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Utility Law Meets Net Zero

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Decisions Commented on: Ontario Energy Board, "Decision and Order, EB-2022-0200, Enbridge Gas Inc, Application for 2024 Rates – Phase 1", December 21, 2023 [Enbridge Decision]; British Columbia Utilities Commission, "FortisBC Energy Inc. Application for Certificate of Public Convenience and Necessity for the Okanagan Capacity Upgrade Project", Decision and Order G-361-23, December 22, 2023 [Fortis Decision].

Utility connections for gas, electricity, and water tend to be long-lived, capital-intensive projects that typically depreciate over the expected life of the asset. At the same time, depreciation rates should also reflect the risk that an asset may be abandoned or cease to be "used and useful" before the end of its physical life. To give an easy (non-climate) example, suppose that a mine seeks an electrical utility connection. The dedicated distribution line that the mine requires might be expected to have a useful life of 40 years, but the mine itself only has proven reserves for a twenty-year life. If the local utility provides service, it will seek approval to depreciate that line over a maximum of a 20-year period. If it were to use a 40-year period and the mine shut down as expected when the ore body was exhausted after 20 years, the utility would have a stranded asset; that is to say it would have an asset that had lost its utility before the end of its physical life and for which the utility could not obtain a return *of* the undepreciated cost of the asset (50%).

How, then, should we treat an application from a natural gas utility in 2024 that wishes to continue to be able to provide natural gas service to new sub-divisions? Should the utility be allowed to continue with current policies (business as usual), which might be premised on a depreciation period of forty years? Or should such a policy be adjusted to take account of government commitments to reduce greenhouse gas (GHG) emissions or to achieve net zero? And, if so, which commitments are relevant and what types of adjustments should be considered?

These were the issues in a recent important decision of the Ontario Energy Board (OEB) dealing with Enbridge Gas Inc (Enbridge), the largest gas utility in Canada and one of the largest in North America. Similar considerations are present, but at a smaller scale, in a decision handed down by British Columbia's Utilities Commission (BCUC) a day later, this time involving FortisBC Energy Inc (Fortis).

The Enbridge Decision

This decision was part of Enbridge's first rebasing application for ten years, its first cost of service proceeding since the amalgamation of Union Gas with Enbridge in 2017, and "the first OEB proceeding to consider a gas rates application in the context of the energy transition" (Enbridge Decision at 9). It is therefore a "big deal" – not only for Enbridge and its customers but also for the Government of Ontario. The decision was released on December 21, 2023 and the following day, Todd Smith, Ontario's Minister of Energy issued a press release ("Ontario Government standing up for Families and Businesses"), denounced the decision, and indicated that he "will use all of my authorities as Minister to pause the Ontario Energy Board's decision. At the earliest opportunity, our government will introduce legislation that, if passed, would reverse it, so that we protect future homebuyers and keep shovels in the ground." Enbridge for its part filed a motion on January 29, 2024 asking the Board to review the decision. According to the Narwhal and other sources, Enbridge has also appealed the decision to Ontario's Divisional Court.

The Panel's decision is strongly informed by the prospect of an "energy transition" which the Panel refers to as "the impacts and changes to the energy system and the energy supply mix that result from efforts to reduce greenhouse gas [GHG] emissions by reducing dependence on fossil fuels, along with the use of renewable natural gas, hydrogen, and carbon capture technologies, to combat climate change" (Enbridge Decision at 9). The Panel noted that the pace and shape of the energy transition will be guided by both provincial and federal policies. On the federal side, the Panel noted that

> The Government of Canada has committed to reducing greenhouse gas emissions by 40% below 2005 levels by 2030, and to net-zero emissions by 2050 through the *Canadian Net-Zero Emissions Accountability Act*. To reduce greenhouse gas emissions, the Government of Canada has implemented an escalating carbon price, increasing annually from $10/ tonne CO2e (carbon dioxide equivalent) in 2018 and reaching $170/tonne CO2e by 2030.
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> (Enbridge Decision at 11)

Provincial commitments included a commitment to reduce GHG emissions by 30% below 2005 levels by 2030, and the adoption of regulations for large emitters aligned with the carbon price in the federal legislation.

