ENERGY REGULATION QUARTERLY

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MISSION STATEMENT

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

EDITORIAL POLICY

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

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

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

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

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

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

The mission of *Energy Regulation Quarterly* is to provide a forum for debate and discussion on issues surrounding the regulated energy industries in Canada, to create a better understanding of the issues and to identify trends. As Managing Editors of *ERQ*, we believe that in pursuing this purpose we should offer a variety of articles and comments that, together, are informative, analytical, forward-thinking and reflective. The contributions in this issue of *ERQ* reflect this approach.

William Lahey's article on "The Contributions of Utilities Regulation to Electricity System Transformation: The Case of Nova Scotia" offers valuable insights into the indispensable role of sound regulation in implementing fundamental shifts in energy policy. Nova Scotia has occupied a somewhat unique position in Canada's energy supply picture. As recently as 2007, 90 per cent of the province's electricity supply came from fossil fuels, mostly coal. At the same time, the province had little interconnection with the North American electricity grid. Lahey reports that the system is now on track to meet a Renewable Energy Standard (RES) of having 40 per cent of electricity come from renewable sources by 2020. Nova Scotia is also becoming a Canadian leader in electricity system demand-side management (DSM). This transformation of the electricity system is being driven by the combined effect of environmental and electricity system legislation.

Lahey concludes that the Nova Scotia Utilities and Review Board (NSUARB) has played a "catalytic role" in bringing about this transformation. He identifies specific elements of the Nova Scotia experience that illustrate "the mundane but core attributes of effective regulators." In addition to emphasizing the importance of the Board's independence, he points to the crucial interaction of policy guidance from government and its implementation by the Board. His observations provide important lessons that have much wider relevance to energy regulation in Canada, particularly at a time when there is some evidence that governments are more inclined to insert themselves into roles historically reserved for regulators. In the current environment in which the energy industry and regulators face significant technological and policy change, strong regulatory leadership of the type noted by Lahey at the Nova Scotia UARB is worth noting.

Emerging challenges for the energy industry and regulators also underlie Mike Cleland's article on "Changing Energy Systems: Implications for Regulators and Policy Makers." Cleland reflects on the fundamental changes in energy delivery systems resulting from the combined effects of technology, environmental demands and growing concerns about system performance. These changes, he concludes, are "far from business as usual." Indeed, we may be "on the cusp of a true energy transformation", resulting from the convergence of several technological streams. However, the instinct of regulators, on the one hand, to confine utilities to pipes and wires and, on the other hand, the lack of understanding of the regulatory system by policy makers may combine to inhibit needed innovation. What is needed is a different sort of conversation in which the regulatory community stands back from the adversarial environment of the hearing room and in which policy makers are active participants.

One of the technological developments underlying the changes in energy delivery systems discussed in Mike Cleland's article is combined heat and power (CHP). The policy and regulatory implications are discussed in Richard Laszlo's article on "Combined Heat and Power in Ontario: policy tonic, regulatory headache." *Ontario's Long Term Energy Plan* claims that CHP can achieve up to 80 per cent overall efficiency by following the heat load from fossil fuels while generating electricity. Laszlo reports that the regulatory picture is clouded, as CHP expands the number and diversity of customers interested in self-generation and is potentially disruptive to the current electric utility business model. The article outlines the Ontario Energy Board's discussion paper on options for a fixed rate design.

A key element of a leadership role on the part of energy regulators is clear communication of the reasons for their decisions. The article on "The Joy of Decision Writing", by Mr. Justice David Brown, might appear at first to be of interest mainly to those who write decisions. In our view, however, the article should be parsed by a wider audience. Justice Brown describes what is needed by the decision-maker to write a sound regulatory tribunal decision and thereby indirectly provides guidance on how parties might present their cases.

A recurring challenge for regulators and industry in the current environment arises from the Crown's legal duty to engage in meaningful consultations with First Nations. The duty plays a crucial role in virtually every energy resource development in Canada today, while the content and practical implications of the duty continue to evolve. Hannah Roskey's article summarizes Alberta's recently-released *Guidelines on Consultation with First Nations on Land and Natural Resource Management*. ■

THE CONTRIBUTIONS OF UTILITIES REGULATION TO ELECTRICITY SYSTEM TRANSFORMATION: THE CASE OF NOVA SCOTIA

William Lahey[1]

Introduction

Nova Scotia's electricity system is undergoing significant change, particularly when measured against the history of Nova Scotia energy policy and politics.[2] In 2007, when a renewable energy goal was first enacted into law, 90 per cent of the province's electricity supply came from fossil fuels, mostly coal. The system is now on track to meet a Renewable Energy Standard (RES) of having 40 per cent of electricity come from renewable sources by 2020. Nova Scotia is also becoming a Canadian leader in electricity system demand-side management (DSM). From doing little on energy efficiency before 2009, the system now relies on energy efficiency to reduce its annual need for electricity by more than 5 per cent.

Nova Scotia's independent electricity regulator, the Utility and Review Board (the UARB or Board), has been at the centre of these developments. This article considers the role of the UARB with two objectives in mind; first, to bring attention to the role that one utilities regulator has played in a significant multi-year process of electricity system change and second, to illustrate the importance of an independent and respected regulatory process to electricity transformation at a time when such transformations are taking place - or being called for - across Canada and beyond.

The article pursues these objectives by considering the work of the UARB over the last decade in significant renewable energy, demand-side management and rate-setting cases. In general terms, this review shows how the UARB has helped to keep the process of transformation on track while ensuring it is conducted with transparency and accountability in the best interests of ratepayers. In some respects, it shows the UARB playing a catalytic role in prompting necessary policy development. It also demonstrates the UARB's responsiveness to the real challenges that Nova Scotia has faced in greening its electricity system under high electricity costs during and in the aftermath of a recession and in the midst of growing anxiety about the province's long-term economic future. Finally, and perhaps most fundamentally, the review shows how the UARB has conducted a system of regulation that enjoys the kind of credibility and respect that a regulatory system needs if it is to have the trust and confidence of those it regulates, those it protects, and ultimately of government. This depends on the substance of the Board's decision-making but equally on the Board's process, including its transparent reliance on expert advisors, the obligation to engage meaningfully with stakeholders that it places

1 Associate Professor, Schulich School of Law, School of Health Administration and College of Sustainability, Dalhousie University and Chair of the Board of Directors of Efficiency Nova Scotia and of EfficiencyOne.

2 Richard Starr, *Power Failure?* (Halifax: Formac Publishing, 2011).

on those it regulates and the clear, detailed and thorough reasons it provides for its decisions.

In these respects, the suggestion here is not that the UARB has been exceptional or especially innovative or creative. The point instead is to emphasize that it has consistently demonstrated the mundane but core attributes of effective regulators, including fairness, objectivity, technical competency, dependability, predictability, responsiveness, practicality, judgment and accountability. In consequence, the role the UARB has played in Nova Scotia illustrates the crucial contribution that good and stable regulation can make to the successful implementation of large-scale change in energy system policy (in this case major changes to electricity system policy) that can only be implemented over the mandates of different governments, in the face of considerable uncertainty and despite significant and often contested changes in the economic, technological, environmental and social conditions under which policy is originally established. At the same time, the success of the UARB shows that the governance of the electrical system in Nova Scotia has benefited significantly from the confidence it has placed in the UARB. This perhaps serves as a reminder that the effectiveness with which regulators discharge their mandates is the best contribution they can make to the preservation of the independent mandates on which effective regulation ultimately depends.

The Electricity System, UARB, Legislative Framework and System Transformation

Nova Scotia's Electricity System

Nova Scotia's electricity system serves 400,000 customers who consume 10,467 gigawatt hours (GWh) of electricity.[3] Roughly 90 per cent of the system, which has an installed capacity of 2,730 megawatts (MW), is owned and operated by Nova Scotia Power (NSP). NSP is a vertically integrated utility that is investor owned through the holding company called Emera. Until recently, the system obtained roughly 90 per cent of its power from burning coal and other fossil fuels in generating stations owned by NSP. The system has only limited connection to the North American grid through an intertie at Nova Scotia's border with New Brunswick which is used, among other things, to manage peak demand in each of those provinces.

Since 2010, the electricity sector has included Efficiency Nova Scotia Corporation (ENSC). It is a statutory corporation established by the *Efficiency Nova Scotia Corporation Act*[4] with the mandate to administer energy efficiency and conservation programs, including DSM programs in the electricity sector.[5]

The Utility and Review Board

NSP and ENSC are both regulated by the UARB, a quasi-judicial regulatory body established under the *Utilities and Review Board Act*.[6] By any measure, the UARB qualifies as a "super-regulator". In addition to being the regulator in the electricity sector, it is also the regulator of gas and water utilities. It also has regulatory responsibilities in auto insurance, liquor licensing, gaming, pay day loans, retail petroleum pricing, public passenger carriers, and provincial railways. It has adjudicative functions in the fields of property assessment, criminal injuries, expropriation, film classification, fire safety, municipal and school board boundaries and municipal planning.

For both NSP and ENSC, the UARB is given its regulatory mandate by the *Public Utilities Act*,[7]

3 For information in this paragraph, see London Economics, *Nova Scotia power sector: Current Situation, recent developments and challenges, and SWOT analysis*, a paper prepared for the Nova Scotia Department of Energy, online: Nova Scotia Department of Energy <http://energy.novascotia.ca/sites/default/files/files/Overview%20web2.pdf>.

4 *Efficiency Nova Scotia Corporation Act,* SNS 2009, c 3.

5 Under recently adopted restructuring legislation, the administration of DSM programs for the electricity sector will be franchised by the Province to a franchisee that will conduct business as an energy efficiency utility under the brand Efficiency Nova Scotia. ENSC is in the process of being reconfigured as a corporation under the Canada Not-for-Profit Corporations Act, called EfficiencyOne, in the expectation it will be awarded the franchise to carry on as the administrator of demand-side management programs as Efficiency Nova Scotia. It will do so as the supplier of energy savings to NSP which NSP will be obligated under the Electricity Act to purchase to the extent energy savings are shown to be the most cost-effective energy resource for ratepayers.

6 *Utilities and Review Board Act,* SNS 1992, c 11.

7 *Public Utilities Act,* RSNS 1989, c 380[*PUA*].

supplemented in the case of NSP by provisions of the *Electricity Act*[8] and its *Regulations* and in the case of ENSC by the provisions of the *Efficiency Nova Scotia Corporation Act*.[9] This will soon change when the proclamation of recently passed restructuring legislation adds provisions to the *Public Utilities Act* and the *Electricity Act* to make the franchisee of the Efficiency Nova Scotia brand into an energy efficiency utility and a supplier of cost-effective energy-efficiency to NSP under the oversight of the UARB.[10]

Within these statutory parameters, the mandate of the UARB is that of a traditional economic regulator of monopolistic suppliers of utility services. Its core responsibility is to pre-approve the "schedule of rates, tolls and charges" that can be charged to customers for utility services.[11] In carrying out this responsibility, the UARB uses the "cost-of-service" model of economic regulation[12] subject to a statutory requirement that tolls, rates and charges be charged equally to all persons under "substantially similar circumstances" as determined by regulations made by the UARB.[13] The approval of the UARB is also required for capital expenditures greater than $250,000.[14] The UARB also has the responsibility to fix and determine the rate base of a public utility and to determine the "just and reasonable" rate of the annual return the utility is entitled to earn on its rate base.[15] More broadly, the UARB has the "general supervision of all public utilities"[16] and the authority to make such orders "as it deems just in respect of tolls, rates and charges to be paid to any public utility for services rendered or facilities provided".[17] In respect of DSM, these responsibilities and powers were supplemented by the requirement placed on ENSC by the ENSC Act to submit an "electricity demand-side management program" to the UARB for its approval.[18]

The Legislative Framework of Energy Policy

The transformation of the electricity system is being driven by the combined effect of environmental and electricity system legislation. Since 2005, NSP has been subject under *Air Quality Regulations*[19] made under the *Environment Act*[20] to escalating emission limits out to the year 2020 and beyond for sulphur dioxide, nitrogen oxide and mercury. In 2007, the goal of having at least 18.5 per cent of electricity generated from renewable sources by 2013 was included in the list of twenty-one environmental performance goals set out in the *Environmental Goals and Sustainable Prosperity Act*.[21] In 2009, *Greenhouse Gas Emissions Regulations*[22] made under the *Environment Act*[23] imposed increasing greenhouse gas emission caps on NSP out to the year 2030. Renewable Energy Standards became applicable to NSP in 2010 under regulations made under the *Electricity Act*.[24] These require 10 per cent or more of the total electricity supplied in 2013 and 2014 to be "renewable low-impact electricity" produced by "renewable low-impact generation facilities";[25] 25 per cent or more

8 *Electricity Act,* SNS 2004, c 25.

