Frank Wall Street Reform and Consumer Protection Act* (*Dodd-Frank*) continued forward in 2013. Gary Gensler—the subject of both praise and consternation for his role as architect of many such reforms—stepped down as CFTC Chairman at the beginning of January 2014, but not before establishing, or sowing the seeds for, most of *Dodd-Frank's* remaining major derivatives reforms. Key *Dodd-Frank* developments in 2013 affecting energy companies are described below.

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<sup>43</sup> *Lincoln Paper & Tissue, LLC*, 144 FERC ¶ 61,162 (2013); *Competitive Energy Servs., LLC*, 144 FERC ¶ 61,163 (2013); *Richard Silkman*, 144 FERC ¶ 61,164 (2013).

<sup>44</sup> "Demand response" refers to a reduction in customers' consumption of electricity from their anticipated consumption in response to an increase in the price of electricity or to incentive payments designed to induce lower electricity consumption.

<sup>45</sup> "Baseline" is an estimate of a customer's anticipated level of electricity consumption. The baseline is used to measure the quantity of demand response (*i.e.*, reduction of electrical consumption) delivered to the grid.

<sup>46</sup> See *Rumford Paper Co.*, 142 FERC ¶ 61,218 (2013).

<sup>47</sup> Petition for an Order Affirming the Federal Energy Regulatory Commission's August 29, 2013 Order Assessing Civil Penalty Against Lincoln Paper and Tissue, LLC, *FERC v Lincoln Paper & Tissue, LLC*, No 1:13-cv-13056-DPW (D Mass) (2 December 2013); Petition for an Order Affirming the Federal Energy Regulatory Commission's August 29, 2013 Order Assessing Civil Penalty Against Richard Silkman and Competitive Energy Services, LLC, *FERC v Silkman*, No 1:13-cv-13054-DPW (D Mass) (2 December 2013).

<sup>48</sup> Lincoln filed a motion to dismiss FERC's petition on February 14, 2014. See *Lincoln Paper and Tissue, LLC's Motion to Dismiss Complaint, FERC v Lincoln Paper & Tissue, LLC*, Docket No 1:13-cv-13056-DPW (2 December 2013). The motion argues, among other things, that FERC's petition is time-barred by the applicable statute of limitations and that FERC lacks jurisdiction over demand response. CES and Silkman also filed motions to dismiss.

<sup>49</sup> See *Enerwise Global Techs. Inc.*, 143 FERC ¶ 61,218 (2013) (settling allegations of market manipulation against demand response provider and imposing monetary penalties and remedies totaling approximately \$1.3 million).

### A. Position Limits

The CFTC continued its initiative to establish federal speculative position limits, a key issue for many energy companies, by re-proposing in November 2013 position limits rules<sup>50</sup> that in September 2012 had been vacated on procedural grounds by a federal court. The new proposal augments the previously provided rationales for the imposition of federal limits and is substantially similar to the vacated rules in prescribing spot-month and non-spot-month limits for 28 physical commodity agricultural, metal and energy futures contracts and their “economically equivalent” futures, options and swaps. Like the vacated rules, the proposal would also exempt from the limits certain enumerated hedging positions upon submission of specified filings to the CFTC. The CFTC also re-proposed aggregation rules<sup>51</sup> which largely mirror (and in some cases provide greater flexibility than) earlier rules proposed in May 2012. Some have criticized sharply the new proposed position limits and aggregation rules for not doing enough to minimize the obligations of commercial market participants, in particular, commercial hedgers. It remains to be seen whether the CFTC will be receptive to such criticism if and when it adopts final position limits and aggregation rules.

### B. Cross-Border Guidance

In July 2013, the CFTC issued the much anticipated—and perhaps equally controversial—guidance<sup>52</sup> on the cross-border application of *Dodd-Frank*’s swap provisions. Among other U.S. end users, the guidance impacts energy companies with overseas affiliates. The guidance is the culmination of a series of CFTC publications dating back to July 2012 on cross-border issues and, in general, describes the *Dodd-Frank* requirements that apply to swaps with one or more non-U.S.

counterparties. Notable issues addressed in the guidance include the definition of “U.S. person,” the application of the swap dealer and major swap participant thresholds and analysis and applicability of entity-level and transaction-level requirements to swaps with U.S. and non-U.S. persons, obligations of non-U.S. non-registrant end users and the availability of substituted compliance. In December 2013, the CFTC issued comparability determinations making substituted compliance available for six jurisdictions, but these determinations were limited and did not cover key requirements such as mandatory clearing, mandatory trade execution or regulatory swap reporting. Industry groups are seeking to invalidate the guidance on procedural grounds in federal court.<sup>53</sup>

### C. CFTC-FERC Memoranda of Understanding

On January 2, 2014, the CFTC and FERC (collectively, the agencies) signed “Memoranda of Understanding”<sup>54</sup> regarding certain matters of overlapping jurisdiction (jurisdiction MOU) and sharing information in connection with market surveillance and enforcement activities (information sharing MOU, collectively, the MOUs). The MOUs came nearly three years after a statutory deadline, imposed by Section 720 of *Dodd-Frank*, for the agencies to negotiate such memoranda. The agencies had been operating under a 2005 Memorandum of Understanding generally providing for cooperation in enforcement matters but not explicitly recognizing the prospect of overlapping jurisdiction.

