Emerging technologies in energy

Environmental and regulatory considerations for Western Canada

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ENVIRONMENT & ENGINEERING

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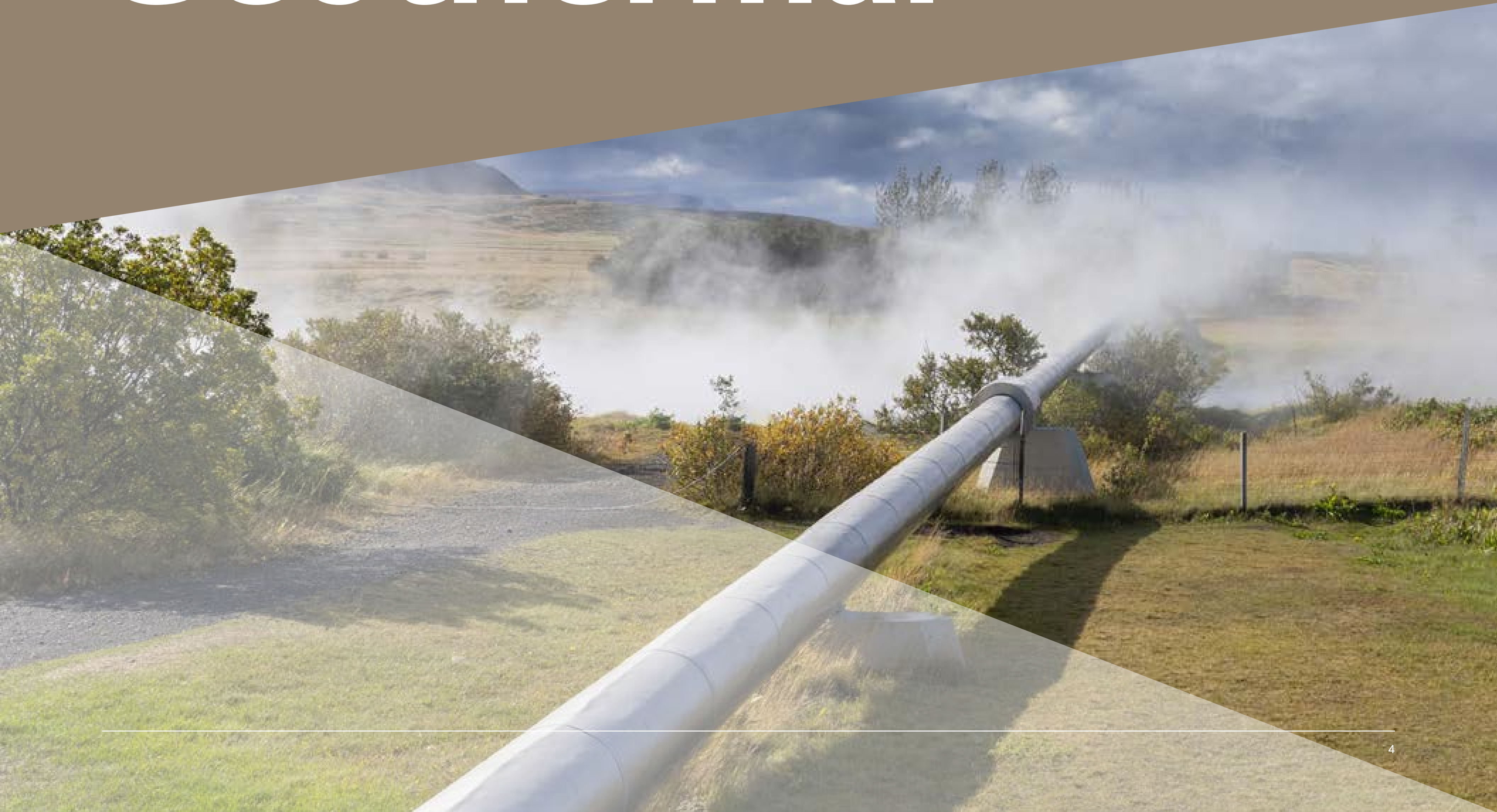
Introduction

Recent years have seen the emergence of new technologies in energy, driven largely by the global shift away from conventional fossil-fuel energy sources toward low-carbon sources of energy and new means of harnessing them. These emerging technologies include those for geothermal, lithium, and hydrogen resources, which have been the subject of rapid policy and regulatory developments in Canada. Geothermal, lithium, and hydrogen technologies are expected to continue to advance in the coming years, as they are increasingly adopted and implemented in Canada and globally.

The physical setting and resource development experience in Western Canada present tremendous opportunities for meaningful growth in the development of these energy resources. However, as is to be expected with emerging sectors, there are uncertainties with respect to the environmental risks and regulatory frameworks that apply, which considerations and regimes are largely in a state of flux.

Osler's legal experts in conjunction with environmental specialists at Matrix Solutions Inc. have created a three-part series that discusses the current environmental and regulatory considerations in Alberta, British Columbia and Saskatchewan associated with the development of geothermal, lithium and blue hydrogen resources.