These commitments are surely consequential for a natural gas utility and yet, as both the Panel and intervenors noted, Enbridge proposed a significant (and increased) capital spend ($1.4 billion a year compared with an actual spend of $1.1 billion a year for the *previous* five years) "based on a forecast that shows continued growth in natural gas peak demand, extending the historic trendline, with a very small impact from the energy transition" (Enbridge Decision at 20). At the same time, Enbridge argued that the ongoing energy transition exposed it to enhanced business risk, which the Panel should recognize by allowing it to enhance the equity element in its capital structure (the "equity thickness" issue). The Panel did not mince words:

> On the one hand, Enbridge Gas describes an increase in risk to justify an increase in the revenue it earns from its investment. On the other hand, it does not adjust its proposed capital spending to account for this risk. Enbridge Gas cannot have it both ways. It is this dissonance that leads the OEB to conclude that the proposed system expansion is not rational, and that Enbridge Gas has not established the prudence of its proposal. … The OEB is left with the clear conclusion that the energy transition is underway, it creates a risk of stranded asset costs, and that Enbridge Gas has not addressed this in any meaningful way. The OEB is not satisfied that Enbridge Gas's proposal will not lead to an overbuilt, underutilized gas system in the face of the energy transition

> (Enbridge Decision at 22; and see also at 67).

The Panel considered various aspects of Enbridge's proposed capital spend through an energy transition lens, including: system expansion, system renewal, depreciation and legacy site restoration.

System Expansion

Under the current scheme, Enbridge must assess expansion proposals (i.e,. adding new customers such as a residential subdivision) to determine if the utility will be able to recover the costs of the expansion over a specified time period or "revenue horizon" (currently 40 years). Should a shortfall be projected, then Enbridge would seek an additional payment from the customer, typically in the form of an upfront Contribution in Aid of Construction (CIAC).

Parties in the hearing generally took the view that Enbridge's proposal to continue with a 40-year revenue horizon was totally unrealistic given the risk that customers would have to move away from gas within that time horizon, thereby enhancing the risk of stranded assets. That led parties to discuss reducing the time horizon somewhat from 40 years, but in the end the panel (Commissioner Allison Duff dissenting on this point, at 142 – 145, "Zero is not a horizon") settled on zero with the result that all new customers (in practice, subdivision developers) will be required to make a CIAC.

There are several advantages to such an approach. First, it reduces the stranded asset risk to zero since the customer will assume the full cost of the expansion from the outset. Second, by confronting the developer with this entire cost, the OEB also eliminates the so-called split incentive problem whereby "[t]he developer makes the decision on how to service the development and the purchasers pay the energy bills" (Enbridge Decision at 34). This might lead developers to make an informed choice not to connect to the gas system at all but instead to install heat pumps or other electrical heating and cooling systems. This would likely result in some overall efficiencies since it avoids the retrofit costs that will arise were a connected gas furnace customer to install a heat pump at some time in the future when their gas furnace needs to be replaced (roughly 18 years). It also avoids having to worry about whether (assuming a gas connect) the time horizon should be fixed at 15, 18, or 20 years, or some other number in order to avoid the stranded asset risk. The panel summarized the discussion and its decision on this point as follows:

> When a developer is faced with the full cost of including gas service in a development, that developer will be fully incented to choose the most cost effective, energy efficient choice in a manner that not only achieves efficiency in the cost of housing in a competitive market and lowers the operating cost of that housing, but also maximizes the contribution to achieving government decarbonization policy goals. It also eliminates the split incentive problem.
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> This issue does not lend itself well to an incremental approach. The various proposed reductions to the revenue horizon, other than the zero option, all include the split incentive problem to varying degrees, while the zero option avoids it completely.
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> (Enbridge Decision at 41)

System Renewal

In addition to system expansion, the OEB also addressed the significant capital investments associated for system renewal to "maintain the ability of the system to provide customers with natural gas services. System renewal assets include compressor stations, distribution pipelines, distribution stations and utilization assets that regulate system pressure" (Enbridge Decision at 50) Here again the panel's main conclusion was that "Enbridge Gas did not identify any adequate steps in its application to mitigate the stranded asset risk for system renewal investments resulting from the energy transition" (*ibid*). Since system renewal spends also pose stranded assets risks, the panel considered this approach inadequate. It therefore encouraged Enbridge to think more creatively and holistically about alternatives, including repairing rather than replacing facilities and even incentive mechanisms that might see "investment by the utility to cover the cost of the electric equipment to be recovered over time, with a return on that investment" (Enbridge Decision at 52). The Board anticipates exploring these issues further in Phase 2 of this proceeding. For some of the types of legal issues that might arise in implementing any such scheme see (in the context of US utility law), Nicholas Wallace et al, *Removing Legal Barriers to Building Electrification* (2020)).

