Chambers
Global Practice
Guides

Definitive global law guides offering
comparative analysis from top-ranked lawyers

Alternative Energy & Power 2021

Canada
Trends & Developments

Vivek Bakshi and Hazel Saffery
Dentons Canada LLP

practiceguides.chambers.com

Trends and Developments

Contributed by:
Vivek Bakshi and Hazel Saffery
Dentons Canada LLP ***see p.9***

Energy Innovation and Transition in Canada

In our summary of Trends and Developments this year, we have decided to pick up on the dominant theme of the moment – the path to net zero and the requirements for this sector to transition and innovate from what it has done in the past and how it has done it. In this respect, we consider geothermal energy, the increased role of hydrogen in the energy mix and the renewed focus on distributed energy resources. Each has a role to play on the path to net zero in Canada, and each area draws upon expertise and knowledge that exists in abundance in the Canadian energy sector but each will require new approaches to funding, with business models measuring successful outcomes.

Geothermal in Canada

Geothermal is a sustainable, abundant and developing energy resource. While on a global basis, countries have used this form of energy production for decades, we are seeing increased interest and new technologies championed as a method to reduce greenhouse gas emissions. Accordingly, the Canadian geothermal energy industry will continue to see significant project advances in 2021, with a growing number of pilot projects currently underway.

What is geothermal energy?

The heat required for non-polluting geothermal energy is naturally occurring and is produced from deep within the Earth. The energy is produced from wells that are drilled into the Earth's crust and through which heat energy is extracted, typically by using water and steam. There are several uses for geothermal energy depending on the location of the well and the temperature of the water or heat. Low-to-medium temperature geothermal resources are useful for water and space heating purposes. High temperature geothermal resources (greater than 150°C) can be harnessed to produce electricity by using the (fresh or brine water) steam produced from geothermal heat to turn generator turbines.

Although geothermal energy is currently a small player in Canada's energy mix, a number of promising attributes and recent innovation has led to increased interest in geothermal technology as a stable source of renewable energy. One of the key advantages of geothermal energy is its reliability and consistent power generation, meaning it has the potential to provide baseload electricity (ie, it can meet minimum power demand levels 24 hours a day, 365 days a year). Furthermore, after construction, geothermal energy emits low-to-zero greenhouse gases. Concerns with geothermal energy include the accidental release of CO2 and hydrogen sulphide emissions stored in the Earth's groundwater that is often used to carry geothermal heat to the Earth's surface. Additionally, the upfront costs for geothermal energy production are relatively high; it is expensive to carry out the seismic sensing, test well drilling, and other necessary preliminary investigations to ensure new geothermal plants will be capable of meeting desired production. Canada is uniquely positioned to meet these challenges, as its oil and gas industry can provide a significant portion of the required expertise (fracking, horizontal drilling, seismic) and infrastructure necessary to establish a booming geothermal industry.

Geothermal development in Western Canada

The highest temperature geothermal reservoirs in Canada are located in the Western Provinces and Territories. These provinces and territories have recently implemented measures to stimulate geothermal energy investment, and a number of promising projects in these jurisdictions are currently in development.

Alberta

The government of Alberta recently passed the Geothermal Resources Development Act (the "Act") to establish a licensing regime for deep geothermal resource operations. The Act is modelled on the provincial Oil and Gas Conservation Act and will be managed by the Alberta Energy Regulator (AER). As with oil and gas operations, a licence will be required to drill or operate a well (or to rework an existing well or facility for geothermal purposes) and the AER has broad discretionary authority over compliance and enforcement, operational matters, monitoring, and closure activities. Alberta has several projects in development and it is expected that more will be announced over the next year. Terrapin Geothermics Inc's "Alberta No 1" project is Alberta's first conventional geothermal power facility. In development near Grande Prairie, Alberta the facility aims to generate approximately 10 MW of baseload power, as well as also providing 985 TJ/year of baseload heat to a nearby industrial park.

Eavor Technologies is using a "closed loop" power generation facility near Rocky Mountain House, Alberta. The technology uses two vertical wells which connect many horizontal wells in a closed buried "pipe" system. Eavor then uses its "fluid" to circulate this system and collect the heat from the geothermal resource. This heat is then used to generate electricity.