9 *Supra* note 3.

10 *Electricity Efficiency and Conservation Restructuring (2014) Act*, SNS 2014, c 5.

11 *PUA*, *supra* note 6 s 64.

12 *Re Nova Scotia Power Inc.*, 2005 NSUARB 27 at para 24.

13 *Ibid* at para 67.

14 *Ibid* at para 35.

15 *Ibid* at para 45.

16 *Ibid* at para 18.

17 *Ibid* at para 44.

18 *Supra* note 3 s 35.

19 *Air Quality Regulations,* OIC 2005-87, NS Reg 28/2005.

20 *Environment Act,* SNS 1994-95, c 1.

21 *Environmental Goals and Sustainable Prosperity Act,* SNS 2007, c 7.

22 *Gas Emissions Regulations,* OIC 2009-341, N.S Reg 260/2013.

23 *Supra* note 19.

24 *Renewable Electricity Regulations*, OIC 2010-381, NS Reg 155/2010 [*Renewable Electricity Regulations*]. See also Nova Scotia Department of Energy, *Renewable Electricity Plan: A Pathto Good Jobs, Stable Prices, and a Cleaner Environment*, April, 2010.

25 The planning to meet this obligation is required to exclude electricity from "distribution system connected renewable energy generators". The 10% of supplied renewable electricity is required to include 5% of its total annual sales from independent power producers. See *Renewable Electricity Regulations*, *Supra* note 23, s 5.

of the total electricity supplied from 2015 to 2020 to be renewable electricity, including an additional 300 GWh to be acquired from independent power producers;[26] and 40 per cent or more of the total electricity supplied in 2020 and in each subsequent year to be from renewable electricity.[27]

Another critical piece of the legislative framework is the *Equivalency Agreement* between Nova Scotia and Canada that was negotiated in 2012 and executed in 2014.[28] Under this Agreement, what is required of Nova Scotia's electricity system relative to the reduction of greenhouse gas emissions by Nova Scotia laws, particularly the *Environment Act* and the *Greenhouse Gas Emission Regulations*, is stipulated to be equivalent to what would be required of Nova Scotia's electricity system by the provisions of the *Canadian Environmental Protection Act*[29] and the *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations*[30] made under that Act. This has given the policy of electricity system transformation under way in Nova Scotia an additional level of non-negotiability. It has also avoided a significant cost to ratepayers that would have otherwise been incurred to close coal-fired generating plants that compliance with the federal regulations would otherwise have required.

Electricity System Transformation in Nova Scotia

Currently, the system uses slightly more than 1,000 GWh of renewable energy that is compliant with the province's 10 per cent renewable energy standard for 2013.[31] To meet the 2020 target, more than 4,000 GWh of RES compliant renewable energy will be required. It is projected to come from multiple supply sources including more than 1,300 GWh from wind projects built after 2001, 357 GWh from a single significant biomass project, and at least 1,135 GWh of hydro-electric power which will be transmitted from the Muskrat Falls project in Labrador to Nova Scotia by the Maritime Link, a transmission cable being laid between Newfoundland and Nova Scotia. The Muskrat Falls\Maritime Link project will be transformational in another respect: it will end Nova Scotia's isolation as an "electricity island" by interconnecting it more fully into the North American grid. It therefore creates the potential for further and perhaps deeper transformational change beyond 2020.

In parallel to this significant action on the sourcing of electricity, Nova Scotia has rapidly become a Canadian leader on energy efficiency and conservation in the electricity sector.[32] From doing little efficiency and conservation before 2008, Nova Scotia's electricity system has since 2011 been investing roughly $40 million per year into efficiency and conservation programs that are administered by ENSC. These programs are now producing a level of electricity savings as a proportion of electricity consumed that is the highest in Canada and comparable to that being produced in leading American jurisdictions, most of which have been working on energy efficiency and conservation on a sustained basis for much longer. These savings have been produced at a unit cost that is comparable or below the unit cost of savings in other jurisdictions. By 2013, due to efficiency and conservation efforts, electricity use in Nova Scotia was 5.5 per cent below what it would otherwise have been.[33]

26 As with the 2011 standard, the planning to meet this obligation must exclude electricity from "distribution system connected renewable energy generators", although such electricity can be taken into account in meeting the obligation. The 25 per cent of supplied renewable electricity is required to include 5 per cent of total annual sales purchased from independent power producers. *Renewable Electricity Regulations*, *Supra* note 23 s 6.

27 The 40 per cent must include renewable energy acquired through continuing compliance with obligations from the earlier phases requiring the purchase of renewable energy from independent producers. The 40 per cent is required to include 20 per cent of the electricity generated by the Muskrat Falls Generating Station if the station and associated transmission infrastructure has been completed and if an assessment against NSP in relation to the Maritime Link project has been approved by the UARB. *Renewable Electricity Regulations*, *supra* note 23 s 6A.

28 An Agreement on the Equivalency of Federal and Nova Scotia Regulations for the Control of Greenhouse Gas Emissions from Electricity Producers in Nova Scotia, online: <http://www.ec.gc.ca/lcpe-cepa/default.asp?lang=En&n=1ADECEDE-1>.

29 *Canadian Environmental Protection Act,* SC 1999, c 33.

30 *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations,* SOR/2010-138.

31 See London Economics, *Nova Scotia power sector: Current Situation, recent developments and challenges, as SWOT analysis – Prepared for the Nova Scotia Department of Energy* (2014), throughout but especially at 31-34.

32 ICF International, Emerging Electricity Technologies in Nova Scotia (2014), 1-2 and 41-47.

33 Efficiency Nova Scotia Corporation, 2013 Annual Report, 6.

Vol. 2 - Article - W. Lahey

The Role of the UARB and of the Regulatory Process in System Transformation

Setting the Stage – The 2005 and 2006 General Rate Increase Decisions

The transformation of the Nova Scotia electricity system can be dated from the adoption of the *Air Quality Regulations* in 2005. These marked not only a shift in the content of Nova Scotia's environmental policy in relation to NSP but also a shift in approach to implementation of that policy. For the first time, Nova Scotia had put policy commitments that entailed significant change in how electricity was to be produced into law.

It therefore makes sense to start any consideration of the role that the UARB has played in system transformation from that same year, 2005. In that year, the UARB made the first of two significant decisions on back-to-back applications by NSP for general rate increases in the vicinity of 10 per cent.[34] Neither application dealt very directly with the shift to renewable energy or with DSM but, like the subsequent rate increase applications to come in 2008 and 2012, those of 2005 and 2006 focused attention on the vulnerability of electricity consumers to significant rate increases driven inexorably by increases in the cost of coal and other fossil fuels. They therefore focused attention on the economic and consumer protection rationales for diversified generation and DSM.

The 2005 and 2006 applications also tested the capacity of the regulatory system to deal with economic realities in the context of wide-spread anger with NSP as well as government over the rising cost of electricity to households and businesses and growing frustration with the limited progress on environmental issues and the impact of electricity prices on low-income households. This context was brought directly to bear on the work of the UARB. For example, there were 37 formal intervenors in the Board's hearing on the 2005 rate application, all but two opposing the application.[35] In that hearing and the hearing on the 2006 application, as well as in subsequent hearings, significant roles were played by intervenors focused on the environmental, low income and consumer issues.

In both the 2005 and 2006 decisions, the UARB approved significant rate increases for NSP that were at the same time, significantly below the increases applied for. In both, it subjected NSP to strong criticism of its fuel purchasing practices and more generally to detailed scrutiny of the company's expenditures in areas such as OM&G expenses and executive compensation. For the purpose of this article, the more immediate interest are the steps that the UARB took in these decisions towards establishing a process or model of regulation that the Board has continued to develop while being guided by it in subsequent cases, including cases on renewable energy and DSM. For example, in the hearing leading up to the 2005 decision, the Board appointed a Consumer Advocate who immediately played a significant role in the hearing.[36] Soon afterwards, the position of Consumer Advocate was established in legislation[37] and since has become a leading player in all of the Board's hearings on electricity matters and in the broader process of consultations and engagement that the Board now routinely expects of both NSP and ENSC.

The 2005 decision was also significant for the Board's rejection of a proposed settlement agreement between NSP and the majority of intervenors, including the Province.[38] The reason was substantive: the inconsistency of the proposed settlement with the Board's assessment of the evidence before it, including the evidence on the prudence of NSP's fuel purchasing practices. But the Board also endorsed the concerns of some intervernors, including those representing consumers and low-income ratepayers, on the under-inclusiveness of the process by which the agreement has been negotiated. In subsequent proceedings, the Board has encouraged settlement discussions and the broader process of open and transparent engagement with stakeholders that can lead to settlement agreements, but subject to the parameters laid out in the 2005 and later

34 *Re Nova Scotia Power Inc.*, 2005 NSUARB 27 (CanLII).

35 *Ibid* at para 6.

36 *Ibid* at para 29.

37 *PUA*, *supra* note 6 s 91.

38 *Re Nova Scotia Power Inc.*, 2005 NSUARB 27 (CanLII), at paras 37-46.

decisions. Where it has approved a settlement agreement, it has done so because it approves of how the agreement addresses the issues that would otherwise be in dispute.[39]

Demand-Side Management

In the 2006 rate decision, the UARB declined NSP's application for funding to implement a DSM plan and instead determined that a separate hearing on DSM was needed.[40] This responded to a generally critical reception among intervenors on the plan which NSP had proposed, including of the process that NSP had used to develop its plan. One of the questions raised, including by the Consumer Advocate and environmental and low-income advocates, was whether NSP would be in a conflict of interest as the administrator of DSM given its core business was to sell electricity.

Before the planned hearing on DSM could occur, the UARB directed NSP to complete an Integrated Resource Plan (IRP).[41] The rationale was to give the Board and stakeholders a sense of the overall strategic plan under which to consider NSPI's applications for capital projects and DSM. The UARB-approved Terms of Reference for the development of the IRP stipulated that "stakeholders" were to be an "integral part" of the process. The IRP concluded that the most cost-effective options for reducing emissions and meeting forecasted increases in customer load were investments in DSM and renewable energy as well as upgrades to the utility's existing facilities. This led to a DSM program development process under UARB-approved Terms of Reference that called for collaboration between NSP, Board staff and consultants and stakeholders. The strength of stakeholder opposition to NSP assuming the role of DSM administrator became obvious. A separate stakeholder engagement process on the question of how DSM programming was to be administered and governed was established by the Province. The outcome was a recommendation for the creation of a new stand-alone independent DSM administrator.[42] The legislation establishing ENSC was passed in 2009 and proclaimed in 2010.

Meanwhile, in 2008 the UARB approved a $12.9 million DSM Plan developed by NSP for 2008-2009 by approving a Settlement Agreement which described NSP "temporary DSM administrator".[43] One of the significant elements of the approved settlement was the formation of a DSM Program Development Working Group to be chaired by a consultant to the UARB. This Working Group, now chaired by ENSC, has ensured a high level of input into subsequent DSM Plans by participants in the regulatory process and consequently a high level of stakeholder confidence in the DSM planning process. Another significant outcome of the 2008 decision was the UARB's acceptance of submissions from the Consumer Advocate and the Ecology Action Centre that performance of DSM programs be subject to evaluation by an independent evaluator appointed by the DSM administrator and verified by a UARB consultant. Together, these two outcomes of the 2008 DSM decision have done much to ensure rigour and accountability in the planning and administration of DSM and stakeholder confidence in the energy savings achieved. Since the 2008 decision, the UARB has approved five further DSM plans.[44]

Renewable Energy

UARB decisions have also played a critical role in guiding the development of renewable energy. For example, under the *Renewable Energy Regulations* made under the *Electricity Act*,[45] it issued a major policy-setting decision on renewable energy community based feed-in tariffs and one on tidal energy feed-in tariffs in 2013.[46] In both, the hearing flowed from a successful consultative tariff development process conducted by UARB consultants, Synapse. Cases on the standard form of Power Purchase Agreements and on significant wind projects have also come before the Board[47]

The Board's most significant renewable energy decision has been its decision on the Maritime Link Project, which has already been discussed in this Journal.[48] It presented the UARB with difficult and challenging issues at the intersection of regulation, policy and politics.