The agencies have sparred on jurisdiction over energy markets in recent years as their enforcement activities expanded. In a federal appeals court, for example, the CFTC sided with the subject of a FERC enforcement

<sup>50</sup> Position Limits for Derivatives, 78 Fed Reg 75680 (12 December 2013).

<sup>51</sup> Aggregation of Positions, 78 Fed Reg 68946 (15 November 2013).

<sup>52</sup> *Interpretive Guidance and Policy Statement Regarding Compliance with Certain Swap Regulations*, 78 Fed Reg 45292 (26 July 2013).

<sup>53</sup> Complaint, *Securities Indus. & Fin. Mkts. Ass’n v CFTC*, No. 13-cv-1916 (DDC) (4 December 2013), ECF No 1.

<sup>54</sup> *Memorandum of Understanding between the Federal Energy Regulatory Commission and the Commodity Futures Trading Commission* (2 January 2014), online: FERC <<https://www.ferc.gov/legal/mou/mou-ferc-cftc-jurisdictional.pdf>>; *Memorandum of Understanding between the Commodity Futures Trading Commission and the Federal Energy Regulatory*

investigation in challenging FERC's authority to impose a \$30 million civil penalty for alleged manipulation of the natural gas futures market. The court held in March 2013 against FERC, reasoning that the CFTC has exclusive authority to police futures markets under the CEA.<sup>55</sup> Some thought the court's decision would encourage the agencies to issue the jurisdiction MOU soon after the ruling, but the agencies did not reach agreement on an MOU until the end of 2013, and ultimately avoided committing to any substantive positions in the jurisdiction MOU.

## VII. California Public Utilities Commission Energy Storage Mandate

In October 2013, the California Public Utilities Commission (CPUC) unanimously passed the United States' first energy storage mandate. The mandate requires the state's largest three investor-owned utilities—Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company—to add 1.325 gigawatts of energy storage to their grids by 2020. Three policy goals guided the target: (1) grid optimization, including reliability, peak reduction, and deferred transmission and distribution system upgrades; (2) integration of renewable energy; and (3) California's goal of reducing greenhouse gas emissions to 80 per cent below 1990 levels by 2050.<sup>56</sup>

The mandate also prohibits utilities from owning more than 50 per cent of the storage projects they propose, with the goal of promoting merchant storage, customer-owned energy assets, and other arrangements that may be difficult to incorporate into current regulatory frameworks.<sup>57</sup> To meet the 1.325 gigawatt target, the utilities must plan for energy loss during the energy storage process

and the extra capacity required to cover those losses.

Under the mandate, the CPUC must judge the cost effectiveness of the energy storage plan, and the burden of proof rests on the owners.<sup>58</sup> The CPUC will rely initially on energy storage evaluation software tools developed by the Electric Power Research Institute and utility consultancy DNV KEMA to make this determination. The CPUC also will need to match emerging storage technologies, such as grid batteries, thermal energy systems, and microgrid projects, with correct market and regulatory mechanisms to measure their cost-effectiveness.

## VIII. Smart Grid and Privacy

In recent years, intelligence has been increasingly added to the U.S. grid through the deployment of advanced technologies and grid modernization efforts. In turn, this increased intelligence has led to concerns regarding consumer privacy and security. In January 2012, DOE's Office of Electricity and Energy Reliability convened a workshop to facilitate a dialogue among key industry stakeholders regarding privacy and the fast-developing smart grid. Thereafter, in February 2012, the White House issued *Consumer Data Privacy in a Networked World: A Framework for Protecting Privacy and Promoting Innovation in the Global Digital Economy* (White House Report).<sup>59</sup> The White House Report outlined a multi-stakeholder process for developing legally enforceable voluntary codes of conduct to help instill consumer confidence that information is being protected, as well as a *Consumer Privacy Bill of Rights*.

DOE and the Federal Smart Grid Task Force then formed a group to facilitate a multi-stakeholder

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*Commission Regarding Information Sharing and Treatment of Proprietary Trading and Other Information* (2 January 2014), online: FERC <<https://www.ferc.gov/legal/mou/mou-ferc-cftc-info-sharing.pdf>>.

<sup>55</sup> See *Hunter v FERC*, 711 F (3d) 155 (DC Cir 2013).

<sup>56</sup> CPUC, *Proposed Decision of Commissioner Peterman, Decision Adopting Energy Storage Procurement Framework and Design Program*, App A (17 October 2013), online: CPUC <<http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M078/K912/78912194.PDF>>.

<sup>57</sup> *Ibid* at 33.

<sup>58</sup> *Ibid* App A at 3, 7.