Geothermal



Introduction

Geothermal energy offers a number of advantages as a renewable energy source and is an important component of Canada's transition to a low-carbon energy future. In comparison to the intermittent output of traditional renewable energy sources, such as solar or wind power, it can provide constant, predictable baseload power year-round, with little fluctuation of power output. With proper reservoir management, geothermal resources are renewable in the sense that their thermal capacity can be assessed and designed to be maintained and replenished over the life of the power plants. In addition, geothermal power facilities typically have a small land footprint and a low carbon footprint, and consume less water than conventional power plants. Another perceived advantage in Western Canada is the potential to utilize the skillsets and experience of an existing oil and gas workforce and associated technologies, as well as the possibility of re-purposing some oil and gas infrastructure.

Within Canada, prospective high temperature geothermal resources have been identified in British Columbia, the Northwest Territories, Yukon and Alberta.[1] Several geothermal power projects at various stages of development currently exist in these jurisdictions with some attracting significant federal support in early financing rounds. These include projects located within the lower mainland of British Columbia, the foothills of the Rocky Mountains in Alberta and on the prairies in Saskatchewan. While several demonstration projects and feasibility assessments have been completed in recent years, two key projects currently in the design phase include a planned 5 MW geothermal power plant near Grande Prairie, Alberta and a plan for multiple small, scalable 20 MW geothermal power plants in southern Saskatchewan, near Estevan. Several other smaller scale projects, at earlier stages of development, are also underway in B.C. and Alberta.

1 S. E. Grasby et al, *Geothermal Energy Resource Potential of Canada* (Geological Survey of Canada, 2012), http://geoscan.nrcan.gc.ca/starweb/geoscan/servlet.starweb?path=geoscan/fulle.web&search1=R=291488%0APembina.

Process description

Geothermal energy production is the harnessing of thermal energy from the naturally occurring thermal gradient within the earth. Around the world, this practice is common in areas with extensive volcanic and magmatic activity. In Western Canada, geothermal potential exists in deep portions of the Western Canada Sedimentary Basin (sometimes in excess of 3,000 m below ground surface) where basinal fluids and rock can reach temperatures above 80°C, as well as within mountainous metamorphic and igneous terrane complexes with magmatic root systems hosting geothermal fluid systems. Fluids in these deep aquifers can be produced at temperatures ranging from approximately 70°C to greater than 125°C. The hot fluid is brought to surface and the heat is captured for use in power generation or heating.

Environmental considerations

The main task when developing a geothermal energy project is to safely drill and complete the necessary wells to the required depths. This type of deep drilling is comparable to drilling in the oil and gas sector and the potential environmental concerns (e.g., management of drilling fluids, presence of entrained gas) are well understood. Accordingly, it is expected that these concerns will be managed consistently within the existing frameworks that regulate the environmental aspects of oil and gas drilling within each province.

One option under consideration by some geothermal energy developers is repurposing existing oil or gas wells. Under this scenario, the environmental liability of the existing infrastructure needs to be understood and managed. Typical due diligence activities associated with liability transfer (i.e., Environmental Site Assessments) can be used to quantify environmental liability. The liability management frameworks vary in each province and may require modifications to consider the geothermal potential of the infrastructure to offset the environmental liability (as discussed further below). However, there may be few existing oil or gas wells completed deep enough to safely access areas with material geothermal potential or with sufficient casing diameter to accommodate the pump sizes required for commercial scale development.

During operations, the main environmental consideration is the potential for brine release. Most concepts consider a facility designed to contain the brine fluid within a closed loop system where it is pumped to surface, cooled and then reinjected into the same formation. Geothermal facilities will need to be designed to consider appropriate response measures in the event of accidents or malfunctions related to brine handling. Operational maintenance plans would also need to consider the potential for scaling and fouling of pumps, piping and equipment. Depending on the chemistry of the fluids, robust integrity programs may be required to minimize the potential for releases. These environmental considerations are comparable to those encountered at existing oil and gas facilities and it is expected they will be managed in accordance with the existing approaches in the oil and gas sector.

The main task when developing a geothermal energy project is to safely drill and complete the necessary wells to the required depths.

Regulatory considerations

Of the provinces surveyed, B.C. has a dedicated regulatory regime for geothermal energy development that has existed for many years, and Alberta has recently passed legislation to create such a regime. Saskatchewan does not have a dedicated regulatory regime, although geothermal projects have been accommodated to some extent within the existing oil, gas and mineral resource regulatory regimes. Aspects of the regulatory regimes in these provinces that may be of interest to geothermal project proponents are outlined below.

Alberta

Alberta recently passed legislation to create a dedicated regulatory regime for geothermal resources, which addresses issues of ownership and access, licensing and liability.

Definition of the resource

In Alberta, there is a statutory definition for geothermal resources based on depth. The *Geothermal Resource Development Act* (GRDA) defines the geothermal resource as "the natural heat from the earth that is below the base of groundwater protection."[2] The base of groundwater protection is defined in the *Water Wells and Ground Source Heat Exchange System Directive* published by Alberta Environment and Parks (AEP) as "the best estimate of the elevation of the base of the formation in which non-saline groundwater occurs at that location"[3] (i.e., the depth at which groundwater is estimated to transition from non-saline to saline at a given location).[4] Given that there are not significant heat resources above this depth in Alberta for industrial applications, the effect of this definition is that the GRDA's provisions relating to ownership, tenure, licensing and liability apply in respect of any heat resource that would realistically be considered for an industrial-sized geothermal project.