The project involves the laying of a transmission line between Newfoundland and Nova Scotia.[49] It will have the capacity to carry more than 4 terawatt hours (TWh) of electricity produced by new hydro-electric damns in Labrador, including one being built at Muskrat Falls, from Newfoundland to Nova Scotia. More than 3 TWh of the electricity will be transmitted through New Brunswick to New England. Under agreements with Nalcor, Newfoundland's crown-owned utility, an affiliate of NSP called NSP Maritime Link Incorporated (NSPML) is paying 20 per cent of the cost of Muskrat Falls and of the Maritime Link. In exchange, Nalcor is committed for 35 years to providing Nova Scotia with 20 per cent of the electricity produced by Muskrat Falls plus an additional 240 of gigawatt-hours (GWh) of electricity per year in the first five years of the Link's operation for use in Nova Scotia.

The issue for the UARB was whether NSPML's investment into the project should be recoverable from Nova Scotia ratepayers. This was put to the Board under the *Maritime Link Act*[50] and the *Maritime Link Cost Recovery Process Regulations* which stipulated that the UARB was to approve the project if satisfied of two matters: that the project represented the lowest long-term cost alternative for electricity for Nova Scotia ratepayers and that the project was consistent with NSP's legislated obligations under the *Electricity Act*, the *Environment Act*, the *Canadian Environmental Protection Act*.[51] The Regulations also imposed a mandatory timeline on the Board's consideration of the project of 180 days from the date of its submission.

The UARB concluded that the Maritime Link project was consistent with NSP's obligations under the specified legislation.[52] It also concluded that the project was the lowest long-term cost alternative for ratepayers "but not on an overwhelming basis".[53] This was because there were other alternatives for meeting the legislated obligations that performed as well or even better on some future scenarios. Nevertheless, the Board concluded that the Maritime Link project was "slightly more robust than the various alternatives" and it "does edge out other alternatives".[54] Approval was however subject to an important condition: that NSPML obtain a right to access market-priced energy from Nalcor in addition to the energy that would be supplied under the "20 for 20 principle" when it was needed to economically serve NSP ratepayers.[55] This condition reflected the Board's conclusion that the availability of market-priced energy via the Link was "crucial to the viability of the ML project as against the other alternatives".[56] It was also consistent with the evidence presented

39 *Re Nova Scotia Power Inc.*, 2008 NSUARB 140 (CanLII), at paras 9-22.
40 *Re Nova Scotia Power Inc.*, 2006 NSUARB 23 (CanLII), at paras 437-76.
41 These developments are summarized in *Re Nova Scotia Power Incorporated's Demand Side Management Plan*, 2008 BSUARB 47 (Can LII).
42 David Wheeler, *Stakeholder Consultation Process for an Administrative Model for DSM Delivery in Nova Scotia – Final Report* (Dalhousie University, 2008), online: <http://0-fs01.cito.gov.ns.ca.legcat.gov.ns.ca/deposit/b10579424.pdf>.
43 *Re Nova Scotia Power Incorporated's Demand Side Management Plan*, 2008 BSUARB 47 (Can LII).
44 *Re Nova Scotia Power Incorporated*, 2009 NSUARB 166 (CanLII); *Re Nova Scotia Power Incorporated*, 2010 NSUARB 155; *Re Efficiency Nova Scotia Corporation*, 2011 NSUARB 99 (CanLII); *Re Efficiency Nova Scotia Corporation*, 2012 NSUARB 209 (CanLII); and *Re Efficiency Nova Scotia Corporation*, 2014 NSUARB 144 (CanLII). Due to the fact that ENSC was not established in law until 2010 and did not become operational until relatively late in 2010, DSM Plans for 2010 and 2011 were also developed and submitted for UARB approval by NSP: see.
45 *Renewable Electricity Regulations, supra* note 23. .

46 *Re Renewable Energy Community Based Feed-In Tariffs*, 2011 NSUARB 100 (CanLII); *Re Tidal Energy Feed-In Tariffs*, 2013 NSUARB 214 (CanLII).
47 *Re Standard Form Power Purchase Agreement for 300 GWh of Renewable Energy from Independent Power Producers*, 2012 NSUARB 49 (CanLII); *Re Nova Scotia Power Inc.*, 2013 NSUARB 92 (CanLII). The latter was for approval of capital expenditure on the South Canoe wind project. In the case on the Power Purchase Agreements and in the cases on feed-in tariffs, the UARB has reviewed the work of the Renewable Energy Administrator, including its procedural aspects. The Renewable Energy Administrator's statutory mandate is to oversee the competitive bidding process for the procurement of renewable sources of power from Independent Power Producers.
48 Rowland Harrison, Nova Scotia Maritime Link Decision" (2013) 1 *Energy Regulation Quarterly*, 65.
49 *Re NSP Maritime Link Incorporated*, 2013 NSUARB 154 (CanLII), at paras 9-47.
50 *Maritime Link Act,* SNS 2012, c 9.
51 *Canadian Environmental Protection Act,* OIC 2012-326, NS Reg 189/2012 s 5.
52 *Re NSP Maritime Link Incorporated*, 2013 NSUARB 154 (CanLII), at paras 232-40.
53 *Ibid* at paras 170-72.
54 *Ibid* at para 173.
55 *Ibid* at paras 226-30.
56 *Ibid* at paras 223.

by NSPML, which was that additional market-priced energy would be available to Nova Scotia if the Link was constructed.

The Premier of Newfoundland and Labrador, which did not submit the larger project to its regulator, and the Premier of Nova Scotia responded to the UARB's conditional approval of the ML project by stating that the project did not depend on UARB approval. Despite this, Emera, Nalcor and NSPI negotiated an Energy Access Agreement (EEA) to address the condition that Nova Scotia have a right of access to market-priced energy from Nalcor. It was submitted to the UARB as a compliance filing by NSPML in late 2013. Essentially, the Agreement obligates Nalcor to make available a cumulative total over 24 years of 28.8 TWh of market energy and a yearly average of 1.2TWh by offering up to 1.8 TWh in any given year.[57] Among the many more specific concerns about the Agreement raised before the UARB, two were fundamental: first, that Nalcor's cumulative obligation to supply market energy could be exhausted in as few as 16 year and second, that the agreement gave no assurance of the availability of market energy in the last 11 years of the 35 years of the project. On the first concern, the UARB accepted the testimony of experts called by its counsel who emphasized that the Agreement essentially gave NSPI a right-of-first-refusal on additional market energy throughout the 24 years of the agreement by obligating Nalcor to bid into annual NSPI solicitations for market energy.[58] On the second concern, the Board simply reiterated the conclusion reached in its initial decision, that the availability of market energy could be assumed after the expiry of the Churchill Falls Agreement between Newfoundland and Labrador and Quebec in 2041.[59]

The UARB's review of the Maritime Link project was constrained by the timeline for the review imposed by legislation. In its initial decision on the project, the Board noted it had not been able to fully consider an alternative to the Maritime Link which NSPML had not analyzed, under which renewable energy requirements would be met by combining renewable energy from multiple sources.[60] It may therefore be an open question as to whether the Board's conclusion might have been different after a more fulsome review. Because of this and concerns raised about the terms of the EAA, it may be possible to question whether the terms on which the Maritime Link project was approved give enough protection to Nova Scotia ratepayers. It is however harder to question that the regulatory process provided them with significant additional protection they would not otherwise have had. It also provided them with transparency and accountability on the justification for the project, its expected benefits and costs.

On a different scale, the same applies to the UARB's 2009 and 2010 decisions on the co-generation biomass project at the Port Hawkesbury pulp and paper mill, then owned by New Page and now owned by Pacific West Commercial Corporation. The project called for installation of a steam generator and condenser at the mill so that the wood-fibre-burning boiler already at the mill could be used to produce renewable electricity for NSP while continuing to provide steam for the mill.[61] It clearly and obviously had as much to do with the viability of the mill, which would soon be in receivership, as it did with NSPI's need for additional sources of renewable electricity. This perhaps explains why it first came to the UARB in 2009 as an application by NSP for pre-approval of the prudency of the proposed project – or rather, of the power purchase agreement that NSP would sign with the company created to operate the project – as well as a waiver of requirements dealing with competitive solicitation of purchased power set out in NSP's Fuel Manual.

The UARB ruled it had no jurisdiction to pre-approve the prudency of the power purchase agreement, for the same reason it had ruled in earlier decisions it had no jurisdiction to determine the price and conditions offered by NSP in soliciting bids from independent wind power producers: its jurisdiction was over the rates and charges which NSPI proposed to charge customers, not the prices which NSPI paid to its suppliers.[62] The Board used emphatic language to make the point that a clear line had to be maintained between utility management and regulation. Thus, contrary to what was suggested in evidence by NSP, it was not the role of the UARB to "partner" with NSP. Instead, it had to ensure its ability to independently and rigorously review the prudency of NSP's management of its business in the context of an application for approval of rates and charges was not compromised by its own prior involvement in the very managerial decisions that had to be scrutinized to determine if proposed rates and charges were just and reasonable. It was stressed further that the alternative approach would transfer the risk of ensuring the prudency of business decisions – a significant portion of the justification for NSP's allowable rate of return - from shareholders to customers. It would also reduce the incentive which the regulatory process imposed on NSP to ensure it managed to the prudency standard.

In short order, the project came back to the UARB under a different ownership structure as an application for approval of a capital work order, something clearly within the Board's mandate.[63] After purchasing the mill's boiler and related assets and purchasing and paying the mill to install the necessary generator, NSP would own the proposed "utility plant" and all of its produced electricity and pay the pulp mill for fuel and management services on a continuing basis.

The UARB was blunt in disapproving NSP's "unusual aversion to shareholder risk" in restructuring the project so that it required UARB approval.[64] It expressed frustration with the lack of justification provided by NSP for some aspects of the project, such as the soundness of the 30 year old assets that NSP was purchasing for a 40 year project.[65] It nevertheless approved the project. It did so because it accepted the view of NSP that a biomass project would add predictable renewable energy to the considerable intermittent wind power that NSP was building or purchasing to meet the "transformation in energy mix" required by the government policy of having 25 percent of electricity generated from renewable sources by 2015.[66] The outstanding issue was the $80 million up-front payment (on a $208.6 million project) to a "financially troubled partner for assets for which the Board has received no valuation". To address this concern, the board stipulated that the project was to be built for the overall cost indicated in the application and that any additional cost caused by the failure of the mill due to its financial situation was to be for NSP's account, not that of ratepayers.[67] In addition, the board stipulated that capital cost overruns would not be handled as "normal and routine requests for authority to over spend" but would have to be "applied for, debated and ruled upon in a public hearing process".

Load Retention Tariff Decisions

The broader context for the Board's consideration of the Port Hawkesbury biomass project are the multiple occasions on which it has been called on to address the impact of electricity costs on Nova Scotia's troubled pulp and paper industry. Several of these decisions intersect with the Board's decisions on DSM and renewable energy and provide further illustration of the balance the Board has struck between "traditional ratemaking" and the economic, social and political realities that must be accommodated within regulation.