<sup>59</sup> White House, *Consumer Data Privacy in a Networked World: A Framework for Protecting Privacy and Promoting Innovation in the Global Digital Economy* (23 February 2012), online: The White House <<http://www.whitehouse.gov/>

process to develop a voluntary code of conduct for utilities and third parties providing consumer energy use services that addresses privacy related to data enabled by smart grid technologies. Thereafter, at its November 22, 2013 meeting, the Smart Grid Task Force proposed a mission statement intended to: (1) encourage innovation while appropriately protecting the privacy of consumer data and providing reliable, affordable electric and energy-related service; (2) provide customers with appropriate access to their own customer data; and (3) not infringe on or supersede any law, regulation, or governance by any applicable federal, state, or local regulatory authority.

The voluntary code of conduct addresses the following subject areas: (1) notice and awareness, (2) company management and customer redress, (3) choice and consent, (4) integrity and security, and (5) data access and participation. It was intended to be applicable to, and voluntarily adopted by, both utilities and third parties. According to the mission statement, the intent is for utilities and third parties to consider adopting the voluntary code of conduct in its entirety, although exceptions may occur when state or local regulations indicate a different approach. The mission statement notes that the voluntary code of conduct could be most beneficial to either entities that are not subject to regulation by applicable regulatory authorities or entities whose applicable regulatory authorities have not imposed relevant requirements. A proposed final report is expected to be available in 2014.

#### **IX. Demand Response and Enhanced Measurement and Verification**

The *Energy Policy Act* of 2005<sup>60</sup> requires FERC to prepare a report that assesses electric demand response resources and the penetration rate of advanced meters. The *Energy Independence and Security Act of 2007*<sup>61</sup> builds on this requirement in directing FERC and DOE to perform a national assessment of demand response potential and develop a national

action plan on demand response.

FERC has taken a number of actions to ensure that demand resources receive comparable treatment in jurisdictional transmission planning processes. Among them is Order No. 890, which, among other things, requires that public utility transmission providers consider all types of resources, including demand response and energy efficiency, on a comparable basis in transmission planning. Through its processing of compliance filings in response to its Order No. 1,000, FERC reaffirmed this Order No. 890 requirement.

FERC has also taken steps recently to ensure that demand response is competing on a level playing field with other resources. In February 2013, FERC issued Order No. 676-G amending its regulations to incorporate by reference updated business practice standards adopted by the Wholesale Electric Quadrant of the North American Energy Standards Board to categorize various products and services for demand response and energy efficiency products offered in organized wholesale markets. The standards require each RTO and ISO to address in its governing documents the performance evaluation methods to be used for demand response and energy efficiency products.<sup>62</sup>

A FERC staff report released in October 2013 summarized the new standards for energy efficiency adopted in Order No. 676-G. The report stated that they provide criteria that will support the measurement and verification of energy efficiency products and services in organized wholesale electric markets as well as acceptable measurement and verification methodologies that energy efficiency resource providers may use. The report further said they provide criteria for determining which type of baseline to use in various situations, such as the installation of new energy efficient equipment and processes or the replacement of outdated equipment.

sites/default/files/privacy-final.pdf>.

<sup>60</sup> *Energy Policy Act of 2005*, Pub L No 109-58, § 1252(e)(3), 119 Stat 594 at 966 (2005).

<sup>61</sup> *Energy Independence and Security Act of 2007*, Pub L No 110-140, § 529, 121 Stat 1492, 1664 (2007) (to be codified at *National Conservation Policy Act*, 42 USC §§ 8241-8279).

<sup>62</sup> *Standards for Business Practices and Communication Protocols for Public Utilities*, 142 FERC ¶ 61,131 at P 1 (2013).

The standards also contain, according to the report, rules regarding the statistical methods used to accurately determine reduction values, specification for equipment used to perform measurements, and data validation.<sup>63</sup> Finally, the report concluded that the standards will facilitate the ability of demand response and energy efficiency providers to participate in organized wholesale electric markets, reducing transaction cost and providing an opportunity for more customers to participate in such programs.<sup>64</sup>

## **X. Energy Tax Credits**

The production tax credit (PTC) for wind and other renewable energy technologies expired at the end of 2013. However, pursuant to the *American Taxpayer Relief Act of 2012* (enacted in January 2013), eligible projects that were “under construction” before January 1, 2014 were allowed to qualify for the PTC or for the energy investment tax credit in lieu of the PTC. The Internal Revenue Service issued Notice 2013-29 in April 2013 and Notice 2013-60 in September 2013 addressing what it means for a project to qualify as “under construction,” and clarifying, among other things, that a change in ownership did not affect the project’s qualification for the tax credits.

On December 18, 2013, the Senate Finance Committee Chair, Max Baucus, D-Mont., released a discussion draft of legislation that would fundamentally change U.S. energy tax incentives.<sup>65</sup> The U.S. tax laws contain over 40 energy related tax incentives, but well over half of these have short-term expiry dates, creating considerable uncertainty for investors and developers seeking to utilize these incentives.