In conclusion, the Board directed Enbridge to reduce its projected capital spend for 2024 by $250 million (or 17%). It also directed Enbridge to file an asset management plan that was more responsive to energy transition issues and also to consider (in ways that recall the NEB's TCPL Restructuring Decision from 2013, RH-003-2011) "changes to its approach to depreciation to account for the impact of the energy transition, recognizing that a failure to act prudently in relation to the risk of stranded assets will have an impact on the ability to keep those assets in rate base" (Enbridge Decision at 58).

Depreciation

The Board returned to the depreciation issue in the context of energy transition later in its report when it noted that a utility needed to keep the implications of the transition front and centre. A utility is not entitled to say that "if an investment was considered prudent when assets first went into rate base, then the utility is entitled to fully recover the depreciation expense regardless of whether the assets remain used and useful" (Enbridge Decision at 83). Instead, this issue "needs to be addressed in the utility's depreciation policy" (*ibid*). Since Enbridge had failed to do so, the Board declined to approve some changes that Enbridge had proposed to its depreciation policies and instead directed Enbridge "to carry out a proper assessment of risk and determine the extent to which that risk should be addressed in its depreciation policy" (Enbridge Decision at 83; and see also at 92).

Legacy Site Restoration

Concerns about the implications of the energy transition for legacy site restoration costs also led the Board to issue specific directions to Enbridge to ensure that this did not continue as an unfunded liability (Enbridge Decision at 94)

Conclusion on the Enbridge Decision

In this decision, the OEB sends a clear message to natural gas utilities. Business as usual won't cut it. Utilities must take reduced GHG targets and net zero emissions targets seriously. The risk of stranded assets, especially those associated with new capital investments is real and must be managed as indeed must the risk to assets in service. However, as noted in the introduction, the decision itself is also at risk. While Enbridge's appeal to the courts and its application for review and variance of the decision are to be expected, the Minister's immediate, ill-considered, and visceral reaction is not. If the Minister follows through with his plans to statutorily reverse the decision, he will set an unfortunate precedent in which powerful utilities will make their case at a political level rather than before the independent regulator. See Ian Mondrow's valuable post: "Why bother with an independent energy regulator?"

The Okanagan Capacity Upgrade Project Decision

While the Enbridge decision involved a re-basing for the purpose of incentive rate-setting, this decision of the British Columbia Utilities Commission (BCUC) dealt with an application from Fortis for a certificate of public convenience and necessity (CPCN) for a specific project, namely the Okanagan Capacity Upgrade Project (OCUP) to upgrade Fortis' supply infrastructure in the Okanagan to meet anticipated increase in demand for natural gas. The project involved the construction, installation, and operation of approximately 30 kilometres of new pipeline and associated facilities with a total projected cost of some $327.410 million and with a 2.37 percent impact on Fortis' rate base. Fortis also has another application before the BCUC, namely its Revised Renewable Gas Comprehensive Review (RRGCR) application, the purpose of which is to enable all new residential connections to receive 100 percent renewable gas. The Commission's decision on that application was pending at the time of this decision. That presented a challenge to Fortis since Fortis also had to acknowledge that it could not meet projected requirements under various provincial climate policy measures including requirements under the CleanBC Roadmap, the BC Energy Step Code, and the BC Building Code unless its RRGCR application were approved in full (Fortis Decision at 15 – 17).

The Commission commented as follows:

> The basis for FEI's justification for constructing the OCU Project is that the growth of population and development in the Okanagan region is robust, and the growth curve will continue unabated. The three peak demand forecasts all support this although with significant variability between them. Of particular concern to the Panel is FEI's admission that none of its forecasts have considered the potential for a flattening or even a reversal of the curve due to commitments in the CleanBC Roadmap and the impacts of changes to the BC Energy Step Code, other planning guidelines or zoning bylaws. Despite such potential risks, FEI has maintained a 'business as usual' approach to its forecasting with the expectation there will be a continued increase in peak demand over the next 20 years.
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> (Fortis Decision at 24)

But, as the Commission observed, if the RRGCR application were to be "denied in whole or in part, the forecast peak demand growth … is highly unlikely to occur" (*ibid* at 24). And should that happen, then, along with "significant risk of demand attrition over time as the existing building stock is replaced or if customers leave the system for other reasons," the result would be that that "the OCU Project, as currently scoped, will be significantly oversized for [Fortis'] long term requirements." (*ibid* at 25)

As a result, the Commission rejected the "OCU Project at this time because we find it is not necessary for the public convenience and does not conserve the public interest" (*ibid* 24). Instead, the Commission directed Fortis to consider other measures to meet a possible shortfall in its ability to meet peak demand. It also invited Fortis to complete a new peak demand forecast once the RRGCR decision becomes available.