The UARB's "pulp and paper" decisions include the approval in 2000 of a Load Retention Tariff (LRT) for the Port Hawkesbury mill and the Liverpool mill owned by Bowater on the basis of the options each had to sole-source its electricity.[68] In 2011, when the Port Hawkesbury mill was under protection from creditors and the Liverpool mill was facing imminent closure, the Board approved

57 *Re NSP Maritime Link Incorporated*, 2013 NSUARB 242 (CanLII), at paras 13-17.
58 *Ibid*at paras 19-24; 31.
59 *Ibid* at para 33.
60 *Re NSP Maritime Link Incorporated*, 2013 NSUARB 154 (CanLII), at paras 147-52.
61 *Re Nova Scotia Power Incorporated*, 2009 NSUARB 111 (CanLII), at paras 1-12.
62 *Ibid* at paras 28-47. The earlier decisions are *Re Nova Scotia Power Incorporated*, 2004 NSUARB 118 and *Re Nova scotia Power Incorporated*, 2005 NSUARB 98.

63 *Re Nova Scotia Power Incorporated*, 2010 NSUARB 196 (CanLII).
64 *Ibid* at paras 86-93.
65 *Ibid* at paras 62-65; 81-82.
66 *Ibid* at paras 108-12.
67 *Ibid* at para 162.
68 *Re Nova Scotia Power Inc.*, 2000 NSUARB 72 (CanLII). In addition, in 2003, it approved a non-cost-based rate for the two mills, initially called the Extra Large Industrial Interruptible Rate and subsequently called the Extra Large Industrial Two-Part Real Time Pricing rate.
69 *Re Nova Scotia Power Incorporated*, 2011 NSUARB 184 (CanLII).

amendments to the LRT.[69] One was to make it applicable in situations of "economic distress". Another was to fix the LRT for three years at rates designed to help the mills survive while maintaining fairness for other ratepayers. The Board concluded it was "reluctantly prepared to depart from traditional ratemaking … and provide an opportunity for [the mills] to stay on the system and make, on the Board's best judgment, a contribution to the fixed costs of the system".[70] The three-year LRT rate approved was a Board designed alternative to the five-year rate proposed by the mills which the Board concluded transferred unacceptable fuel costs risk to other ratepayers. The Board opted for this course instead of rejecting the application because rejection "would not contribute to meeting the financial challenge that the two mills face" or "provide other customers at least some opportunity to receive a contribution" to system costs "from the continued operation of the two mills".[71]

The same responsiveness to the difficulties of the province's pulp industry was displayed in 2012 when the Board approved a LRT rate specifically for the Port Hawkesbury mill.[72] By then the Liverpool mill had closed and the Port Hawkesbury mill was in the process of being purchased under a restructuring plan calling for significant reduction in labour, tax and electricity costs. The LRT was presented as necessary for the completion of the purchase and reopening of the mill. It proposed a rate based, like the one approved in 2011, on NSP's incremental cost of supplying the mill but that, unlike the 2011 rate, did not include the costs of DSM or of meeting Renewable Energy Standards.[73] The proposed rate would be fixed, subject to a five-year reopener, for more than seven years and include a lower "adder" for fixed costs than the one included in the three-year rate approved in 2011.

The UARB approved the new LRT on the usual basis: ratepayers were better off with the mill on the system contributing to fixed costs than they would be otherwise. Several specific considerations were critical to the decision. The pricing mechanism, unlike the rate proposed in 2011, included actual fuel costs on a week to week basis.[74] The Province made two key commitments on the record: first, that ratepayers would not be required to pay incremental costs of any additional RES obligation triggered by operation of the mill and second, that the Province would adopt regulations making the biomass plant a "must run" facility to prevent its operation for the mill when it was not needed for the system being counted as incremental cost to the system.[75] The broader consideration was simply the Board's acceptance of the submission, backed by financial information filed in confidence, that the mill would not be purchased and reopened without the proposed LRT.[76]

Observations and Reflections

Although it is not possible to definitely evaluate the impact of the UARB on the transformation of Nova Scotia's electricity system solely by reading its decisions, a number of specific conclusions can be offered. First, in ordering an IRP in 2007, the Board was a catalyst for the rapid development of DSM and renewable energy. Second, the Board has developed a regulatory framework for DSM that ensures it delivers the energy savings that provide its core rationale. Third, the Board has contributed to the development of a workable framework for the development of renewable energy and applied rigorous scrutiny to the major renewable energy projects that have come before it, including the transformational Maritime Link project. Fourth, the Board has managed the difficult task of protecting ratepayers and the core principles of economic regulation while being sensitive and responsive to the challenges that the cost of energy poses in

70 *Ibid* at para 213.
71 *Ibid* at para 204.
72 *Re Pacific West Commercial Corporation*, 2012 NSUARB126 (CanLII).
73 It also proposed a "Pricing and Dividend Calculation Mechanism" under which, for tax reasons, NSP would unusually be paid for the electricity it supplied to the mill largely through the dividends it would receive as a partner in the partnership formed to operate the mill. The Board concluded that such a payment mechanism was within its jurisdiction to approve "charges" for electricity. This aspect of the LRT proposal was subsequently dropped when the prospective purchase failed to obtain a favourable Advance Tax Ruling from the Canada Revenue Agency.
74 *Ibid* at para 152.
75 *Ibid* at paras 172-79.
76 *Ibid* at paras 67, 76-86.

a small, electrically-isolated province with a soft economy where electricity is largely produced by burning expensive coal and where significant investments have to be made in renewable energy and DSM if the dependency on coal is to be reduced in the future.

More tentatively and broadly, it can also be said that the UARB has helped to keep the process of electricity system transformation under way and on track. It has done this by subjecting the process, particularly its economic aspects, to effective and accountable regulation that is sensibly conducted.

Importance of the Legislative Framework

It of course matters to the role that the UARB has played in electricity system transformation that successive Nova Scotia governments have put their central policy choices into legislation. This has given the Board the statutory mandate to require the management and development of the electricity system in compliance with those policy objectives.

It has probably also mattered that successive governments have largely resisted the temptation to prescribe the specific plans and measures to be taken to achieve the legislated goals and objectives.[77] This has allowed the UARB, on behalf of ratepayers, to hold NSP (and ENSC on DSM) accountable for the development and implementation of those plans and measures. It has also meant that the plans and measures have been vetted and tested in a process that has been rigorous, open, transparent and accountable. In addition, a non-prescriptive legislative framework has also left the UARB with flexibility to keep the regulatory system responsive to changing conditions and evolving stakeholder expectations, as well as to the particular accommodations "traditional ratemaking" has had to make with Nova Scotia realities.

At the same time, Nova Scotia's legislative framework has been prescriptive enough to ensure that the complex and contested choices that the Province had to face to even begin the process of transforming its electricity system have for the most part been faced. They have not been deferred, as they might have been in a governance process more internalized to government, as "inconvenient truths". Here, the independence of the UARB and its accountability to deal with the matters that have to be addressed if the system is to be transformed in accordance with law in a manner that is cost-effective for ratepayers and otherwise in the public interest, has been of critical importance. In some cases, it has helped to ensure that attention is brought to matters on which further decisions have been required from government. In this way, the legislative framework has facilitated an iterative dynamic between the policy and regulatory processes.

Critically, UARB outcomes have enjoyed enough support to be a dependable basis for decisions and actions of a scale that are called for by the multi-year transformation that has been legislatively mandated. It has probably mattered in this regard that successive governments have not only respected the formal institutional independence of the UARB but also largely resisted the temptation to tilt the UARB's mandate in favour of proposals or plans that government may favour. Government has also largely left the process of the Board to be decided by the Board. Government has largely contributed to the regulatory process by appearing before the UARB to express its views on substantive and procedural matters on the record.

The exception to this "hands off" approach was a significant one: the legislation passed in 2013 to focus the scope and to limit the duration of the Board's review of the Maritime Link project. This was however, by any measure, an exceptional project. The choice of the government to have it reviewed by the UARB was at least as significant as its choice to limit the scope of that review. Moreover, the legislation adopted left the Board with a meaningful jurisdiction to conduct an independent and rigorous review of a project that was the subject of politically important intergovernmental agreements and foundational policy on energy, the economy and the environment.

Multiple factors, not all of them laudatory, may explain why Nova Scotia governments have not elaborated on the jurisdiction of the UARB to more explicitly align it with the electricity policy outcomes that the same governments have put into legislation. Nor is it clear that

77 See George Vegh, Energy Planning: The Case for a Less Prescriptive Approach (McCarthy Tétrault LLP, 2013).

the UARB has, in all respects, benefited from the "hands off" approach that government has taken. Reading the decisions of the Board, one can easily suspect that on a range of matters, the Board may have wished for clearer legislative direction of the kind that is enjoyed by counterparts in other jurisdictions.[78] At the same time, it is possible that the perceived independence, objectivity and fairness of the UARB process -and thus of its decisions - have benefited from the fact the Board works largely within an economic regulator mandate.[79]

Importance of the UARB's Performance

Important as the legislative framework has been in creating the conditions for the UARB to play the role it has, how the UARB has carried out that role matters at least as much. Indeed, the UARB's performance may have as much to do with its non-prescriptive legislative mandate as its legislative mandate has to do with its performance. Four elements of the UARB's approach warrant emphasis.

The first is simply the quality of the UARB's decisions as regulatory products. Each decision contains detailed and rigorous consideration of the arguments and the evidence presented on all of the substantive issues raised in the associated hearing. Consistently, conclusions are based on analysis that is thorough, detailed and comprehensive. Each hearing, circumstances allowing, provides ample opportunity to all participants to present their case and examine that of others. Each hearing is the culminating event in a process of information sharing that enables all parties to participate at the hearing on an informed basis. From an administrative law perspective, the reasons the UARB gives for its decisions do what the law says reasons for decision are supposed to do:[80] they clearly show the basis on which the Board has reached its decision; they show that the Board has carefully considered all of the issues and made informed choices on each of them; they provide clear direction or guidance as to what is to be done to implement or follow up on the Board's decision; and they clearly state the regulatory jurisprudence that the Board has relied upon and is therefore likely to rely on in the future.

Second, the Board has taken a clear but nuanced approach on the line between policy and regulation. On the one hand, it has taken its role as an agent of government policy very seriously, while at the same time being insistent that government express its policy in legislation. One aspect of this is the carefulness with which the Board has addressed questions about its jurisdiction, both in cases where it has concluded that it lacked it and in cases in which it has concluded that it had it.

On the other hand, the UARB has been sensitive to the broader policy context that surrounds the issues that come before it, whether that context is the exposure of ratepayers to rate shock, the importance of pulp mills in the economy of rural communities, the broader benefits of the Maritime Link project in integrating Nova Scotia into the North American grid, the importance of public awareness of energy efficiency to the success of those programs or the economic development rationale for development of tidal power. Such considerations may be outside of the Board's formal jurisdiction but they have informed what the Board has done within its jurisdiction. In addition, these broader policy considerations have been referenced and explained in UARB decisions, allowing those decisions to play a didactic function in explaining the context, importance and implications of policy and regulatory choices.

Third, on a related note, the Board has been careful to stay on the right side of the line between regulation and management. This is clearest in its first decision on the Port Hawkesbury biomass project but it is also reflected in the response of the Board to a range of proposals that are often made for the attachment of conditions to approvals and in the Board's willingness to shift the regulation of DSM in a less prescriptive direction. As the

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78 See Rowland Harrison, "Tribunal Independence: In Quest of a New Model" (2014) 2 *Energy Regulation Quarterly* 183.

79 Nova Scotia is currently considering a shift from cost-of-service regulation to performance-based ratemaking. See Nova Scotia Department of energy, *Regulating Electric Utilities – Discussion Paper* (2014), online: <http://energy.novascotia.ca/sites/default/files/files/Summary_Report_Regulating_Electric_Utilities.pdf>, and London Economics, *Literature review: regulatory economics and performance-based ratemaking* (2014), online: <http://energy.novascotia.ca/sites/default/files/files/Literature%20Review%20-%20LEI%20Consolidated.pdf>.

80 *Baker v Canada (Minister of Citizenship and Immigration),* [1999] 2 SCR 817.

Board explained in the first biomass project decision, it is very aware that its ability to regulate depends on a separation between its role as regulator and the role of the management of regulated entities in making the decisions or developing the plans the Board must review. It understands, in other words, that a regulator who enjoys trust and confidence must be independent from those it regulates as well as the government.