Senator Baucus’ proposal would adopt two new nonrefundable tax credits for clean energy and clean transportation fuels. Those credits, rather than requiring regular renewal, would

be tied to national reductions in greenhouse gas intensity in U.S. electricity facilities and transportation fuels. The credits would be available to facilities using all technologies as long as emissions standards are satisfied.

The credit would be available as either: (1) a production tax credit of up to 2.3 cents per kilowatt-hour for energy or up to \$1 per gallon for transportation fuel produced over a ten-year period; or (2) an investment tax credit (ITC) of up to 20 per cent of the cost of the facility producing energy or transportation fuels. Notably, the new ITC would reduce the percentage of the cost of a facility that is eligible for the credit from 30 to 20 per cent. Businesses could choose between claiming the credit as a PTC or ITC. The new PTC and ITC would be available for at least a ten-year period, but would not be permanent. Any facility producing electricity that is approximately 25 per cent cleaner than the average for all electricity production facilities would be eligible to receive the new PTC or ITC. The principle that the proposal seeks to implement is: the “cleaner” the facility, the larger the credit. The new PTC and ITC for energy facilities would not be available to facilities that are placed in service before January 1, 2017. However, after 2016, the ITC could be claimed for existing facilities that undertake a carbon capture and sequestration retrofit that captures at least 50 per cent of carbon dioxide emissions. The clean energy credits would phase out over a period of four years after the greenhouse gas intensity of U.S. electricity generation has declined to the point that it is 25 per cent cleaner than 2013 emissions.

Although Senator Baucus no longer chairs the Senate Finance Committee, it is expected that his successor, Senator Ron Wyden, D-Wash., will give the draft legislation careful consideration.

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<sup>63</sup> FERC Staff Report, *Assessment of Demand Response & Advanced Metering* (October 2013), online: FERC <<https://www.ferc.gov/legal/staff-reports/2013/oct-demand-response.pdf>>.

<sup>64</sup> *Ibid* at 2.

<sup>65</sup> Max Baucus, Senate Committee on Finance, *Energy Tax Reform Discussion Draft* (18 December 2013), online: <<http://www.finance.senate.gov/imo/media/doc/121813%20Energy%20Tax%20Reform%20Discussion%20Draft%20Language1.pdf>>.

## XI. Gas-Electric Coordination

In 2013, FERC continued to be active in its efforts to identify opportunities to improve coordination between the natural gas and electricity industries.<sup>66</sup> FERC focused primarily on the ability of such industries to communicate and share information, which it views as essential for the efficient operation of both industries.<sup>67</sup> In July 2013, FERC issued a proposed rulemaking seeking comments on rule changes designed to foster “robust communication” between the industries “to ensure that both systems operate safely and effectively for the benefits of their customers.”<sup>68</sup> In November, it adopted the proposed rules without modification.<sup>69</sup> The final rule explicitly allows interstate natural gas pipelines and electric transmission operators to share non-public operational information to promote the reliability and integrity of their systems.<sup>70</sup> To protect against undue discrimination and ensure the confidentiality of shared information, FERC approved a No-Conduit Rule that prohibits recipients of the information exchanged pursuant to the final rule from disclosing it to an affiliate or a third party. The No-Conduit Rule does not affect current communications among interstate and intrastate natural gas pipelines, local distribution companies, and gatherers regarding conditions affecting gas flows between these physically interconnected parties, nor does it affect communications between transmission system operators and load serving entities.<sup>71</sup> In response to comments, the Commission clarified that the final rule does not prohibit electric transmission operators from sharing non-public, operational information received from an interstate pipeline under the rule with a local distribution company, “if the information sharing and appropriate safeguards to prevent

inappropriate use or disclosure of shared information is separately authorized by the Commission.” As an example of a permissible disclosure, the Commission cited an ISO or RTO’s disclosure of information pursuant to a tariff filing under section 205 of the *FPA*.<sup>72</sup>

## XII. FERC Policy on Capacity Allocation for New Electric Transmission Projects

In January 2013, FERC issued a *Final Policy Statement* that clarified and refined its existing policies governing the allocation of capacity for new merchant transmission projects and new non-incumbent, cost-based, participant-funded transmission projects.<sup>73</sup>

Under the new policy, FERC now permits the following:

- Merchant transmission developers’ selecting a subset of customers (not using unduly discriminatory or preferential criteria) and direct negotiation with those customers to reach agreement on rates, terms, and conditions;
- Allocation of up to 100 per cent of transmission capacity through bilateral negotiations only after developers have (1) broadly solicited interest in the project from potential customers and (2) demonstrated compliance with the solicitation, selection, and negotiation process criteria; and
- Allocation of capacity to affiliates when done in a transparent manner that adheres to certain protections, including open solicitation.

The *Final Policy Statement* did not change the

<sup>66</sup> See generally *Coordination between Natural Gas and Electricity Markets*, FERC Docket No AD12-2-000.

<sup>67</sup> See *Order Directing Further Conferences and Reports*, 141 FERC ¶ 61,125 (2012).

<sup>68</sup> *Communication of Operational Information between Natural Gas Pipelines and Electric Transmission Operators*, 144 FERC ¶ 61,043 (2013).