Tapping into both federal and provincial funding resources and straddling carbon-based energy and renewables, a subsidiary of Razor Energy Corp (a junior oil and gas company) is developing a geothermal-natural gas hybrid power project near Swan Lake, Alberta. The first stage is expected to produce up to 3 MW of green geothermal electricity. In the planned second phase of the project a natural gas turbine will be added to optimise the geothermal power efficiency. Upon completion of both stages, this energy transition project is expected to generate 21 MW of electricity, 30% of which would be classified as renewable.

Saskatchewan

While Saskatchewan does not have legislation specifically relating to geothermal projects, it has included a number of geothermal projects in its Integrated Resource Information System, the province's business support system that facilitates the development and regulation of the energy and resources industry. The government of Saskatchewan, along with the federal government, is funding Saskatchewan's first 20 MW power plant. The project is being developed by Deep Earth Energy Production Corp, and the project is targeted for construction completion in early 2022.

British Columbia

Like the AER in Alberta, the BC Oil & Gas Commission oversees all aspects of geothermal development in British Columbia. Given that British Columbia is situated on the Pacific Ocean "Ring of Fire", British Columbia has legislation protocols in place for the development of geothermal resources. British Columbia's legislation includes the Geothermal Resources Act and the related Geothermal Operations Regulation. The Clarke Lake Geothermal Development Project, wholly owned by the Fort Nelson and Saulteau First Nations, recently received a CAD40 million commitment from the federal government and is expected to generate 7–15 MW of clean electricity and will be operational by 2024.

Looking ahead

Like any emerging venture, geothermal energy requires significant capital investment from both the public and private sector to spur further development. On a national scale, Canada's renewable position is currently dominated by wind and hydro technologies. Given technological advances and proper investment, geothermal energy has the potential to diversify Canada's renewable energy portfolio as the easily accessible high-temperature geothermal resource basins offer Canada an advantage that many other jurisdictions do not have. With the large availability of subsurface data from oil and gas development and current drilling infrastructure, Canada can leverage its expertise in well exploration to establish a foothold in geothermal electrical production. Provided further legislative and regulatory schemes are implemented to attract investment opportunities, geothermal energy could provide a substantial portion of Canada's energy needs. An established geothermal energy industry in the country would also help Canada meet its emissions reduction goals, while also creating economic opportunities for the communities where geothermal facilities are located.

The Hydrogen Economy

The Canadian government, in December 2020, issued its "Hydrogen Strategy for Canada" (the "Strategy"). The Strategy signals the growth of a hydrogen economy to be a priority, as part of the broader initiative of energy transition and innovation to drive a low-carbon future, but also as a means to drive a post-COVID-19 pandemic economic recovery. In this respect, the Strategy follows the lead shown by a number of countries worldwide. From a Canadian perspective, the Strategy cites the potential for clean hydrogen to "deliver up to 30% of Canada's end-use energy by 2050, abating up to 190 Mt-CO2e of GHG emissions." The Strategy is in addition to several provincial hydrogen initiatives, including in Alberta and Quebec.

Hydrogen in Canada today

Canada is presently a top-ten global producer of hydrogen, with its 3 Mt production of hydrogen coming predominantly from steam methane reformation processes, which use natural gas as a feedstock and produce CO2 as a by-product. This produces "grey" hydrogen (which is not the path to a low-carbon future), although the Quest Carbon Capture and Storage Project at the Scotford steam methane reformer units in Alberta, is a notable exception, with CO2 being captured and stored as part of that hydrogen production process. Grey hydrogen is predominantly used in Canada as feedstock in petroleum refining, bitumen upgrading, ammonia production, methanol production and steel production.

The goal

The Strategy anticipates both "blue" or low-carbon hydrogen and "green" or zero-carbon hydrogen being part of the initiative. Blue hydrogen would be produced from natural gas using the carbon-intensive steam methane reformation process but, as with the Quest Carbon Capture and Storage Project, production would be coupled with carbon capture and storage to significantly reduce emissions. Zero carbon or green hydrogen would be produced by electrolysis of water, using power generated by non-emitting projects.