Fourth, the UARB believes in and practices process which is not only fair but inclusive and collaborative. It has made it clear that it expects those it regulates to work with their stakeholders, or rather with the representatives of their stakeholders who typically intervene in hearings. While making it clear that it will not subjugate its role to protect the public interest to negotiated settlements, the Board has also made it clear that a generally supported settlement based on defensible resolution of issues is an important indicator of where the public interest lies.[81] More generally, the Board has clearly manifested the expectation that meaningful consultation with stakeholders should normally be built into the applications that come before it for resolution by way of a hearing. In addition, the Board has instituted several standing consultation processes, such as a Fuel Adjustment Mechanism and the DSM Working Group.

In all of these respects, the UARB has made the highly technical process of economic regulation relatively inclusive. It has provided those with "skin in the game" who might otherwise go to government considerable incentive to participate in the regulatory process. At the same time, the insistence of the UARB on engagement has given government a highly defensible rational for leaving regulatory matters to the regulatory process. It also seems likely that the Board's commitment to stakeholder engagement has strengthened the functionality of the regulatory process by giving it a significant element of the tri-partism that is associated with "responsive regulation" and more broadly with modern approaches to regulation in multiple sectors.[82] ■

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81 For example, see Re Nova Scotia Power Incorporated, 2008 NSUARB 140 (CanLII), in which a settlement on a general rate increase was accepted. See also *Re Renewable Energy Community Based Feed-In Tariffs*, 2011 NSUARB 100 (CanLII); *Re Tidal Energy Feed-In Tariffs*, 2013 NSUARB214 (CanLII).

82 Ian Ayres and John Braithwaite, *Responsive Regulation: Transcending the Deregulation Debate* (New York and Oxford: Oxford University Press, 1992); Neil Gunningham, Peter Grabosky (with Darren Sinclair), *Smart Regulation: Designing Environmental Policy* (Oxford: Clarendon Press, 1998).

CHANGING ENERGY SYSTEMS: IMPLICATIONS FOR REGULATORS AND POLICY MAKERS

*Michael Cleland**

Introduction and Overview

Energy delivery systems are changing – fundamentally and possibly very quickly – because of the combined effects of several factors: technology, environmental demands and growing concerns about system performance on costs, reliability and resilience.

The systems may be changing but the customers aren't and there is peril in looking too closely at other industries such as telecoms for clues to the way the future might unfold. Energy is boring and that is how customers like it.

For public policy makers it isn't boring at all. Public policy has a big stake in the speed and nature of the coming transformation. While local energy sources (including efficiency measures) will grow in importance it seems unlikely that individual consumers will become autonomous or that energy will be delivered through the ether without benefit of wires or pipes. In other words, the wires, the pipes, the monopoly businesses that own them and the regulators that oversee it all will be with us for some time.

For both policy makers and regulators this is far from business as usual. If there is a compelling argument for a more strategic conversation about the upstream energy system there is an even more compelling argument for that sort of conversation downstream – and it needs to engage policy makers, regulators, everyone in the energy service delivery value chain and customers.

A Bit of History

About seven years ago the Canadian Gas Association (CGA) and Pollution Probe agreed to collaborate on an entirely immodest effort to change energy thinking in Canada. The goal was to shift the conversation from being singularly focused on upstream oil and central power to include the downstream system – the customer and the retail delivery system. The initiative acquired the moniker "QUEST" or Quality Urban Energy Systems of Tomorrow.[1] At that time - in 2007 –more attention to the downstream was an idea based on common sense, a small base of experience, and understanding of emerging technologies but it was far from mainstream in fact or perception.

Why common sense? Simply put, because in the search for better environmental performance, the lack of attention to the downstream meant that we were leaving half of the potential on the table.(The following points are all common knowledge and easily verified by reference to public sources such as the International Energy Agency, the U.S. Energy information Administration or Natural Resources Canada.)

- Much of the decline in carbon intensity in the U.S. and Canada that we had

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1 Quality Urban Energy Systems of Tomorrow, online: QUEST <www.questcanada.org>.

been seeing for some time was driven by efficiency not by reduced carbon in fuel supplies.

- It was easily demonstrated that efficiency gets gains at very low or negative cost - unlike decarbonisation of the energy system - and cost is always a primary consideration no matter how much one worries about carbon and climate.
- End use efficiency can have a big multiplier effect upstream due to system losses.
- By thinking about full system efficiency – essentially heat management – ways could be found to use more of the energy that is otherwise rejected - fully half of the total energy that comes into the Canadian energy system.
- To round it out, many local sources looked increasingly promising if not quite economic – waste as an energy source, local renewables such as solar, biomass, geothermal, deep water cooling, and on it went.

A few years on what we knew in 2007 is just as true today and several other factors have intervened to make the case still more compelling.

- The potential cost of replacing, upgrading and "smartening" our traditional energy infrastructure is growing ever more daunting and we have much slower population and economic growth with which to soak up the associated costs.
- Cost aside, no-one wants to see anything built in their vicinity and "not in my back yard" often extends hundreds of linear kilometers.
- Renewable energy especially bio-fuels and distant electric power bring their own challenges: cost, land intensity, environmental effects, and infrastructure requirements. And, just like everything else, they need to be built in someone's back yard.

We have also come some way back toward a more clear-headed view of the policy interest in energy. We have long understood the importance of diversity in support of security, reliability and resiliency. But that home truth had been swamped in the great carbon panic leading up to Copenhagen in 2009.

The term "carbon panic" is used advisedly. Let us start by acknowledging that significant reductions in carbon from energy production and use is essential insurance and that it can be cost-effective even in the short term if done in a way that brings other dividends – such as efficiency or other environmental benefits. But by late in the last decade climate action had acquired a sort of frenzied urgency and proposals were being advanced that failed the most rudimentary test of energy literacy: an understanding that safety, reliability, cost, and multiple environmental effects all matter and that failing to account for them was a certain recipe for loss of public support.

Most recently two other big factors have become much more prominent.

Public attention is increasingly turned to environmental risks - hurricanes, ice storms, floods – all of which raise questions about resiliency. This is hardly new but it has become much more salient.

And technology may finally be evolving to potentially "disruptive"effect, not through any one silver bullet but by the convergence of several technological streams:

- Unconventional gas development has transformed both the availability and price of natural gas supplies.
- The declining cost of solar electricity and the growing potential of distributed storage in combination with small scale (mainly gas fired) combined heat and power systems have radically increased the potential of distributed power.
- Advances in battery systems may bring battery electric vehicles more into the mainstream.
- The massive and pervasive effects of information technology have made more complex, multi-directional, multi-source integrated systems practical.

In short it increasingly feels as if we are on the cusp of a true energy transformation – possibly the first in over a century. Let's think about what that could mean.

A Look to the Future

It does mean one way or another that the world of energy utilities will change fast and potentially radically. However, before we mourn or celebrate the death of the electric utility as some commentators have been doing of late it is first useful to reflect on just how wrong our energy predictions can be.

Recall the pressures on gas utilities dating back a decade or more – the pressures that induced CGA to take the initiative to create QUEST.

By 2007 gas utilities were facing several challenges:

- Concerns were growing about cost and availability.
- Per customer volumes were steadily declining due to efficiency and competing fuels and supply technologies.
- Extending gas systems to grow the customer base was expensive, especially into low density developments without large anchor loads.
- Many of the big thinkers in energy were entirely focused on carbon; so called distributed combustion had to go and the world had to be transformed to one that was essentially all electric.
- Some of the gloomier prognosticators mused about the coming death of the gas distribution utility.

It is useful to keep the above in mind as well as what has happened since as we contemplate a different set of circumstances which in the minds of some herald the end of the electric utility.

At the very least the energy delivery world is assuming a different form, much of it along the lines of the QUEST vision – more distributed in the case of electric power and vehicle fueling, less distributed in the case of heat. The big question is: whither grids?

Ironically one leading light in the U.S. industry has been reported envisaging a world where the electric grid might be eliminated with power coming from solar combined with fuel for micro-CHP systems supplied by the gas grid. So now it turns out that the gas grid is the one that won't go away. So much for predictions.

And of course the other grid that has come increasingly into serious market contention is the thermal grid. Thermal grids have various advantages - the potential to use bio-mass as a primary fuel or to be multi-fueled; scale economies that allow them to be complemented by geo-thermal sources, rooftop solar or waste heat capture; and a natural pairing with the power system through CHP systems. Thermal grids will likely become more commonplace.

As to the electric grid, entirely autonomous buildings seem to be a very unlikely prospect. Even if they are potentially feasible, it seems likely – in urban areas at least – that the cost of local power generation and storage sufficient to meet all electric loads including peak would be greater than the cost of maintaining grid connection, even paying a reasonable – and fair - share of the costs of that grid.

Micro grids are already emerging and it seems more than likely that they will grow in building complexes with diverse thermal and electric loads such as campuses, hospitals, shopping centers or office complexes. The case for micro-grids as a contribution to a distributed power system and as a measure to enhance resilience seems to have become well established, especially after recent environmental events such as Hurricane Sandy. Micro-grids will most likely be connected to the larger grid due to economic opportunities to sell any surplus power, because they are potential system resources in terms of reliability and restart and because the economics of balancing thermal and electric loads tends to benefit from the scale economies of large interconnection areas.

Even if the potential exists to do away with those nasty utilities it is not obvious that it will happen very soon, especially not for small scale commercial and residential customers. In some recent articles in the industry press, advocates of distributed power have extolled the virtues of consumer choice and autonomy along with the enhanced value proposition entailed in being greener. Greenness aside, the model here is of course telecoms.

But let's take a step back and ask whether the analogy to telecoms is really apt.

First, the potential new value proposition is more limited – for the consumer the end result is essentially the same things: lights and a warm house (although distributed vehicle fueling is something else). It is hard to see how a transformed energy system makes calls to grandmother or posting selfies on your Facebook page any easier or cheaper.

Second, for all the liberation implied in the telecoms model, it seems doubtful that there has been a great increase in warmth of feeling toward service providers. Customers have a choice but they still have the service providers' systems in their houses. When the irritation level gets too high they can switch but the transaction costs entailed in doing so are substantial.

Third, based on years of experience with energy consumers, most observers have seen little evidence of interest in choice. Retail deregulation in gas and electricity has not generated the predicted change. Gas customers have tended to either stick with the incumbent utility or in some cases migrate back to it after a brief dalliance with a third party energy provider. Environmental attributes matter of course but experience shows that a very small share of customers are willing to pay more for green attributes. What is clear is that most of all, customers just want peace of mind (a system that always works); that has low intrusiveness (they don't have to think about it); and low cost.

And yes the younger generation are more environmentally aware but they will all grow older and acquire the attributes of householders with multiple responsibilities and constrained budgets. It seems imprudent to factor changes in basic human nature into any prediction of transformational change in energy systems.

In short, if one were trying to predict the future of energy the best bet would be on customers continuing to look to safety, reliability, out of sight out of mind, and low cost. When they act politically of course, citizens will demand environmental attributes but that takes us out of the realm of the private transaction and into that of public policy.

The Challenge for Public Policy

It is possible that we may someday leave the era of energy grids but not soon. In fact we may well be going the other way – with three grids increasingly the norm – power, gas and thermal along with a vehicle fueling system depending increasingly on the electric and the gas grids. Most important they will all be interconnected with one affording resources to the other.

And that is where the need arises for a more strategic conversation about both the policy and regulatory implications of that sort of change.

First, this article has argued that there are several potential policy benefits to be found in the world of multiple interconnected grids based on diverse (both centralized and decentralized) resources. Governments, in short should increasingly see it as in the public interest to encourage the sort of change implied in all of this – provided that it is cost-effective over a plausible time horizon (no rate shock), that it lives up to its promise in terms of reliability and resiliency and that it delivers environmental benefits.

Governments should look first to what competitive markets can deliver and if a big priority is to deliver less carbon then they should price it. But with or without carbon pricing it is not clear that competitive markets alone will deliver the best outcome for public policy.