The definition of the geothermal resource as "natural heat" from the earth excludes other categories of resources. For example, it excludes waters that may contain heat or minerals dissolved in those waters. This means that tenure and licensing of geothermal resources under the GRDA does not give ownership, tenure and licensing in respect of water or dissolved minerals, such as lithium.

2 *Geothermal Resource Development Act*, SA 2020, c. G5.5, s. 1(1)(d).
3 *Geothermal Resource Development Act*, SA 2020, c. G5.5, s. 1(1)(a);
Water Wells and Ground Source Heat Exchange System Directive, s. 1.2(2)(c).
4 These depths can be found on the Alberta Energy Regulator's website: http://www1.aer.ca/ProductCatalogue/378.html.

Ownership and access to the resource

In Alberta, title in geothermal resources has been vested in the owner(s) of the mineral title. According to section 10.2 of the *Mines and Minerals Act* (MMA),

> **Geothermal resources**
> **10.2** The owner of the mineral title in any land in Alberta has the right to explore for, develop, recover and manage the geothermal resources associated with those minerals and with any subsurface reservoirs under the land.[5]

This means that the provincial Crown owns the geothermal resource in most cases, given that it owns approximately 80% of mineral titles in Alberta. Freehold mineral rights cover the other 20%, which is generally located in the more populated areas of the province.[6]

This approach to the ownership of geothermal resources in Alberta has been criticized on the basis that, on freehold lands with split mineral title, a company would likely be required to obtain a grant of geothermal resource rights from each mineral title owner to be able to proceed with clear title, which could be difficult. For example, there could be separate owners of petroleum, natural gas and coal. In such a case, a company would likely require a grant of geothermal resource rights from each owner and, while each such owner would have geothermal resource rights, they would not be able to exercise their rights without a grant from the others.

Moreover, at common law, the surface title owner may own the geothermal resource rights (rather than the mineral title owner) and, if that is the case, section 10.2 of the MMA may not be clear enough to transfer title to the mineral owner(s), as intended. If the surface title owner owns the geothermal resource rights, there would be greater potential for subsurface conflicts resulting from the rights to extract different resources (e.g., oil, gas and geothermal) being held by different parties. For example, conflicts could arise if activities to extract one resource impact another resource (e.g., oil and gas activities resulting in incidental extraction of geothermal resources and/or negatively impacting the recovery of geothermal resources).

Without clearer legislative direction, clarification of ownership and control of geothermal resources in Alberta may require resolution through litigation. Further, if ownership is transferred from the surface title holder to the mineral rights owner, issues of expropriation may arise, similar to those that arose from the declaration that the Alberta Crown owns pore space in 2010.[7] Unlike the pore space case,[8] there is currently no statutory bar to expropriation claims by surface owners in respect of geothermal resources in Alberta.

Without clearer legislative direction, clarification of ownership and control of geothermal resources in Alberta may require resolution through litigation.

5 *Mines and Minerals Act*, RSA 2000, c. M-17, s. 10.2.
6 For a map of Crown and non-Crown mineral holdings, see https://open.alberta.ca/dataset/53e7a692-c60f-49fb-b1d5-58f7c3f33d59/resource/8824ff78-653b-421e-ab5a-ce31a765e0a5/download/mapfreehold.pdf.
7 *Mines and Minerals Act*, RSA 2000, c. M-17, s. 15.1; Paul Negenman, "Why is the Crown Stealing from Fee Owners?" (2011) The Negotiator: The Magazine of the Canadian Association of Petroleum Landmen 3.
8 *Mines and Minerals Act*, RSA 2000, c. M-17, s. 15.1(4).

For geothermal resource rights owned by the Crown, section 54 of the MMA prohibits any person or company from recovering them unless the person or company is authorized to do so under the MMA or by an agreement.[9] A person or company may be authorized to do so under an agreement entered into with the minister, on behalf of the Crown, respecting the exploration for or the development and recovery of such geothermal resources.[10] In the future, a person or company may also be authorized to do so via a tenure regime for geothermal resources established by regulation, as was done with pore space for carbon sequestration.[11] The Lieutenant Governor in Council has the power to legislate a geothermal resources tenure regime by regulation,[12] but has yet to do so.

A person or company with the right to explore for, develop and/or recover geothermal resources will also require surface rights so they can exercise those rights, whether in respect of Crown or private resources. The Lieutenant Governor in Council has the power to make regulations respecting surface access and consents required for the development of geothermal resources,[13] but has yet to do so.

Closely linked to Crown ownership and tenure is the question of royalties. An agreement entered into between a company and the Crown respecting the exploration for or the development and recovery of Crown-owned geothermal resources may also address the amounts payable to the provincial Crown (the owner) on such exploration or development and recovery.[14] Alternatively, the Lieutenant Governor in Council has the power to make regulations respecting the amounts payable to the provincial Crown in relation to such exploration, development or recovery (i.e., royalties),[15] but has yet to do so. Until any such regulations are in place, royalties are expected to be set on a case-by-case basis through site-specific geothermal tenure agreements.