The goal is two-fold: (i) green and blue hydrogen to replace the grey hydrogen used in Canada today, and (ii) increasing the role of hydrogen in the energy supply mix. Increased use of hydrogen could include for storage of excess power and generation of power, in fuel cells to power vehicles and as a direct substitute for hydrocarbons. The Strategy also envisages Canadian-produced hydrogen to be a key part of the global trade of hydrogen.

The challenge

Increasing the presence of hydrogen in the Canadian energy supply mix and increasing its demand will be impacted by cost parity, with the relative cost of blue and green hydrogen compared to hydrocarbons (and grey hydrogen) being key. Reduction of supply-side costs (equipment, renewable power, raw materials, transportation) is obvious to ensuring success (and there will be a number of ways of achieving this). On the demand-side of the energy mix, policy makers and regulators will need to address the challenge of levelling the playing field; to ensure the true cost of carbon-intensive fuels is paid by end-users and/or to mandate, in certain applications, the increased adoption of hydrogen through regulation.

Another challenge is exemplified by a recent precedent, that of Canada's attempt to become a leader in the global production of LNG. With over 20 projects at one time vying to export LNG from Canada, there are now just a handful of liquefaction projects still in development, with just one having taken a positive FID (two further positive FIDs are potentially coming in 2021). Challenges with the Canadian regulatory process, contributing to issues relating to the cost of development in Canada, have made the export of LNG from Canada a case of an opportunity missed, but perhaps not lost – it is hoped that hydrogen exports do not go the same way.

What comes next

The hydrogen economy as a driver to a low-carbon future presents a number of fascinating regulatory, legal and commercial issues that will need to be addressed at each step of the value chain. In Canada, however, it does seem that a hydrogen economy will be a key component in a low-carbon future, as it ensures that the oil and gas industry has a place in and can provide a bridge to, that low-carbon future. This is critical given the importance of this industry to the Canadian economy but, in addition, it would also appear to play to Canada's strengths. Canada is the fourth largest producer of natural gas globally, and existing infrastructure and expertise in the oil and gas sector would appear to make blue hydrogen an obvious opportunity for domestic supply and export.

Furthermore, Canada's power generation capacity is among the lowest for carbon intensity in the world, with significant hydroelectric and nuclear capacity and increasing renewables capacity, making production of green hydrogen a natural fit given this generation mix.

In order to seize the opportunity, however, policy and regulatory changes will be necessary at federal and provincial levels. The Canadian government signalled its intent in its most recent budget, by moving to reduce supply-side costs for hydrogen production by introducing changes to tax legislation to facilitate increased deductibility of costs for developers (through capital cost allowances) and indicated that investment tax credits will also be offered to encourage development. Similar incentives are anticipated at provincial level.

In addition to the provision of incentives, increasing stringency in carbon-pricing regulation will be key but, given the political sensitivity of this issue, the identity of the political party in government will continue to have significant bearing on this issue. Federal regulation in the form of the Clean Fuel Standards is in the process of being implemented, intended to drive lower-carbon intensity in liquid fuels (and potentially encourage adoption of alternative technologies for transportation). Additional regulation in relation to vehicle emissions, zero-emission vehicles, emission-free zones and de-carbonisation of natural gas networks have also been highlighted as necessary, but as yet still remain forthcoming – more will need to be done.

Contributed by:** Vivek Bakshi and Hazel Saffery, **Dentons Canada LLP

Distributed Energy Resources

A key trend in the Canadian electricity sector is the proliferation of technology aimed at increasing efficiency and reducing emissions. In many Canadian provinces, rapid advancements in technology, specifically, distributed energy resources (DERs), have been brought into focus by net-zero targets being set and the role that DERs may play in this. However, the existing regulatory framework governing the construction and operation of electrical systems also needs to evolve at the same pace. The following discussion will identify a few of these challenges and identify trends for the modernisation of the regulatory framework.

What are DERs?

There does not appear to be agreement on a prescriptive definition of DERs between jurisdictions. In the Alberta Utilities Commission's (AUC's) Distribution System Inquiry (24116-D01-2021), DERs have been defined by the AUC to include any technology that is connected to the distribution grid and affects the supply of and/or demand for electricity. DER technologies can include supply-side (ie, solar panels), demand-side (ie, load shedding) or energy storage facilities (ie, battery storage).