First of all consumers have notoriously short time horizons for payback. Information acquisition and transaction costs can easily swamp any putative value proposition. Markets, in other words, don't always work.

Second, more rapid investment in technology is required – especially in the application of technology in integrated systems – each of which will pose its own technical and management challenges. Some of that investment is arguably a public good since a substantial part of the benefit cannot easily be internalized by investors – especially in utility systems themselves.

Almost any investment in this sort of system will have a long time horizon. Individual consumers – even larger commercial or industrial consumers - will not invest where paybacks are much more than a (very) few years and they will not take on management complexities that distract them from their

core business. Finally, competitive investors in supply technologies faced with investment returns that are uncertain as well as long in coming may choose to invest elsewhere.

And if it all remains tied to grids then we still have natural monopolies that entail complex management challenges. Gas and electric grids will still be regulated. Thermal utilities will largely become regulated – even if light-handedly - because of the inherent market power in the hands of the provider once the customer is signed up. And the systems will become more and more untidy compared to the unbundled world of standalone wires and pipes that has been the governing paradigm for over twenty years.

A thermal system is not just pipes but also the thermal resources that supply the pipes. If it involves combined heat and power assets then it becomes part of the system of electric power resources. A power system dependent on radically distributed resources such as CHP, solar and storage might work with all of those resources supplied from independent entities. Or it might require much tighter integration than is afforded by an entirely unbundled model. Fueling systems requiring high upfront investment and facing slow market growth might or might not get built at all. A vehicle stock which becomes part of the electric storage system brings its own management challenges. Other behind-the-meter investments including garden variety energy efficiency investments are unlikely – as in the past - to be made at a level consistent with public policy objectives or be as effective in terms of power system balancing without integration one way or another into the management of the larger energy delivery system.

How does all of this play out in the regulatory world?

We have seen and will see more tension between competitive suppliers and regulated utilities. Even utility affiliates are suspect because of perceptions that they will have an unfair advantage due to their affiliate relationships. On the other hand, competitive players have not exactly rushed into the game in the face of a weak consumer (private) value proposition and very long paybacks. Whether that will change in the face of technology change and declining costs remains to be seen.

Utilities themselves are of course inherently conservative although many have seen the writing on the wall – as did gas utilities in their support for QUEST. The utilities that do see the writing on the wall will look to reshape the business model by expanding their service offerings and they will fiercely protect their ability to maintain the integrity of their systems. They might or might not be positive change agents but, regardless, it seems unlikely that they will look fondly on the prospect of so-called death spirals and nor should policy makers or regulators.

The instinct of regulators seems to be to ensure that utilities not venture into activities beyond the pipes and wires. The unbundled model has served us well for two decades and allowing that to erode reintroduces a world of non-transparent cost allocation and possible barriers to the emergence of competitive suppliers. On the other hand the New York State Department of Public Service in a recent staff paper signalled that they see no inherent reason why electric utilities cannot invest in power resources alongside competitive players.

The instinct of policy makers ranges from "ignore it" to "just do it". Almost none understand the regulatory system which for most is something of a mystery and, just like consumers, most of the time they prefer the whole thing to remain out of sight out of mind. When they do want change, policy makers see the regulatory system as slow and conservative which of course it is. Better to use directives or familiar tools such as mandates and subsidies regardless of whether they match well with regulated systems.

This combination of forces looks on balance as if it will inhibit innovation or at least make it even more disruptive (in a negative sense) than it need be.

I'm your local utility regulator and I'm here to help you innovate

This is not a line from a lame joke although it could be. It is possible that the future of energy delivery may be just as regulated as in the past – maybe even more but based on different models despite the risks to clarity and transparent cost allocation and the potential to inhibit competitive players.

The regulatory system may have its limitations but it also has attributes in a combination that neither competitive markets nor other policy instruments can replicate.

- If we still live in a world of grids, the regulatory system will oversee the underlying networks on which innovative supply and demand technologies will have to be built.
- The regulatory system supports a business model with long time horizons – a characteristic of most energy systems.
- The regulatory system can explicitly build external (public interest) costs into the system through things like system benefits charges or demand side management expenditures.
- It allocates costs to customers with strict attention to fairness; other policy approaches allocate costs to taxpayers – and fairness is optional.
- It is close to customers with a deep understanding of habits and needs and the capacity to deliver most of the attributes that customers look for.
- Regulatory processes are distinct from policy processes in important and desirable ways: expert, evidence based, transparent and subject to due process.

A Bigger Conversation

The clearest path toward more sustainable, less carbon intensive energy systems involves real prices for energy including a carbon price. But most governments are not yet prepared to price carbon especially at the small consumer level because consumers are not ready for it.

In the meantime, other forces including other policy measures have contributed to new solutions being developed and applied. It is arguably in the long term interests of society – and of customers - to experiment and to bring more of those solutions into play, some of which will come up short, others of which will be winners.

Where competitive markets work we should leave it to competitive markets. Where competitive markets don't deliver and where innovative solutions stand on the platform of the regulated system there is a case to be made for regulatory systems to take an active role and experiment. Apart from anything else, one thing we know is that consumers will never be ready for carbon pricing unless there are lower carbon solutions ready to hand.

If that is to happen we need a different sort of discussion. The regulatory community – regulators, utilities, customers and competitive service providers - needs to stand back from day to day preoccupations and from the adversarial environment of the hearing room. Some years ago regulators and utilities in Canada initiated a series of regulator/industry dialogues. They were a good idea which helped advance mutual understanding. But they were limited in their goals and they did not attract policy makers or reach a broader audience.

In future discussions policy makers need to be active participants because much of what needs doing will require policy or legislative support. And to be seen as legitimate, such discussions need to be accessible to a broader range of participants and a broader audience.

The subject matter is vast in its scope and paralyzing in its complexity but it is also about the fundamental configuration of our energy systems for decades into the future. We are stumbling into the future right now whether anyone wants it or not. We will make mistakes; some ideas will come up short and there will no doubt be many black eyes.

If we could just acknowledge that last point it might be liberating. Better black eyes than black outs. ■

CONSERVATION COMBINED HEAT AND POWER IN ONTARIO: POLICY SOLUTION OR REGULATORY CHALLENGE?

*Richard Laszlo**

Advances in CHP[1] technology, coupled with a widening "spark spread"[2], have reduced capital costs and improved the operational competitiveness of CHP systems. This has increased interest among facilities with a consistent need for both heat and electricity as well as those that place a high value on energy security and reliability. Improved economics, coupled with the availability of pre-packaged, modular systems, have opened up opportunities for relatively small-scale private investment and ownership in CHP.

This article provides a brief summary of Ontario's CHP policy and regulatory framework, and comments on the implications of increased load displacement CHP projects on utility-customer relationships, roles and responsibilities, and on implications for regulators.

Policy and Regulatory Snapshot

From an energy *policy* perspective, CHP offers a clear and compelling value proposition:

> *Assuming that the heat is well-used, CHP can achieve the highest use of the energy available from a fuel, making it the most efficient way to use fossil fuels while generating electricity. CHP can achieve up to 80% overall efficiency when it is designed to follow the heat load.*[3]

CHP combines this high efficiency with extremely reliable operation,[4] so much so that several jurisdictions are establishing guidance for utilities to facilitate implementation of CHP and other distributed generation projects as a reliability and resiliency response in the wake of extreme weather events such as Hurricane Sandy.[5] CHP is scalable and can be deployed relatively quickly, often without any public opposition, even when sited in dense urban areas.[6] Although most CHP systems do use natural gas, they can be designed to operate

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1 CHP stands for Combined Heat and Power, also referred to as cogeneration. These systems capture otherwise wasted heat during thermal electricity generation, making available both heat (via hot water or steam) and electricity available for use.

2 The price divergence between grid-supplied electricity and the cost of generation using natural gas, the typical fuel used in most CHP systems.

3 Ontario Ministry of Energy, *Ontario's Long Term Energy Plan* (2 December 2013), online: <http://www.energy.gov.on.ca/docs/LTEP_2013_English_WEB.pdf>.

4 U.S. Environmental Protection Agency (EPA), *Reliability Benefits,* online: <http://www.epa.gov/chp/basic/reliability.html>.

5 U.S. Department of Energy (DOE), U.S Department of Housing and Urban Development (HUD), U.S. Environmental Protection Agency (EPA), *Guide to Using Combined Heat and Power for Enhancing Reliability and Resiliency in Buildings* (September 2013), online: <http://epa.gov/chp/documents/chp_reliability.pdf>.

6 The relatively small scale of CHP systems allows them to be integrated into building design. For an inventory of Canadian CHP systems, see CIEEDAC's *Cogeneration Facilities in Canada* (March 2014),

using a variety of input fuels, such as biomass, and to meet a range of output heat and power requirements. And when compared against Ontario's fleet of large, central combined cycle gas turbines used for generation at the margin, a well–designed CHP system can reduce overall natural gas consumption and resulting greenhouse gases in the province.[7,8]

The *regulatory* picture is substantially more clouded. CHP complicates matters as it expands the number and diversity of customers interested in self-generation to include smaller industrial facilities, commercial and institutional buildings and even large residential developments, an ability once reserved just for large industrials. When CHP systems are designed as load displacement generation projects, they are potentially disruptive to the current electric utility business model, and also blurs the lines on customer and utility roles, relationships and expectations.

Further complicating matters, CHP is unique as a multi-fuel technology with the potential to cross the regulatory divide of electricity and natural gas.[9] For example, it is conceivable that a load displacement CHP project could be eligible as both conservation and demand management (CDM) for electricity as well as demand side management (DSM) for natural gas. CHP can simultaneously displace electric load from the distribution system as well as reduce natural gas use when compared to Ontario's fleet of combined cycle gas-fired plants that generate electricity at the margin in combination with customers' boilers. The Ministry of Energy called for CDM/DSM alignment in its Conservation First directive to the Ontario Energy Board,[10] and CHP is a perfect energy application for the promotion of joint electricity and natural gas utility collaboration since it straddles both heat and electricity.

Not just Procurement

There are three potential connection configurations for CHP connection to the electricity distribution system or the transmission system in the case of a large industrial plant:

i. **Where all power is exported from the facility to the distribution system, either through CHP operation as a merchant plant or via a power purchase agreement:** Some readers will be familiar with Ontario's recent history of CHP procurement efforts. In its recent Long Term Energy Plan (LTEP),[11] the Ministry of Energy included reference to a CHP program and subsequently issued a Ministerial Directive to the Ontario Power Authority (OPA)[12] to establish the second round of a Combined Heat and Power Standard Offer Program (CHPSOP 2.0) targeting greenhouses (100 MW) and district energy operators (50 MW).

ii. **"Behind the meter generation" whereby all of the power is consumed by the host facility as a load displacement generation project:** Ontario's energy policy treats load displacement-CHP as an electricity conservation measure, as it reduces a facility's requirements for power from the distribution system. As a conservation measure, these behind-the-meter CHP systems were eligible for conservation and demand management (CDM) incentive programs under the previous conservation framework (2011 – 2014), and the Ministry recently and rightly renewed its eligibility in the Minister's Conservation First Framework Directive to the OPA.[13]

online: <http://www2.cieedac.sfu.ca/media/publications/Cogeneration_Report_2014_Final.pdf>.

7 The LTEP cites an overall efficiency of up to 80 per cent for CHP, and the OPA cites its fleet of combined cycle gas turbine (CCGT) plants can achieve efficiencies of up to 55 per cent.

8 U.S. EPA, *Combined Heat and Power Partnership, Efficiency Benefits*, online: EPA <http://www.epa.gov/chp/basic/efficiency.html>.

9 Ontario Energy Board Act, 1998, ss 1, 3.

10 Ontario Energy Board, *Ministerial Directive to the Ontario Energy Board* (26 March 2014), online: OEB <http://www.ontarioenergyboard.ca/oeb/_Documents/Documents/Directive_to_the_OEB_20140326_CDM.pdf>.

11 Ontario Ministry of Energy, *Ontario's Long Term Energy Plan* (2 December 2013), online: <http://www.energy.gov.on.ca/docs/LTEP_2013_English_WEB.pdf>.