<sup>69</sup> *Communication of Operational Information between Natural Gas Pipelines and Electric Transmission Operators*, 145 FERC ¶ 61,134 (2013), rehearing pending.

<sup>70</sup> *Ibid* at paras 1, 2, 7.

<sup>71</sup> *Ibid* at paras 7, 15, 16, 32 & n 27.

<sup>72</sup> *Ibid* at para 56.

<sup>73</sup> *Allocation of Capacity on New Merchant Transmission Projects and New Cost-Based, Participant-Funded Transmission Projects, and Priority Rights to New Participant-Funded Transmission*, 142 FERC ¶ 61,038 (2013).

four factors applied by FERC when it evaluates requests by merchant transmission developers for negotiated rate authority: (1) the justness and reasonableness of rates; (2) the potential for undue discrimination; (3) the potential for undue preferences, including affiliate preference; and (4) regional reliability and operational efficiency requirements.<sup>74</sup> The *Final Policy Statement* did, however, modify how FERC analyzes the second and third factors. The second and third factors will be deemed satisfied if transmission developers adhere to the guidelines set forth in the *Final Policy Statement*.

#### **A. Open Solicitation Process**

Prior to negotiating with potential transmission customers, developers are required to engage in an open solicitation process in lieu of the previous requirement of a formal “open season.” To comply with the *Final Policy Statement*, developers should include a broad notice issued in a manner that ensures that all potential and interested customers are informed of the proposed project that includes sufficient technical information and the criteria the developer plans to use to select transmission customers (e.g., credit rating, “first mover” status, and customers’ willingness to incorporate project risk-sharing into their contracts).

#### **B. Post-Selection Demonstration**

FERC continues to require merchant transmission developers to disclose the results of their capacity allocation process, though it will now be noticed and acted upon under section 205 of the *FPA*. Developers are expected to demonstrate the fairness of their process by describing the criteria used to select customers, any price terms, and any risk-sharing terms and conditions that served as the basis for identifying transmission customers.

#### **C. Non-Incumbent, Cost-Based, Participant-Funded Projects**

FERC announced that its *Final Policy Statement* also applies to new non-incumbent, cost-based,

participant-funded transmission projects. The Commission, however, acknowledged the differences between merchant transmission projects, and said it will review the transmission rate, terms and conditions, including any agreed upon return on equity, for non-incumbent, cost-based, participant-funded transmission projects more closely to ensure they satisfy precedent regarding cost-based transmission service.

#### **D. Incumbent, Cost-Based, Participant-Funded Projects**

FERC also announced that it is not changing its case-by-case evaluation of requests for cost-based participant-funded transmission projects by incumbent transmission providers. Incumbents were defined as those with a clearly defined set of existing obligations under their open access transmission tariffs with regard to new transmission development, including participation in regional planning processes and the processing of transmission service request queues. Thus, the *Final Policy Statement* does not affect incumbent transmission development for the purpose of serving native load.

### **XIII. Regulation of Ethane Pipelines**

On December 31, 2013, FERC issued an order<sup>75</sup> asserting jurisdiction over a proposed interstate ethane pipeline despite assurances that the ethane transported would be intended for non-energy, agricultural purposes. Although FERC’s jurisdiction over the Ethane Pipeline was an issue of first impression, the order’s reasoning may trump its holding in significance. FERC indicated that, going forward, it is likely to interpret its jurisdiction broadly based on the possible use of transported material rather than its intended, or even probable, use.

Williams Olefins Feedstock Pipelines, LLC (Williams) had petitioned FERC to disclaim jurisdiction over its planned Williams Bayou Ethane Pipeline (Ethane Pipeline). Williams

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<sup>74</sup> See *Chinook Power Transmission, LLC*, 126 FERC ¶ 61,134 at 37 (2009).

<sup>75</sup> *Williams Olefins Feedstock Pipelines, LLC*, 145 FERC ¶ 61,303 (2013).

represented that the Ethane Pipeline would deliver unbatched purity liquid ethane to petrochemical plants and storage facilities in Texas and Louisiana. Williams said the ethane would be used as feedstock to produce ethylene, not fuel. On this basis, Williams asked FERC to assess the “unique character” of the Ethane Pipeline by applying what Williams claimed is FERC’s “traditional test” for jurisdiction: whether the product being transported serves an energy-related, as opposed to feedstock, function.

FERC rejected Williams’ request. Describing Williams’ characterization of the jurisdiction test as “incomplete,” FERC articulated the governing test: whether the product being transported is a naturally-occurring hydrocarbon that is used or can be used for energy-related purposes, as opposed to having only a non-fuel, feedstock function. FERC said ethane is a naturally-occurring hydrocarbon with a thermal heat content that can be used for fuel, and that it is commonly blended with low Btu natural gas to increase the Btu content to make such gas marketable as fuel. FERC also noted that ethane has current energy uses and future undeveloped energy uses, as evidenced by companies’ submissions of proposals to expand LNG terminals to enable foreign export of certain propane. FERC concluded these current and potential energy uses of ethane justified assertion of jurisdiction over the Ethane Pipeline.