Licensing regime

The GRDA establishes a licensing regime for geothermal resource exploration and development that is modelled after the *Oil and Gas Conservation Act* (OGCA) and regulated by the Alberta Energy Regulator (AER).[16] A licence must be applied for and obtained from the AER to drill a deep geothermal well or to

9 *Mines and Minerals Act*, RSA 2000, c. M-17, s. 54(1).
10 *Mines and Minerals Act*, RSA 2000, c. M-17, s. 9(a)(v.1).
11 *Carbon Sequestration Tenure Regulation*, Alta Reg 68/2011.
12 *Mines and Minerals Act*, RSA 2000, c. M-17, s. 5(1)(a)(iii.1).
13 *Geothermal Resource Development Act*, SA 2020, c. G5.5, s. 27(e).
14 *Mines and Minerals Act*, RSA 2000, c. M-17, s. 9(a)(v.1).
15 *Mines and Minerals Act*, RSA 2000, c. M-17, ss. 5(1)(w.8); 36(1)(l).
16 *Geothermal Resource Development Act*, SA 2020, c. G5.5, s. 1(1)(g); *Responsible Energy Development Act*, SA 2012, c. R-17.3, ss. 1(1)(j)(ii.1), 2.

operate any geothermal well or facility[17] (including repurposed oil and gas wells or facilities[18]), which may be granted on any terms and conditions that the AER considers appropriate. Licences may be amended on the AER's own motion or on application by the licensee and may only be transferred with the written consent of the AER, subject to any conditions that the AER considers appropriate.[19] The AER has the authority to cancel or suspend a licence (in the event of non-compliance or if equipment or operations are improper, hazardous, inadequate or defective), and it may also shut down a well or facility and direct remedial actions be taken.[20]

As with oil and gas developments, the AER has various powers to enforce the licensing regime, including powers to inspect and investigate,[21] to direct or take steps for the suspension or abandonment of a well or facility,[22] to direct or take remedial action in the event of a substance release[23] and to suspend directors and officers from engaging in ongoing or future geothermal operations.[24]

Like the OGCA, the GRDA also gives the AER the power to make rules respecting many matters,[25] including licensing, operations, waste management, monitoring and compliance, suspension and abandonment, security requirements, conservation and management of geothermal resources and location of geothermal operations. The AER may also designate a geothermal well or facility as a well or facility for the purposes of the OGCA.[26] The GRDA further gives the Lieutenant Governor in Council the power to make regulations respecting several matters,[27] including access to geothermal resources, applicability of other energy resource enactments to geothermal resources[28] and prescribing things as not being wells or facilities for the purposes of the GRDA. Given that the GRDA was only recently enacted, no such rules or regulations have been made yet.

Geothermal resource activities in Alberta are also subject to environmental laws of general application, such as the *Water Act* and the *Environmental Protection and Enhancement Act* (EPEA).

[T]he GRDA also gives the AER the power to make rules respecting many matters... [and] the Lieutenant Governor in Council the power to make regulations. ... [N]o such rules or regulations have been made yet.

17 *Geothermal Resource Development Act*, SA 2020, c. G5.5, s. 7.
18 *Geothermal Resource Development Act*, SA 2020, c. G5.5, s. 8.
19 *Geothermal Resource Development Act*, SA 2020, c. G5.5, s. 9.
20 *Geothermal Resource Development Act*, SA 2020, c. G5.5, s. 10.
21 *Geothermal Resource Development Act*, SA 2020, c. G5.5, s. 12.
22 *Geothermal Resource Development Act*, SA 2020, c. G5.5, ss. 14-15.
23 *Geothermal Resource Development Act*, SA 2020, c. G5.5, s. 21.
24 *Oil and Gas Conservation Act*, RSA 2000, c. O-6, s. 106.
25 *Geothermal Resource Development Act*, SA 2020, c. G5.5, s. 26.
26 *Oil and Gas Conservation Act*, RSA 2000, c. O-6, s. 3(3).
27 *Geothermal Resource Development Act*, SA 2020, c. G5.5, s. 27.
28 An amendment to the OGCA similarly provides that, to the extent provided by the regulations to the OGCA, it applies to a well or facility as defined in the GRDA: *Oil and Gas Conservation Act*, RSA 2000, c. O-6, s. 3(2).

Under the *Water Act*, a licence is required for any "diversion of water,"[29] which is defined as "the impoundment, storage, consumption, taking or removal of water for any purpose."[30] However, certain diversions of water are exempt from the requirement for a licence including, notably, the diversion of saline groundwater.[31] Given that the GRDA only applies in respect of the heat resource at depths where the groundwater is saline, it is difficult to imagine a geothermal project regulated under the GRDA that would require a *Water Act* licence, in light of this exemption for the diversion of saline groundwater.