Whereas DERs have been defined by the Ontario Energy Board (OEB) in a presentation "Defining the Scope & Approach to Work Based on Stakeholder Input" (20 February 2020) as "any resource capable of providing energy services located at the distribution system level (in front or behind the meter)". The working definition states that:

- "[d]istribution level generation and storage are DERs";
- "[a] controllable load can be a DER when it offers a service by committing in advance to adjust consumption in response to system needs at a specific time or location"; and
- "[e]nergy efficiency does not have the same characteristics (eg, system impacts) as DERs but may be relevant to specific issues and should be considered".

What are the benefits and issues with DERs?

DERs are generally seen as a positive development which may contribute to the reduction in CO2 emissions, decreased use of transmission lines, increased self-consumption, and the increasing independence of customers from the centralised power grid. Moreover, there is strong consensus among regulators and utilities that DERs can help avoid or defer investment in new distribution capacity (subject to the decision by the AUC, discussed below). Further studies are required to determine whether DERs provide other ancillary benefits such as distribution resiliency and reliability, reducing distribution operation and maintenance costs and increased voltage and power quality.

Local governments in Canada have also recognised the need to reduce CO2 emissions (eg, the City of Toronto's climate action strategy) and DERs may assist local governments in achieving their net-zero objective. DERs employ small-scale technologies to produce, store or dispatch electricity closer to the end use of power. In many places, implementation of DERs results in decentralisation of the power grid and reduced reliance on large, remote power stations that have traditionally been carbon intensive (ie, coal or natural gas fired generation in Alberta).

DERs, however, may create operational and economic issues for electrical utilities. The implementation of DERs within the current regulatory framework in Alberta and Ontario, for example, poses several challenges. One of the primary issues with DERs in the current provincial regulatory framework is tariff avoidance, which was succinctly set out by the AUC:

"[...] tariff avoidance is a key motivation for installing DERs. This incentive is present in all DER-related installations and configurations used for self-supply, including supply-side DERs, demand-side DERs, self-supply with export and microgrids. Transmission and distribution tariffs, in conjunction with rate designs that have historically focused primarily on recovering total revenue requirements, rather than sending accurate price signals, and which have relied on, and are constrained by, simple metering arrangements, have created strong incentives to avoid tariffs. As explained [...] tariff avoidance leads to cost shifting among customers, and uneconomic bypass of the grid, contrary to the public interest. Left unchecked, cost transfers resulting from tariff avoidance will strengthen the incentive for other customers to similarly bypass the system, exacerbating the harm and launching a vicious cycle of rising utility rates and more customers choosing to bypass the system by way of self-supply."

Future rate design will need to address the primary consequence of tariff avoidance, which is cost shifting from one group of customers to another, and the restrictions placed on utilities, particularly in relation to ownership and control of DERs, from replacing tariffs lost to DERs. Furthermore, changes to legislation may be needed to broaden and align the permitted use of non-wire solutions by allowing contracts for DERs to be capitalised, thus allowing utilities to earn a return on their investment.

Current status of DERs in Ontario and Alberta

Ontario and Alberta are seen as leaders in Canada for the development of a regulatory framework to deal with DERs. The OEB convened three proceedings to develop a more comprehensive regulatory framework that facilitates investment and operation of DERs on the basis of value to consumers, and supports effective DER integration so the benefits of sector evolution can be realised: (i) Utility Remuneration (EB-2018-0287); (ii) Responding to Distributed Energy Resources (EB-2018-0288); and (iii) by combining (i) and (ii) into the Framework for Energy Innovation: Distributed Resources and Utility Incentives (EB-2021-0118). The OEB is in the process of studying DERs and soliciting comments from parties interested in contributing to the development of a DER regulatory framework in Ontario.

The AUC convened proceeding 24116 and released its final report on its Distribution System Inquiry on 19 February 2021, examining the need to modernise Alberta's distribution system to realise benefits from advancing technologies. As a result of feedback from stakeholders, the AUC committed to a number of actions to address identified undue regulatory barriers to new technology adoption, such as:

- modernising the regulatory framework for electricity storage;
- establishing transparent price signals;
- designing tariffs to deliver efficient outcomes; and
- improving connection practices for storage projects.