> Once that forecast is completed, we encourage [Fortis] to review options like a shorter pipeline or perhaps combine a series of alternatives that are designed to address the capacity shortfall, while minimizing the risk of stranded assets and costs to ratepayers.
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> (Fortis Decision at 25)

While this was the only express reference to the "risk of stranded assets" in the decision, it is clear that the BCUC shares the OEB's concerns that natural gas utilities need to take account of government climate policies (in this case the BCUC only referenced provincial climate policies) and the resulting energy transition.

What About Alberta's Utilities Commission?

I am not aware of a similar decision from the Alberta Utilities Commission (AUC) but reading these two decisions did bring to mind the AUC's extraordinary and byzantine decision from 2021 dealing with ATCO's acquisition of the so-called Pioneer Pipeline (see my earlier post: "The Regulation of Gas "Utility" Transmission Pipelines in Alberta"). This pipeline was originally constructed by non-utility investors in 2018/19 to provide gas to the Sundance and Keephills power plants, which were converting from coal to gas. The federally regulated Nova Gas Transmission Limited (NGTL) agreed to buy the pipeline from those investors but it also agreed to transfer most of the pipeline to ATCO pursuant to something called the Alberta System Integration Agreement of 2009 between NGTL and ATCO. The transfer from NGTL to ATCO led to ATCO's application to have the AUC approve the acquisition and the rate base treatment of the acquisition.

Interveners contested the application on several grounds. One concern was that the generators had only committed to a firm contract for 15 years on the pipeline while the depreciation life of the pipeline was 67 years! (Pioneer Pipeline Decision at para 32). The Commission did not share this concern, principally it seems because the revenues that ATCO would receive under the existing contracts would cover the cost of the acquisition (*ibid* at para 38). There is no discussion in the decision of stranded asset issues, GHG emission issues, or an energy transition. Indeed, the Commission's summary observation was to the effect that

> there is no persuasive evidence of intergenerational risk to ratepayers that would result from the purchase of the Pioneer pipeline. ATCO Pipelines has established that the costs of the pipeline would be recovered over the life of the asset, with revenues projected to exceed the revenue requirements associated with the purchase price.
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> (Pioneer Pipeline Decision at para 45)

An application by one party for permission to appeal was denied: *Western Export Group v Alberta (Utilities Commission),* 2021 ABCA 349 (CanLII). One of the grounds for that appeal was that the AUC had erred on the basis that the AUC had "concluded that the acquisition was needed and prudent without evidence about carbon price increases under federal greenhouse gas legislation" (*ibid* at para 17(f)). Justice Barbara Veldhuis' response was short and to the point: "I was not provided with any legal authority that the AUC must consider evidence about carbon price increases under federal greenhouse gas legislation" (*ibid* at para 40.)

And What About Electric Utilities?

If the future for natural gas utilities is declining throughput, defections from the system, and stranded assets, the future for electric utilities is entirely different. Here the questions are more about the investments needed at the distribution level to cope with things like the increased penetration of roof top solar (distributed generation) and the demand (although perhaps in the future also the potential storage value) of electric vehicles. The AUC recently released a report on a Net-Zero Analysis of Alberta's Electricity Distribution System, available here.

Conclusions

The OEB Panel decision in the Enbridge matter is a refreshing read and it challenges utility regulators across the country – particularly those that regulate natural gas systems – to take the ongoing energy transition seriously. The BCUC independently reached a similar conclusion, albeit on a smaller scale. If the Enbridge decision survives its existential political challenge, it will be interesting to observe the ripples of the decision across the country.

This post may be cited as: Nigel Bankes, "Utility Law Meets Net Zero" (9 February 2024), online: ABlawg, http://ablawg.ca/wp-content/uploads/2024/02/Blog_NB_Utility_Net_Zero.pdf