12 Ministerial Directive to the Ontario Power Authority (31 March 2014), online: <http://www.powerauthority.on.ca/sites/default/files/news/MC-2014-856.pdf>.

13 *Ibid*, The Minister's Directive of March 31, 2014 states that "The OPA shall consider CDM to be inclusive of activities aimed at reducing electricity consumption and reducing the draw from the electricity grid, such as geothermal

iii. **Net-metering, allowing for two-way flow of electricity between the facility and the distribution system:** While net-metering is theoretically permitted for CHP systems that combust biomass or biogas,[14] the Green Energy and Green Economy Act's Feed in Tariff provides a direct procurement mechanism for generation of electricity from bioenergy.[15] For natural gas fired CHP, net metering is not yet permitted.

Implications for Utilities

In its LTEP vision, the Ontario government has indicated that it sees net-metering as the future for small-scale renewable projects. In the absence of extending this vision to CHP systems using natural gas, it is behind the meter CHP, or so called "conservation combined heat and power" (CCHP) that provides the greatest potential for furthering Ontario's long-term energy policy objectives. Unfortunately for proponents of such projects, they are also disruptive to the electric utility business model.

Ontario's Conservation First Framework (2015-2020) has set ambitious conservation targets. The OPA is currently embarking on a process to effectively allocate $2.1B of budget funds and 7 terawatt hours (tWh) of CDM targets across all electricity LDCs. The 7 tWh represents about a 90 per cent increase over the 2011 - 2014 average annual energy savings.[16] To meet these targets, many LDCs are looking for opportunities to assist their customers beyond switching out old inefficient light bulbs and helping industry move to higher efficiency electric drive motors. Considering a relatively modest 500 kW CHP unit can reduce electricity consumption by approximately 4 GWh per year,[17] it's not surprising that LDCs are increasingly looking at CCHP project opportunities in their respective service territories.[18]

The challenge of course is that these projects impact the existing LDC revenues, especially among smaller LDCs where a couple of independent CCHP projects can account for a significant portion of their overall load. This could result in stranded generation or transmission assets, and in some cases may require added distribution and transmission system investments by the incumbent to protect against such issues as thermal and short circuit fault conditions. As a result of these lost revenue and cost impacts, many LDCs have responded by introducing, or in some cases reintroducing, stand-by charges, providing a disincentive to the establishment of CCHP systems, a move that stands in direct conflict with stated Conservation First objectives. While standby charges are warranted in that CHP proponents are using a service and rely on the grid should their system fail, their application is not consistently applied across Ontario's LDCs, and often do not account for any potential benefits accrued to the system, such as deferring transmission or generation investments.

Other LDCs have used their unregulated affiliates to invest in such CHP projects, however, under current conservation programs, third-party investment and ownership of CHP systems do not qualify for CDM incentives, whether pursued by LDC affiliates or the private sector. Compounding the risks and uncertainty for potential CCHP proponents is the concern that additional costs will be introduced over time, perhaps through a surcharge, such as Ontario's Global Adjustment Mechanism.

A Regulatory Solution?

Two regulatory processes point to possible solutions, albeit imperfect ones. These options

heating and cooling, solar heating and small scale (i.e., <10MW) behind-the-meter customer generation." (Section 7.1).

14 *Electricity Act*, 1998, SO 1998, c 15, Schedule A.

15 Ontario Power Authority, *Feed in Tariff eligibility requirements for bioenergy*, online: OPA <http://fit.powerauthority.on.ca/fit-program/eligibility-requirements/renewable-fuel/bioenergy>.

16 Ontario Power Authority, *Target and Budget Allocation Methodology, Conservation First Framework LDC Tool Kit* (23 September 2014), online: OPA < http://www.powerauthority.on.ca/sites/default/files/conservation/LDC-Target-Budget-Allocation-Methodology-Summary-Draft-v3.pdf>.

17 Assuming the system operates 8,000 hours per year (500 kW x 8,000 hours = 4 GWh/year).

18 QUEST co-chairs an Ontario CHP Working Group, where one of three objectives is LDC Engagement. Several LDCs are represented in the working group, including PowerStream, Veridian, Oshawa PUC, and London Hydro. These and many other LDCs are actively pursuing opportunities for load displacement CHP projects as a means to achieving their current and future CDM targets.

are not mutually exclusive, with many potential variations that could be applied depending on the circumstances.

The first option is provided by the Ontario Energy Board, which has released a discussion paper outlining options for a fixed rate design, also known as rate or revenue-decoupling.[19] This means that the LDCs can recoup their costs plus earn their regulated rate of return based on only fixed charges from their customers rather than today where that return is paid back via both fixed (kW) and variable (kWh) charges. The OEB's stated purpose is to support the policy direction outlined in the LTEP by removing any disincentive to increased distributed generation. While the OEB appears at this stage to be moving forward with residential and small business customers only, the scope is eventually expected to also include larger customers that would be looking to develop CCHP projects.

The second, more radical option is provided courtesy of New York State's *Reforming the Energy Vision* proceeding,[20] where the Public Service Commission is reviewing its regulation of electric utilities. In a joint filing, subsidiaries of electric utilities argued that utility ownership may be appropriate where integration of distributed generation could improve reliability, where it results in deferred investments in transmission and distribution infrastructure, and when it could benefit certain customers. Of course not everyone is in favour of allowing for even limited re-bundling and vertical integration of utilities, but CHP has the potential to satisfy the conditions put forward by the collection of New York utilities.

Most significantly, the common conclusion and driver linking Ontario's exploration of revenue decoupling for LDCs to New York's consideration of its regulation of distribution utilities is that distributed generation, including CHP, should play an increasing role in tomorrow's energy system.

The Ontario Energy Board has taken a courageous step in outlining the possible options for proceeding with revenue decoupling in support of the government's policy objectives. While providing for some limited "re-bundling" might be unpalatable to some, it would certainly be in the interests of Ontario ratepayers and utilities for the Board to follow the New York regulator's lead and at least examine the conditions under which some bundling might be considered. Ontario's regulators are tasked with ensuring the safe, reliable and cost-efficient delivery of electricity to customers. To carry out this task effectively within the rapidly changing technology and economic environment, regulators should be willing to entertain unconventional approaches. For example, they should be afforded the flexibility to handle a multi-utility CDM/DSM application in the case of load displacement CHP projects, and to consider submissions where utilities put forward a compelling case for grid management, even if that does mean investment in assets on the customer side of the meter.[21] The Ontario Energy Board has provided a guideline[22] that sets out the regulatory framework for distributor-owned generation facilities, including CHP along with renewable generation and storage, although utilities cannot include applicable generation assets in their rate base. This is an excellent first start in levelling the playing field for utilities to invest in behind the meter CHP, alongside their regulated affiliates and the private sector. Nonetheless, barriers and uncertainties remain, however. There are opportunities for the regulator to expand on the steps it has already taken by leveling the playing field across Ontario's utilities with respect to setting stand-by charges, by requiring that LDCs connect

19 Ontario Energy Board, *Rate Design for Electricity Distributors* EB-2012-0410 (31 March 2014).

20 New York Public Service Commission, *Reforming the Energy Vision: NYS Department of Public Service Staff Report and Proposal,* No 14-M-0101 (24 April 2014), online: NYS Department of Public Service, <http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/$FILE/ATTK0J3L.pdf/Reforming%20The%20Energy%20Vision%20(REV)%20REPORT%204.25.%2014.pdf>.

21 Peaksaver devices are a ubiquitous example of ratepayer-funded assets installed on the customer side of the meter.

22 Ontario Energy Board, *Regulatory and Accounting Treatments for Distributor-Owned Generation Facilities,* G-2009-0300 (15 september 2009), online: OEB <http://www.ontarioenergyboard.ca/oeb/_Documents/Regulatory/Guidelines_reg_accounting_treatments_G-2009-0300.pdf>.

behind the meter customers where reasonable, and by introducing more certainty with respect to future application of charges such as the Global Adjustment Mechanism.

Conclusion

CHP combines a highly efficient and reliable operation, along with a number of other highly desirable attributes that contribute to policy objectives, including resiliency, improved environmental performance, as well as cost control for industry. Most of the limited policy discussions and decisions regarding CHP are related to the latest procurement programs that target only specific sectors, and yet load displacement CHP not only offers a potential route for achieving the Ontario government's ambitious Conservation First targets, but also enables desirable options for energy consumers across the province, to manage their energy costs and add resiliency for their operations. The regulator holds one of the keys to unlock CHP's potential, and should continue to level the playing field and remove barriers to investment, both by the public and the private sector, in efficient and distributed energy infrastructure. ■

THE JOY OF DECISION WRITING

Mr. Justice David M. Brown[1]

Introduction: The Joy

Justification, transparency and intelligibility in the decision-making process, coupled with acceptable outcomes which are defensible in respect of the facts and the law, are the hallmarks of sound regulatory tribunal decisions according to the seminal decision of the Supreme Court of Canada in *Dunsmuir v. New Brunswick*.[2] It follows that when tribunal members come to write their decisions they must ensure that their reasons justify the result reached and disclose a transparent, intelligible line of reasoning which supports and explains the result.

In the inaugural edition of the *Energy Regulation Quarterly* Professor David Mullan gave the following wise advice to tribunal members:

> Where possible, base your decision on a careful examination of the facts, the intricacies of your own statutory regime, and the law developed by your own tribunal or agency precedents. The courts will generally respect your expertise and apply a deferential standard of review if you remain rooted in those issues.[3]

How does a tribunal member apply that advice in day-to-day practice? This short article seeks to offer tribunal members some practical direction about writing decisions, the part of the judicial job I most enjoy. I find decision-writing to be a joy, and through this article I hope to share some of my enthusiasm for that process. Of course, in the words of the old ABC Wide World of Sports intro, the thrill of completing a set of reasons can, in some cases, be followed by the agony of reversal by a reviewing court. Such is the life of front-line tribunals and courts which make the initial decisions. It is safe to say, however, that the harder a tribunal strives to meet the goals of justification, transparency and intelligibility, the less the chance its decisions will be reversed on review.

The Decision's Audience

Reasons are meant to tell the parties what the tribunal has done and why it did so. Reasons should offer assurance to the parties that their positions were understood and considered by the tribunal in arriving at its decision. As put by the Ontario Divisional Court in one case, "reasons are required; not merely conclusions".[4]

One of my former colleagues, Mr. Justice Dennis Lane, gave the following advice to tribunal members about identifying the audience for their reasons:

> There are many audiences for your, and our reasons: the courts, the parties, the public, the press, the legal academics, and so on. The audience many decision-makers think of first is the Court of Appeal or the [Judicial Review] court. But I will tell you: it is a mistake to write for the reviewing court. To do so gets in the way of writing for the most important reader of all: the party who is about to learn that the case has been lost. If you can explain to that person in clear language why the case was lost, you will have no worries that a reviewing court will not understand what you did and why you did it. In general terms, write for the educated layperson; that is usually the description of the parties, so

1 Superior Court of Justice Ontario. An earlier version of these remarks was given at the CAMPUT Energy Regulation Course at Queen's University in July, 2014.
2 *Dunsmuir v New Brunswick,* 2008 SCC 9 at para 47.
3 David J Mullan, "Regulators and The Courts: A Ten Year Perspective" (2013) 1, *Energy Regulation Quarterly*, 13 at 14.
4 *Clifford v Ontario (Attorney General)* (2008), 90 OR (3d) 742, (Div Ct).

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that is the same advice as writing for the losing party.[5]

Preparing to Write Your Reasons: Before and During The Hearing

The preparation for writing a decision starts before the hearing begins. The tribunal member must master the written record filed in advance of the hearing. Doing so enables the tribunal member to understand the issues in dispute and to ask questions at the hearing which clarify the issues and the evidence upon which the reasons must be based.

While most tribunals enjoy the availability of real-time transcripts of a day's proceeding, a tribunal member needs to make some notes during each hearing day. A member should record:

i. his views about the credibility and reliability of the evidence given by each witness;

ii. the plausibility of the various arguments advanced before the tribunal and his evolving views about those arguments as they are heard; and,

iii. those matters he wishes to raise with subsequent witnesses during the hearing.