It is not clear when the AUC will propose changes to its governing legislation to remove regulatory barriers and allow new electricity technologies to develop.

Looking ahead in the electricity industry

Both the OEB and AUC recognise the need for amendments, to the least extent possible, to existing legislation, regulations and rules to accommodate DERs and to address issues that may not have been contemplated at the time of drafting. Furthermore, both regulators also appear to acknowledge that transition in the electricity industry is already underway. The AUC has indicated that the most efficient solution to the uneconomic bypass issue is to set rates based on the costs to produce and deliver network services.

On 7 June 2021, the AUC issued Decision 26090-D01-2021, wherein the AUC phases out distribution connected generation (DCG) credits, on a declining basis, over a four-year period because they unnecessarily increase the payments ratepayers make for transmission service, and these additional payments are not offset by a proven quantifiable benefit to the ratepayers. There were several findings in this decision of interest to DERs:

- there was insufficient evidence to support the view that DCG reduces transmission costs in the long term in the current regulatory environment, since DCG credits do not account for whether transmission wire costs are actually deferred or avoided in respect of where the DCG is located;
- no ratepayer pays a lower bill for avoided transmission access charges due to DCG, in the short or long term – the costs of the transmission system are largely sunk, and the presence of DCG credits is later reconciled in the annual true-up process, which only serves to inflate the DCG credit payments; and
- DCG credits create an unlevel playing field, which distorts the wholesale electricity market and harms ratepayers as a result.

While neither the OEB nor the AUC has provided comprehensive direction on how issues related to DERs will be addressed, there are several areas where changes or clarifications can be expected:

- rate design;
- modernising metering systems;
- design standards for DERs;
- ownership of DERs;
- connection practices;
- the role of DERs as no-wire alternatives;
- greater access to information and data; and
- jurisdiction between regulators (DFOs, TFOs, IESO, MSA, etc) and system planning.

Dentons Canada LLP is known as one of the world's premier firms for energy work of all types and in all jurisdictions, including power generation and transmission, distribution and supply of electricity, as well as oil and gas (upstream, midstream and downstream). Clients look to the firm's lawyers for innovative business and legal solutions across the power generation industry, including biofuel, biomass, carbon capture and storage, geothermal, hydrogen, hydroelectric, landfill gas, run-of-river, solar, natural gas, nuclear, waste to energy, wave and tidal, and on and offshore wind. The breadth and depth of Dentons' global reach and local knowledge mean the team is able to support its clients wherever their project is located, and successfully lead them through the laws and regulations that surround the industry.

The firm would like to thank Colm Boyle and Stewart Maier for their contribution to the chapter.

AUTHORS

Vivek Bakshi represents clients in the energy, natural resources and infrastructure sector. He specialises in the structuring, negotiation and documentation of natural resource projects and related financings, and in domestic and cross-border mergers and acquisitions in the oil, gas, water and power sectors. Before joining Dentons Canada LLP, Vivek previously practised at a leading English law firm in its London and Tokyo offices and has a great deal of international experience in Europe, the Middle East, South-East Asia and the Far East. Vivek has considerable expertise in regulated electricity markets and has acted for numerous clients in the development, operation and acquisition of independent power projects, including those involving renewable energy sources.

Hazel Saffery is a partner in the energy group at Dentons Canada LLP and has extensive experience in both the oil and gas industry and the power industry. Based in Calgary, Hazel advises clients on energy acquisitions and divestitures, corporate transactions and the development of independent power projects (including renewables and co-generation projects). She has acted for producers (oil and gas) and generators, midstreamers, power developers, power offtakers and service providers in a wide range of natural resource projects both in Canada and internationally. Hazel provides expert advice with respect to power development projects and transactions. Stemming from her regulatory practice, Hazel also advises commercial clients on the transactional and operational implications of the regulatory frameworks of the relevant industry.

Dentons Canada LLP

850 – 2nd Street SW
15th Floor
Bankers Court
Calgary
Alberta T2P 0R8
Canada

Tel: +1 403 268 7000
Fax: +1 403 268 3100
Email: vivek.bakshi@dentons.com
Web: www.dentons.com/en