Under the EPEA, an approval or registration is required for any "activity" designated by the regulations. The Schedule of Activities provides a list of such activities for the purposes of the Act, including

- the construction, operation or reclamation of a plant, structure or thing for the recovery, transfer, injection or storage of natural heat from the earth for the purpose of heating
- the drilling or reclamation of a water well or borehole
- the drilling, construction, operation or reclamation of a well other than a water well (including a well that is for exploration or development of deep geothermal resources)
- any other activity that requires an approval under the *Water Act* or a diversion of water that requires a licence under the *Water Act*
- the construction, operation or reclamation of a plant for the generating of thermal electric power or steam[32]

Of these activities, the only one currently designated by the regulations as requiring an approval or registration under the EPEA is the construction, operation or reclamation of a plant that produces steam or thermal electrical power (provided its rated production output is greater than 1 MW).[33] Accordingly, a utility-scale geothermal power plant would likely require an EPEA approval under the current regime. A provincial environmental assessment would only be required for a geothermal power plant with a capacity of 100 MW or greater or at the discretion of the director or minister.[34]

In addition, the construction and operation of a geothermal power generation facility may require power

29 *Water Act*, RSA 2000, c. W-3, s. 49(1).
30 *Water Act*, RSA 2000, c. W-3, s. 1(1)(m).
31 *Water (Ministerial) Regulation*, Alta Reg 205/1998, s. 5(1), Sched. 3.
32 *Environmental Protection and Enhancement Act*, RSA 2000, c. E-12, s. 1(a), Sched.
33 *Activities Designation Regulation*, Alta Reg 276/2003, ss. 2(2)(vv), 5(1), Sched. 1.
34 *Environmental Protection and Enhancement Act*, RSA 2000, c. E-12, ss. 39(c), 44(1)(a); *Environmental Assessment (Mandatory and Exempted Activities) Regulation*, Alta Reg 111/1993, s. 1, Sched. 1; *Environmental Protection and Enhancement Act*, RSA 2000, c. E-12, ss. 45(1), 47.

plant and connection approvals from the Alberta Utilities Commission (AUC) under the *Hydro and Electric Energy Act*[35] (applied for and considered pursuant to AUC Rule 007),[36] subject to some exceptions.[37]

While the AER currently administers the licensing regimes under the *Water Act* and the EPEA for energy resource activities within its jurisdiction, the AUC has sole jurisdiction over the assessment and approval of power plants and associated interconnections. Given that the GRDA has granted the AER authority over geothermal development, it is unclear how – or if – the AER and AUC will coordinate their processes where a geothermal project triggers licensing requirements under the two regulators' respective regimes. It is worth noting that in the case of cogeneration facilities associated with oil sands projects, which also involve licensing requirements under both the AER and the AUC regimes, the two regulators' processes have been coordinated to some extent through the AUC requesting and relying on information regarding AER approvals, which may be an appropriate approach for geothermal power projects.

Liability regime

The GRDA also establishes a liability regime for geothermal resource exploration and development that is regulated by the AER. In the case of a suspended or abandoned oil and gas well or facility, the AER may designate it as a well or facility for the purposes of the GRDA and a licence may be granted to rework it for geothermal operations.[38] When a licence to rework is granted, the former licensee is relieved from all obligations under the GRDA with respect to the well or facility except outstanding debts to the AER or to the orphan well program in respect of suspension or abandonment costs.[39] This effectively transfers the liability for the reworked well or facility to the new licensee (i.e., the licensee for the geothermal well or facility).

In the case of a remediated oil and gas well or facility (i.e., one that previously experienced a substance release with significant adverse effects), the new licensee may be liable under an environmental protection order for further remediation if there is a further substance release or substances are otherwise present in the area.[40] While this risk can be mitigated to some extent through contract, this liability exposure applies regardless of the agreements in place between prior and current licensees.

At the end of a project's life, the abandonment of a geothermal well or facility does not relieve the licensee or

In the case of a suspended or abandoned oil and gas well or facility, the AER may designate it as a well or facility for the purposes of the GRDA and a licence may be granted to rework it for geothermal operations.

35 *Hydro and Electric Energy Act*, RSA 2000, c. H-16, ss. 11, 18.

36 AUC Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* (amended August 1, 2019) (Rule 007), https://www.auc.ab.ca/Shared%20Documents/rules/Rule007.pdf.

37 *Hydro and Electric Energy Regulation*, Alta Reg 409/1983, ss. 18.1(2), 18.3(2); AUC Rule 007, s. 1.4.3; AUC Rule 024: Rules Respecting Micro-Generation (amended July 16, 2019), https://www.auc.ab.ca/Shared%20Documents/Rules/Rule024.pdf.

38 *Geothermal Resource Development Act*, SA 2020, c. G5.5, ss. 1(1)(h), 1(3)(b), 8(1).

39 *Geothermal Resource Development Act*, SA 2020, c. G5.5, ss. 8, 16.