FERC said it “will not disclaim jurisdiction over interstate ethane transportation based on an applicant’s assertion of the intended end-use of the ethane.” FERC noted that the pipeline does not control the use of the transported products and that the use of such products can change. Given these realities, FERC said basing jurisdiction on intended end-uses of transported products could result in a “balkanized” pipeline system, with some

pipelines regulated by FERC and others not.

#### **XIV. Pipeline and Hazardous Materials Safety Administration Safety Enforcement Rule**

On September 25, 2013, the Pipeline and Hazardous Materials Safety Administration (PHMSA) published a final rule amending its administrative procedures for the pipeline safety program.<sup>76</sup> The amendments went into effect on October 25, 2013 and are intended to satisfy certain mandates in the *Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011* (*Pipeline Safety Act*).<sup>77</sup>

The *Pipeline Safety Act* directed the PHMSA to issue regulations that (1) require hearings to be convened before a “presiding official;” (2) ensure the expedited review of corrective action orders in cases where a pipeline facility is deemed to be hazardous to life, property or the environment; (3) create a separation of functions between agency personnel who perform investigatory and prosecutorial duties and those who are responsible for deciding the final outcome of cases; and (4) prohibit ex parte communications with those decision-makers.<sup>78</sup>

The *Pipeline Safety Act* doubled the maximum civil penalties that the PHMSA can impose in federal enforcement actions to \$200,000 per day<sup>79</sup> and gave the PHMSA additional authority to enforce the onshore facility response plan requirements in the *Oil Pollution Act of 1990*.<sup>80</sup>

PHMSA’s final rule addressed each of these issues. Among other things, it (1) established a new provision permitting imposition of administrative civil penalties on anyone who obstructs the conduct of a pipeline safety investigation or inspection; (2) specified the materials to be provided in the case file for an enforcement action; (3) implemented

<sup>76</sup> *Pipeline Safety: Administrative Procedures; Updates and Technical Corrections*, 78 Fed Reg 58897 (2013) (codified at 49 CFR pts 190, 192, 193, 195, and 199).

<sup>77</sup> *Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011*, Pub L No 112-90, 125 Stat 1904 (codified at 49 USC §§ 60101-60138).

<sup>78</sup> *Ibid* § 20, 125 Stat 1916.

<sup>79</sup> *Ibid* § 2(a), 125 Stat 1905.

<sup>80</sup> *Ibid* § 10, 125 Stat 1912.

the *Pipeline Safety Act*'s mandates relating to the separation of functions and prohibitions on ex parte communications; (4) extended PHMSA's enforcement proceedings to alleged violations of the onshore facility response plan requirements in the *Oil Pollution Act of 1990*; (5) defined the presiding official's duties and powers; and (6) increased the maximum civil penalties for safety violations.<sup>81</sup> ■

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<sup>81</sup> See generally 78 Fed Reg 58897 at 58899-12.

# ONTARIO ENERGY LAW: ELECTRICITY

by Clark, Ron W., Stoll, Scott A., and Cass, Fred D.  
Markham: LexisNexis Canada, 2012

*Reviewed by Helen T. Newland\**

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This book comprises a “soup to nuts” survey of the Ontario electricity sector, presented in nine chapters over 600 pages. Although the book describes the evolution of the industry in Ontario over the last century, its principal focus is on developments in the decade following the enactment of the *Energy Competition Act*, 1998 which restructured government-owned Ontario Hydro as part of a larger plan to move to a market-based, competitive electricity market. The three co-authors – Ron Clark, Scott Stoll and Fred Cass – are lawyers who have practiced almost exclusively in the energy area for their entire careers.

One third of the book – 200 pages – is devoted to electricity generation. This section includes a high level description of the technologies that underpin Ontario’s supply mix (nuclear, fossil, renewable); narratives about the Ontario Energy Board’s (OEB) generation licensing regime and the Independent Electricity System Operator’s Market Rule requirements; and discussions about the roles of Ontario Power Generation and the Ontario Power Authority (“OPA”). In light of Mr. Clark’s work for the OPA, it is not surprising that over 150 pages are devoted to the OPA’s various energy procurement initiatives, starting with the competitive procurement of 2,500 MW of clean generation and demand side projects in 2004.

This section includes useful summaries of the key provisions of the power purchase contracts for each such initiative, including the Renewable Energy Supply or “RES” Contracts, the Renewable Energy Standard Offer Contracts and the various iterations of the Feed-in-Tariff (“FIT”) Contracts.

The balance of the book comprises five chapters that deal with: electricity markets and system operation; distribution; transmission; conservation and demand management; and compliance and enforcement, respectively. None of these areas are covered in any detail. Rather, these chapters provide high level overviews of underpinning legal and policy frameworks and regulatory requirements.