At the end of each hearing day a member should take the time to prepare a short summary of his thinking about the issues based upon the evidence heard that day, in light of all the evidence heard up until that point of time. The last portion of the member's daily notes should contain a kind of diary of the member's evolving thoughts about the issues at play in the case and the possible outcomes on each issue. At the end of a typical trial day I usually spend up to 1.5 hours going over my notes, breaking them down into discrete issues for easy subsequent reference and putting down comments about witness credibility and my thinking on the issues.

Starting to Write the Actual Decision

Of course, the focus of a member's efforts each day should be on ensuring that he understands the evidence given and the arguments heard, and so prepare for the next day's evidence. But, at some point of time, a member has to start sketching out an outline of the decision, an outline which identifies the issues to be decided and the member's preliminary thoughts on each issue.

Ideally, the process of sketching an outline should begin before the tribunal starts to hear evidence. The pre-filed evidence enables the identification of the issues in dispute, as well as the parties' general positions on each issue. The originating document for the hearing, such as a notice of application, will specify the relief sought allowing the tribunal to know, in advance of the oral hearing, what it will be asked to do at the end of the hearing.

Preparing a preliminary outline of the structure of the reasons before the hearing begins serves several useful functions:

i. it identifies for the tribunal the issues truly in dispute, the relief sought and the initial positions of the parties on each issue;

ii. it can serve as a roadmap for understanding the evidence which is led during the hearing, particularly if the evidence is adduced in a somewhat scattered fashion on the issues;

iii. it enables the tribunal to be alive to shifts in the parties' positions and the relief requested as the hearing unfolds;

iv. by identifying the issues in dispute, the outline assists the tribunal in assessing objections made to evidence on the basis of lack of relevance to the issues at play in the hearing; and,

v. it provides an overview of the entire matter which proves useful in reflecting upon the decisions which the tribunal will be called upon to make.

Understanding and organizing the issues before the hearing commences is the single most useful device to inform the tribunal's decision-making thought process as the hearing unfolds.

5 Mr. Justice Dennis Lane, *How to get Judicially Reviewed in an Infinite Number of Easy Lessons: A Report from the Trenches*, The Canadian Institute, June 11, 2007.

Some tribunals will have access to staff to assist them during the hearing. The temptation always exists to draw upon the staff to review the pre-filed evidence and to assist in creating an outline of the reasons. Yet tribunal members must be alive to two issues. First, the law requires that only those who hear the parties' representations can participate in the decision-making process. Accordingly, the job of resolving contested evidence is that of the tribunal, not of staff. Second, as a practical matter, the more a tribunal cedes review and organizational work to staff, the less the opportunity for tribunal members to review and to inform themselves about the evidence, the positions of the parties and the dynamic of evolving evidence during the hearing. High quality decision-making results from members who personally are well-versed in the evidence and the arguments. The more a tribunal delegates the review of the evidence and argument, the more the tribunal risks lowering the quality of its ultimate decision. While the temptation to delegate can be great where the volume of evidence filed is large, at the end of the day it is the tribunal members who are paid to make the informed, reasonable decision, not staff. There is no substitute for the extensive involvement of tribunal members in the review and the organization of the evidence and arguments.

The Key Factors When Writing Decisions

If justification, transparency and intelligibility are the end-goals for any decision, how do you get there? By employing in your reasons clarity, proximity, context, the "courage of selection", and by answering the key question: Why?

Clarity: Reasons must clearly identify the issues for decision and identify the tribunal's reasoning in reaching the decision on each issue. Ask yourself: will the average educated person be able to understand the decision?

Proximity: Avoid first reciting all of the facts and then proceeding to conduct an issue-by-issue analysis. Place the treatment of the facts relevant to an issue in proximity to your application of the law or policy to that issue and to the decision made on that issue.

Context: Place the issues for determination in their larger context. For example, is the issue a "one-off", fact-specific one, or does it raise considerations which go beyond the immediate interests of the parties and engage larger policy considerations?

Courage of selection: Decide only what needs to be decided and only place relevant facts in the decision. The Supreme Court of Canada has provided guidance on this point in recent years:

> Reasons may not include all the arguments, statutory provisions, jurisprudence or other details the reviewing judge would have preferred, but that does not impugn the validity of either the reasons or the result under a reasonableness analysis. A decision-maker is not required to make an explicit finding on each constituent element, however subordinate, leading to its final conclusion. In other words, if the reasons allowed the reviewing court to understand why the tribunal made its decision and permit it to determine whether the conclusion is within the range of acceptable outcomes, the *Dunsmuir* criteria are met: *Newfoundland and Labrador Nurses' Union v. Newfoundland and Labrador (Treasury Board)*.[6]
>
> This court has strongly emphasized that administrative tribunals do not have to consider and comment upon every issue raised by the parties in their reasons. For reviewing courts, the issue remains whether the decision, viewed as a whole in the context of the record, is reasonable: *Construction Labour Relations v. Driver Iron Inc.*[7]

Why? Make the "Why?" of the decision crystal clear. Explaining why you reached the decision is the most important aspect of understanding the train of thought which led you to that decision. Do not opt to obfuscate or try to avoid dealing with the difficult issues head-on. Reviewing courts have the uncanny ability to sniff-out tribunals' attempts to avoid dealing directly with key issues. Reduced deference usually results from such avoidance efforts.

As well, a tribunal should always be alive to

6 *Newfoundland and Labrador Nurses' Union v Newfoundland and Labrador (Treasury Board,)* [2011] 3 SCR 708 at paras 16-17.

7 *Construction Labour Relations v. Driver Iron Inc*, [2012] 3 SCR 405 at para 3.

the power of the language which it uses in its reasons. Be temperate in the language you use.

Some Concluding Observations

Let me conclude by offering five additional pieces of practical advice about the decision-writing process.

First, at some point in the decision-writing process the tribunal member inevitably comes up against writer's block. Creating and then following an organized, logical outline structure for your reasons is the best way to overcome writer's block. If you take the time at the start to create a good structure, the decision often writes itself - simply take the time to work methodically and patiently through the evidence on each issue and then decide the issue. If you are in doubt about your preliminary decision on a particular issue, keep going through the rest of your reasons and circle back to that issue at a later time. Often, once you have made your preliminary determinations on all issues, it is easier to go back and revisit your decision on a particular one.

Second, more often than not it is the facts of the case that drive the result. Consequently, make your findings of fact before you turn to applying the law to the facts. Of course, as with any general rule, there is always an exception. If a case raises a novel issue of law or policy, take the time to understand the law or policy before turning to the evidence. It is easier to make specific findings of fact once you understand the legal or policy context in which those findings must be made because the legal principle or policy informs the process of ascertaining whether or not evidence is relevant.

Third, although setting out the positions of each party on each issue often is a good way to structure the legal analysis on an issue, one must remember that it is the governing legal principles, not the positions of the parties, which ultimately must inform your decision-making.

Fourth, having completed a first full draft of a judgment, review and revise it several times to ensure that it addresses all the issues and provides a coherent, logical analysis of each issue which fully rests on the facts and evidence. This stage of the decision-writing process often requires going back to review the parties' written submissions and checking material facts. Several drafts of the reasons result. As part of this process, I find it helpful to read the draft reasons aloud several times. In addition to identifying typographical errors, the process of reading a decision out loud enables you to listen to your own thought process. If a portion of your reasons sound confusing, they most likely are confusing. Go back and rewrite them until they sound clear and persuasive.

Finally, on all but the most urgent of cases, employ the "overnight rule". Having completed a draft of the judgment, sit on it overnight and thoroughly review it the following morning. Often the passage of 24 hours offers the decision-maker time to clarify his thought process and improve the decision's language. ■

ALBERTA GOVERNMENT RELEASES GUIDELINES TO CLARIFY FIRST NATIONS CONSULTATION PROCESS

*Hannah Roskey**

On July 28, 2014, the Government of Alberta (Alberta) issued its *Guidelines on Consultation with First Nations on Land and Natural Resource Management* (the Guidelines). The Guidelines supplement the *Policy on Consultation with First Nations on Land and Natural Resource Management* (the Policy), which was issued in August 2013. While the Policy provides a general overview of the consultation process, the intent of the Guidelines is to outline specific consultation procedures that should be followed.

The Guidelines replace the previous 2007 document, which outlined separate consultation procedures for each government department. The new Guidelines provide a centralized process that applies to all strategic and project-specific decisions that have the potential to adversely impact First Nations' Treaty rights and traditional uses. The Guidelines came into effect on the date of their release and apply to any consultation process initiated after their release. This bulletin summarizes the procedures outlined in the Guidelines.

Roles and Responsibilities in the Consultation Process

Alberta recognizes that a duty to consult First Nations exists when three factors are present:

1. Alberta has a real or constructive knowledge of a right.
2. Alberta is contemplating a decision relating to land and natural resource management.
3. Alberta's decision has the potential to adversely impact the continued exercise of the right.

When the duty to consult is engaged, it triggers various roles and responsibilities for Alberta, project proponents, the Alberta Energy Regulator (AER), and First Nations:

- **Alberta:** The duty to consult rests with Alberta. Alberta has created the Aboriginal Consultation Office (ACO) to provide consultation management services, which include providing pre-consultation assessments, advice and direction through the consultation process, and a decision or recommendation on consultation adequacy.
- **Project proponents:** Alberta may delegate certain procedural aspects of

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consultation to the project proponent, namely, contacting First Nations, presenting and describing project plans, and modifying project plans in response to concerns raised during consultation. The Guidelines indicate that a "proponent's guide to consultation" is presently being developed to further clarify this process.

- **AER:** Under section 21 of the *Responsible Energy Development Act*, the AER has no jurisdiction to assess the adequacy of Crown consultation. However, the ACO will work closely with the AER to ensure that any necessary consultation occurs prior to the AER's decision.
- **First Nations:** First Nations are expected to respond to notifications of proposed decisions or activities to advise whether their Treaty rights or traditional uses may be affected. First Nations are also expected to work with Alberta and project proponents to avoid, minimize, or mitigate project impacts to their rights.

Process and Timelines for Consultation

The Guidelines outline six broad stages of consultation:

1. **Pre-consultation assessment:** When a request is received, the ACO will conduct a preliminary assessment of the project to determine if consultation is required.
2. **Information sharing:** After receiving a request, the ACO will consider the project information and any available information regarding Treaty rights and traditional uses in the project area to determine whether consultation is required, and if so, at what level.
   - **Determining the level of consultation:** The level of consultation relates to the nature of the project and its potential impacts on Treaty rights and traditional uses. It dictates the scope of the consultation and what steps are necessary: Level 1 projects require "streamlined" consultation, which involves notification with an opportunity for the First Nation to respond;
   - Level 2 projects require "standard" consultation, which involves notification with an opportunity for the First Nation to respond and required follow-up by the proponent; and
   - Level 3 projects require "extensive" consultation, which involves preparation of a consultation plan, notification with an opportunity for the First Nation to respond, and required follow-up by the proponent.
3. **Exploring concerns:** Once a proponent has provided an information package to the First Nation and followed-up as needed, the proponent is encouraged to consider options to avoid, minimize, or mitigate impacts to Treaty rights and traditional uses. Exploration of those concerns should be thoroughly documented in the consultation record, and when consultation adequacy is assessed it will take into account the proponent's efforts to address First Nation concerns.
4. **Verifying the consultation record:** Proponents must send a copy of the consultation record to the First Nation for review.
5. **Determining consultation adequacy:** For AER approvals, the ACO is responsible for determining whether consultation is adequate. In other cases, the ACO will provide a recommendation to the Crown decision-maker as to whether consultation is adequate.

Depending on the level of consultation that is required, the timelines for each stage may vary. However, the Guidelines recognize that timelines may need to be extended in certain circumstances.

Appendices to the Guidelines provide "sector-specific consultation matrices" as a planning tool for proponents and to support transparency with First Nations. The matrices identify the

nature of an activity and its potential impact, and propose the depth of consultation that may be required in the absence of other factors. Alberta indicates that the Guidelines may be updated annually to incorporate feedback from government ministries, First Nations and proponents. ■