40 *Environmental Protection and Enhancement Act*, RSA 2000, c. E-12, s. 113; *Remediation Regulation*, Alta Reg 154/2009, s. 8.

working interest participant from responsibility for the control or further abandonment of the well or facility or from the responsibility of the costs of doing that work.[41] Like reclamation costs (discussed below), costs of suspension, abandonment and remediation must be paid by each working interest participant in accordance with their proportionate share in the geothermal well or facility, unless the AER determines otherwise.[42] Similarly, the cancellation or suspension of a licence does not relieve the licensee from the liability to complete or abandon the well or facility, reclaim the site and suspend operations as the AER directs.[43]

There is also a duty under the EPEA for an operator to conserve and reclaim "specified land" and to obtain a reclamation certificate in respect thereof.[44] The term "specified land" is defined to include land that contains a geothermal well[45] and land on which there was construction, operation or reclamation of a renewable energy operation (which includes a site or plant generating renewable electricity from "heat from the earth").[46] A reclamation certificate is not required where the renewable electricity generated or produced by a renewable energy operation (e.g., a geothermal power plant) is less than or equal to 5 MW and the total footprint boundary is no greater than 1 ha in size.[47]

Where there is a duty to conserve and reclaim specified land, it must be returned to an equivalent land capability (i.e., "the ability of the land to support land uses after conservation and reclamation [must be] similar to the ability that existed prior to an activity being conducted on the land").[48] Reclamation costs must be paid by each working interest participant in accordance with their proportionate share in the geothermal well or facility, unless the AER determines otherwise.[49] Where a reclamation certificate is required for land used for a geothermal power plant (i.e., where the electricity generated is greater than 5 MW or the total footprint boundary is greater than 1 ha), an operator may be liable for an environmental protection order (EPO) regarding conservation or reclamation for up to five years after the date the certificate is issued (or longer, if an approval for the plant is held on that date).[50] Where a reclamation certificate is required for land that contains a geothermal well, an operator may be liable for an EPO for up to 25 years after the certificate is issued.[51]

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41 *Geothermal Resource Development Act*, SA 2020, c. G5.5, s. 16.
42 *Geothermal Resource Development Act*, SA 2020, c. G5.5, s. 17.
43 *Geothermal Resource Development Act*, SA 2020, c. G5.5, s. 10(3).
44 *Environmental Protection and Enhancement Act*, RSA 2000, c. E-12, s. 137(1).
45 *Environmental Protection and Enhancement Act*, RSA 2000, c. E-12, s. 1(aaa);
Conservation and Reclamation Regulation, Alta Reg 115/1993, s. 1(t)(i).
46 *Environmental Protection and Enhancement Act*, RSA 2000, c. E-12, s. 134(f);
Conservation and Reclamation Regulation, Alta Reg 115/1993, ss. 1(q.2-q.3), 1(t)(x).
47 *Conservation and Reclamation Regulation*, Alta Reg 115/1993, s. 15.1(1)(a)(vi)(B); *Micro-generation Regulation*, Alta Reg 27/2008, s. 1(1)(e)(i).
48 *Conservation and Reclamation Regulation*, Alta Reg 115/1993, ss. 1(e), 2.
49 *Geothermal Resource Development Act*, SA 2020, c. G5.5, s. 17.
50 *Conservation and Reclamation Regulation*, Alta Reg 115/1993, ss. 1(t)(x), 15(1).
51 *Conservation and Reclamation Regulation*, Alta Reg 115/1993, ss. 1(t)(i), 15(2).

British Columbia

British Columbia's dedicated regulatory regime for geothermal energy development addresses issues of ownership and access, licensing and liability. Although it has existed for 25 years,[52] this regime has long been criticized (particularly in terms of the leasing process) and no significant changes have been made to address these criticisms.

Definition of the resource

In B.C., the statutory definition of geothermal resources is based on temperature. The *Geothermal Resources Act* (GRA) defines geothermal resource as

> the natural heat of the earth and all substances that derive an added value from it, including steam, water and water vapour heated by the natural heat of the earth and all substances dissolved in the steam, water or water vapour obtained from a well, but does not include
>
> (a) water that has a temperature less than 80°C at the point where it reaches the surface, or
>
> (b) hydrocarbons[53]

The effect of this definition is that the GRA's provisions relating to ownership, tenure, licensing and liability apply regardless of depth and they apply to steam, water and water vapour heated by the natural heat from the earth and all substances dissolved therein that are obtained from a well. They do not apply to hydrocarbons or to water that has a temperature less than 80°C at the point where it reaches the surface. Geothermal resources with a temperature less than 80°C are therefore not governed by the GRA and there is no comprehensive legislative framework in place for their uses. Currently, it appears that these resources and associated activities would fall under the *Water Sustainability Act*,[54] which was not designed to address geothermal resource regulation.

Ownership and access to the resource

In B.C., ownership in all geothermal resources is vested in and reserved to the provincial government and only the provincial government may dispose of them under the GRA.[55] This avoids having to obtain a grant of geothermal resource rights from multiple owners to proceed with geothermal operations, as is the case with private mineral title owners in Alberta. It also uses declaratory language that is likely clear enough to overcome any common law claim to ownership of geothermal resources on the part of the surface title owner(s).

In B.C., ownership in all geothermal resources is vested in and reserved to the provincial government and only the provincial government may dispose of them under the GRA.

52 *Geothermal Resources Act*, RSBC 1996, c. 171.
53 *Geothermal Resources Act*, RSBC 1996, c. 171, s. 1(1).
54 *Water Sustainability Act*, SBC 2014, c. 15.
55 *Geothermal Resources Act*, RSBC 1996, c. 171, s. 2.