Two emerging areas – the storage of electricity and the opportunities and pitfalls associated with the wide-spread deployment of smart meters – are only touched on in the book. Both topics warrant more discussion. Electricity storage is increasingly seen as a valuable tool to address fluctuating power supply and demand levels. A discussion of how the procurement of electricity storage technologies would fit into the current regulatory framework would have been useful. Smart meters collect a wide range of data about customer consumption and, thus, customer behaviour. At the level of the individual consumer, this has the potential of

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triggering privacy concerns about the misuse of information; however, on an aggregated basis, the sale of such data could generate additional revenue and potentially offset rising distribution rates. A discussion of these issues would have been useful and topical.

This book is more a 10-year survey of the Ontario electricity sector than a detailed and current reference guide. Indeed, portions of it are already out-of-date; for example, the book does not deal with the 2012 change to the federal environmental assessment process, the fundamental changes to the FIT program that occurred in early 2013 or the recent OEB decision on Ontario's first competitive process to select a proponent to develop a large-scale transmission project. For these reasons, while this book would be useful to readers unfamiliar with the Ontario electricity sector who wish to come "up to speed" quickly and relatively painlessly, such as newly qualified lawyers, it would have less utility for experienced lawyers and consultants who are familiar with Ontario energy markets. ■

# LET THE EASTERN BASTARDS FREEZE IN THE DARK: THE WEST VERSUS THE REST SINCE CONFEDERATION

by Mary Janigan  
Toronto: Alfred A. Knopf Canada, 2012

Sean Conway\*

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**The West Wants In!** How many times have we heard that complaint in the Canadian political debate?

The rise of the Reform Party in the 1990s and the triumph of Harper Conservatism which followed, suggests that Western Canada is playing a fundamentally different – and more important – role in our national affairs today that at any time in our nation's history. To many central and eastern Canadians who have long ruled the federal roost at Ottawa, the evidence abounds that 'The New West' is now in charge.

Relations between Western Canada and the rest of the country is the subject of an important and lively new book from the pen of one of Canada's most accomplished writers, Mary Janigan. *Let the Eastern Bastards Freeze in the Dark: The West Versus the Rest Since Confederation* chronicles the long and arduous campaign for Manitoba, Saskatchewan and Alberta to secure full control of their public lands and natural resources. Surprising as it might seem to modern-day Canadians, the three prairie provinces did not enter the federation on the same terms and conditions as did the other provinces.

The newly-minted Dominion of Canada acquired the vast territory known as Rupert's Land in 1869 from the Hudson's Bay Company for three-hundred thousand pounds. This was Canada's version of the Louisiana Purchase, that real estate deal in 1803 by which Thomas Jefferson bought half a continent from Napoleon Bonaparte. The purchase of Rupert's Land would ultimately provide the land base for the future provinces of Manitoba, Saskatchewan and Alberta. Of course, none of the local inhabitants of Rupert's Land was consulted about this land deal. Nor did they understand what a new Canadian order of things might mean for their traditional way of living on the Great Plains. Ottawa wanted 'a land bridge' to the Pacific shore to anchor Canada from 'sea to sea' and to secure the land on which to build a Pacific railway along an all-Canadian route.

Among the many strengths of Janigan's account is how well she describes the federal view of nation building and how this attitude clashed with the regional realities of Western Canada. In the early days of Confederation, the new federal government in Ottawa had big plans but little money. One source of currency was this newly-acquired western land with which

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Ottawa could pay for its transportation and settlement policies. The ink was not yet dry on the Rupert's Land deal when the Métis of the Red River Valley clashed with Canadian surveyors and land-hungry settlers who demonstrated little or no respect for Métis land title. Soon what became known as Manitoba was ablaze with rebellion and Louis Riel became the first in a long line of western leadership voices to protest the insensitive behaviour of the national government in Ottawa. He condemned the condescending attitude and the confiscatory approach the federal government took towards the legitimate needs of these rapidly developing Prairie communities.

Shortly before Saskatchewan and Alberta were created as provinces in 1905, the premier of the North-West Territories, Frederick Haultain complained bitterly to Laurier's Interior Minister Clifford Sifton that "all of our public revenues go to swell the Consolidated Revenue Fund of Canada, our public domain is exploited for purely federal purposes, and we are not permitted to draw on our future." The stylish and sometimes irascible Haultain made plain to federal authorities, "The West wanted equal rights with the other provinces. It wanted control of its lands and resources in the West, by the West and for the West. And it wanted compensation for the lands and resources that Ottawa had already used for purely federal purposes." Clifford Sifton adamantly rejected this 'local' view of resource transfer to western provinces, though in one of those strange ironies of history, Sifton's older brother Arthur would soon be the premier of Alberta making the Haultain argument to the federal government.

What is quite extraordinary in Janigan's telling of this tale is the extent to which many in the 'rest of Canada' took the view that 'we bought the West fair and square' and there could be no transfer of lands and resources to these new provinces like Alberta and Saskatchewan without the consent of the other provinces. Janigan makes the point repeatedly that the Maritimers were particularly hostile to equal treatment of the West. The venerable George Murray, longtime Liberal premier of Nova Scotia wrote to his fellow Nova Scotian

Conservative Prime Minister Robert Borden in 1914 telling him that 'the western provinces did not own their resources, Ottawa had rightly retained control because of the very significant development responsibilities like immigration on which the federal government had to spend so liberally.' Moreover, the Nova Scotia premier declared that these complaining western provinces were receiving "very generous" federal subsidies especially when compared with Maritime subsidies.