Section 4 of the GRA prohibits any person or company from producing a geothermal resource (other than for testing purposes) unless they have been issued a lease by the minister for the right to produce a geothermal resource from a location, subject to the GRA.[56]

For access to unoccupied Crown land for a geothermal resource activity, a company may obtain an authorization from the BC Oil and Gas Commission (BC OGC).[57] For access to private land for geothermal resource exploration, a company must enter into an agreement with the landowner authorizing the access.[58] For access to private land for geothermal resource production, a company must enter into an agreement with the landowner authorizing the access or, if they are unable to do so, it may apply to the Surface Rights Board for a right of entry order.[59]

The GRA also addresses royalties. A lessee who produces a geothermal resource (other than for testing purposes) must pay the government the royalty or amount to be paid that is established by agreement with the minister (and approved by the Lieutenant Governor in Council) or, if there is not such an agreement, the lessee must pay the prescribed royalty.[60]

Licensing regime

The GRA also establishes a licensing regime for geothermal resource exploration and development. To produce a geothermal resource, in addition to having a lease with the right to produce from the location, a company must have a production plan approved by the BC OGC and the producing well must be permitted by the BC OGC.[61] For exploration, the company must obtain a permit from the minister and an exploratory well must be authorized by the BC OGC or, if another method of exploration is proposed to be used, the BC OGC must be notified in writing using the prescribed form.[62] Each year, the company must carry out geothermal exploration of a prescribed value or make payments in lieu thereof, and the company must record all work with the minister.

A permit or lease may be transferred, without any third-party (e.g., the minister or BC OGC) consent, but only in compliance with the regulations. A permit or lease may be cancelled by the minister, in writing, if the company fails to comply with a provision of the GRA or the regulations.[63]

56 *Geothermal Resources Act*, RSBC 1996, c. 171, ss. 1(1), 8.
57 *Geothermal Resources Act*, RSBC 1996, c. 171, ss. 1(2); *Petroleum and Natural Gas Act*, RSBC 1996, c. 361, s. 138.
58 *Geothermal Resources Act*, RSBC 1996, c. 171, ss. 1(2); *Petroleum and Natural Gas Act*, RSBC 1996, c. 361, s. 144.
59 *Geothermal Resources Act*, RSBC 1996, c. 171, ss. 1(2); *Petroleum and Natural Gas Act*, RSBC 1996, c. 361, ss. 158-159.
60 *Geothermal Resources Act*, RSBC 1996, c. 171, s. 17.
61 *Geothermal Resources Act*, RSBC 1996, c. 171, ss. 1(1), 4.
62 *Geothermal Resources Act*, RSBC 1996, c. 171, ss. 4-5.
63 *Geothermal Resources Act*, RSBC 1996, c. 171, s. 10.

The BC OGC has various powers to enforce the licensing regime, including powers to inspect and investigate,[64] to suspend or revoke a well authorization[65] and to direct remedial action.[66] The Board of the BC OGC has the power to make regulations of general application and orders related to specific locations or wells, governing the drilling of wells and the production and conservation of geothermal resources.[67] The GRA also gives the Lieutenant Governor in Council the power to make regulations respecting numerous matters, including suspension and revocation of permits and leases, royalties, application of other legislation to geothermal resources, transfer of permits and leases and rent payable for leases.[68] Regulations have been made respecting many of these matters.[69]

In B.C., geothermal resource activities are also subject to environmental regulation. The *Environmental Protection and Management Regulation* (EPMR) applies to a company with a permit or lease under the GRA, albeit with the modifications set out in the *Geothermal Resources General Regulation*.[70] Under the EPMR, prior to permitting a well, the BC OGC must consider whether the issuance of a well authorization is consistent with the government's environmental objectives set out in the EPMR with respect to water quality, riparian values, wildlife and wildlife habitat, old-growth management areas, resource features and cultural heritage resources.[71] The EPMR also sets out requirements to ensure the resource activity does not cause a material adverse effect on water quality, quantity or flow or result in any deleterious materials being deposited into streams, wetlands or lakes, to conserve soil and to restore the operating area.[72]

Under the *Environmental Assessment Act*, geothermal resource activities are not reviewable and do not require an environmental assessment certificate.[73] However, a thermal electric power plant (including one that generates electricity from the use of geothermal energy) is a reviewable project requiring an environmental assessment certificate if its rated nameplate capacity is 50 MW or greater.[74]

Under the *Environmental Assessment Act*, geothermal resource activities are not reviewable and do not require an environmental assessment certificate.

64 *Geothermal Resources Act*, RSBC 1996, c. 171, s. 14.
65 *Geothermal Operations Regulation*, BC Reg 79/2017, s. 45.
66 *Geothermal Resources Act*, RSBC 1996, c. 171, s. 16.
67 *Geothermal Resources Act*, RSBC 1996, c. 171, s. 23.
68 *Geothermal Resources Act*, RSBC 1996, c. 171, s. 24.
69 *Geothermal Geophysical Exploration Regulation*, BC Reg 358/98; *Geothermal Operations Regulation*, BC Reg 79/2017; *Geothermal Resources General Regulation*, BC Reg 39/2017.
70 *Geothermal Resources General Regulation*, BC Reg 39/2017, ss. 12(1)-(2).
71 *Environmental Protection and Management Regulation*, BC Reg 200/2010, ss. 4-8, as modified by *Geothermal Resources General Regulation*, BC Reg 39/2017, ss. 12(8)-(10).
72 *Environmental Protection and Management Regulation*, BC Reg 200/2010, ss. 9-10, 12, 17, 19, as modified by *Geothermal Resources General Regulation*, BC Reg 39/2017, s. 12(7).
73 *Environmental Assessment Act*, SBC 2018, c. 51, ss. 1, 6; *Reviewable Projects Regulation*, BC Reg 243/2019.
74 *Reviewable Projects Regulation*, BC Reg 243/2019, Table 7.