Federal-provincial meetings on the question of western lands and resources generally brought out the worst in Canadian statecraft. Janigan provides a detailed description of the conference held in Ottawa just after the Great War formally ended in November 1918. The author sets up this colourful and contentious conference by reminding the reader that the West had made a contribution to the war effort well beyond its regional weight within the federation. This support for the war effort counted for little as the 'Gang of Three' – the premiers of Manitoba, Saskatchewan and Alberta – confronted the front line of federal cabinet authorities – Finance Minister Thomas White and Interior Minister Arthur Meighen – who brought with them an impressive array of research analysis on the issues at hand.

Almost immediately, the conference dissolved into an intergovernmental morass as Ottawa revealed that it had no money to ease the pain and furthermore, the federal government would not make concessions to the Prairie leaders without the consent of the other premiers. The Gang of Three supported by that 'rustic sage', B.C. premier "Honest John" Oliver, were "incandescent" in their anger of this turn of events. They were not going to allow their just claims for fairness and equity to be linked to other unrelated complaints in federal-provincial relations. They vowed never to forget the shoddy treatment they received that week in November as the world returned to peace and Western Canada was about to erupt in agrarian revolt and labour unrest.

Anyone who remembers those fractious first ministers' meetings of the Trudeau era will certainly recognize this script. But for any

Western Canadian reading *Let the Eastern Bastards Freeze in Dark*, the resistance of the rest of Canada to a genuine plea from Westerners for fairness and equity will be a reminder of how dangerous and destabilizing are the regional tensions within the Canadian federal state. As Janigan observes ruefully but relevantly toward the end of this saga, “our regional identities have almost subsumed any national identity” and “our regions define themselves by their grievances.”

In the end, the man who led the way to finally resolving this thorny issue was William Lyon Mackenzie King. After nearly 70 years of ‘The West’ battling ‘The Rest of Canada’, King cautiously negotiated settlements with the three western provinces by 1930. Mackenzie King was a politician who, according to Janigan “regarded compromise as an evangelical virtue.” For several years during the 1920s, “he had wheedled and stalled and charmed and blackmailed his fellow first ministers.” The wily and patient King did so as he and his federal colleagues came to understand that Ottawa was now paying more for the management of these western resources than the federal government received in royalties and other revenues.

Not well known is the fact that as King moved to conciliate and settle this irritant of Canadian federalism, he was actually a member of Parliament from Saskatchewan. He firmly believed that the Liberal Party of Canada was an instrument of national unity resting on the twin pillars of Quebec and Saskatchewan. For the fussy Mackenzie King, whose professional past had been in the area of labour management relations, the final resolution of these endless firefights over land and resources was “a miracle of Confederation” informed by “divine providence” and paid for with generous dollops of federal largesse.

But the story does not end happily in 1930 for soon, the Great Depression would be spreading its dust, debt and despair across the region. Prairie governments “were reeling, frantic for cash” and it was soon clear that “resource control had brought no flood of instant riches.” Ironically, by the late 1930s, a desperate Alberta was offering to give back to Ottawa

some of its recently-won resource rights for federal fire protection of provincial lands and forests. “Luckily for Alberta” Janigan opines, “this proposal died” for within the decade, the modern oil boom was underway thanks to the rich discovery at Leduc in 1947.

In Canada’s Centennial Year, Alberta Premier E.C. Manning could report that his provincial treasury had received \$2.25 billion in oil and gas revenues since the first days of Leduc in 1947. It was, says Janigan, “a huge windfall” that few participants at that disastrous federal-provincial conference in November 1918 could ever have imagined. But thanks to the persistence of earlier Prairie leaders with names like Riel, Haultain, and Arthur Sifton to name but three, Western Canada could finally enter the promised land of sustained growth and economic diversity.

*Let The Eastern Bastards Freeze in the Dark* is a painful yet powerful tale well told and well documented. I would guess it is a tale almost completely unknown and unimaginable to most Canadians today. The concept of Canada, as a peaceable kingdom, and the land of fairness and equity is substantially renovated in this Janigan thesis. It is clear that many east of the Ontario/Manitoba border imagined a very different kind of country than those who inhabited the Great Plains. Louis Riel was not alone in his protest about ‘what kind of nation’ were we really creating with this Confederation scheme of ours? One reads Janigan and somehow the National Energy Program of the early 1980s acquires new meaning.

Yes, the West really did want in for a very long time. But the early and majority shareholders in the Canadian federation determined that the West would not be allowed in on ‘equal terms’. Mary Janigan reminds us in this fascinating account that Canada really is a ‘very fine balance’ and that the history of our resource development has often disturbed that balance with negative and lasting consequences. ■