Liability regime

Under the GRA, a company holding a permit or lease must keep all machinery, equipment, wells and other facilities on the location in a safe condition. This duty continues (even if the lease or permit expires or is terminated) until the BC OGC issues a certificate of restoration certifying that the land surface of the location has been restored to a satisfactory condition in accordance with the regulations, among other things. If, after the inspection of a location or well, the BC OGC considers that a method or practice being employed may constitute a hazard to the health or safety of any person or the public, a company may be liable for remediation and, if there is a delay in performing remediation, it may be ordered to cease all operations in the location or in connection with the well until remediation is completed to the BC OGC's satisfaction.[75]

Unless exempted by the BC OGC, a well authorization holder must deposit security with the BC OGC in the amount of $225,000 for a geothermal well and $7,500 for each thermal gradient well drilled with respect to the same formation (to a maximum of $50,000). There is no requirement to return the security unless and until a certificate of restoration has been issued in respect of all the company's authorizations or the security is no longer required to secure the company's obligations under the GRA.[76]

Responsibilities under the *Contaminated Sites Regulation* to remediate a contaminated site apply to a geothermal operation if there is a concentration of a substance in the soil or at the site that exceeds the prescribed standard or concentration for that substance.[77]

Saskatchewan

Saskatchewan does not have a dedicated regulatory regime for geothermal development, although geothermal projects have been accommodated to some extent within the existing oil, gas and mineral resource regulatory regimes.

Definition of the resource

In Saskatchewan, there is no statutory definition of geothermal resources and no legislation regulating geothermal projects specifically. Geothermal project applications can be submitted through the Government of Saskatchewan's Integrated Resource Information System, where geothermal projects are defined:

75 *Geothermal Resources Act*, RSBC 1996, c. 171, s. 16.
76 *Geothermal Operations Regulation*, BC Reg 79/2017, ss. 47-48.
77 *Contaminated Sites Regulation*, BC Reg 375/96, s. 22, Part 5.

> A geothermal project means a development where geothermal energy is recovered through deep well(s). There are two main types of geothermal project; open-loop and closed-loop. An open-loop system includes: (1) withdrawing formation water for the purpose of extracting geothermal energy as part of an industrial process, and (2) disposing the cooling fluids into subsurface following the extraction of its heat content. In a closed-loop system, the source fluids are circulated in a sealed wellbore – heat exchange loop and there are no formation fluids to be withdrawn or fluids to be disposed. The geothermal project application is only applied to the subsurface activities.[78]

In the Government of Saskatchewan's guidance for disposal wells, geothermal projects are defined:

> A geothermal project means a development that geothermal fluids are produced from a water source well, the geothermal energy is recovered at surface as part of an industrial process for any purpose, and the cooling fluids are disposed into subsurface through a waste disposal well.[79]

Based on these two definitions, the Government of Saskatchewan appears to apply a definition of geothermal resources that is based on depth ("geothermal energy is recovered through deep well(s)") and includes deep subsurface water with geothermal energy. Based on the approvals that have been issued for geothermal activities to date (discussed below), the Government of Saskatchewan appears to classify geothermal resources as minerals and as including minerals dissolved in deep subsurface water with geothermal energy.

Ownership and access to the resource

In Saskatchewan, there is no legislative statement regarding the ownership of geothermal resources; however, based on the approvals that have been issued for geothermal activities to date (discussed below), the Government of Saskatchewan appears to view geothermal resources as property of the provincial Crown. This is consistent with a classification of geothermal resources as minerals given that, in most cases, minerals in Saskatchewan are owned by the provincial Crown.[80] Crown ownership of geothermal resources is also supported by Crown ownership of all ground water (i.e., water beneath the surface of land) in the province, which could include deep subsurface water with geothermal energy.[81]

If geothermal resources are classified as minerals, authorization must be obtained under *The Subsurface Mineral Tenure Regulations* (SMTR) to explore for and produce them.[82] A lease of space would also be

78 Government of Saskatchewan, "Storage Project Application," https://www.saskatchewan.ca/business/agriculture-natural-resources-and-industry/oil-and-gas/oil-and-gas-licensing-operations-and-requirements/oil-and-gas-drilling-and-operations/gas-storage-and-cavern-storage-disposal.

79 Government of Saskatchewan, "Disposal Wells," https://www.saskatchewan.ca/business/agriculture-natural-resources-and-industry/oil-and-gas/oil-and-gas-licensing-operations-and-requirements/oil-and-gas-drilling-and-operations/disposal-injection-wells.

80 *See The Crown Minerals Act*, SS 1984-85-86, c. C-50.2 and *The Provincial Lands Act*, SS 2016, c. P-31.1.

81 *The Water Security Agency Act*, SS 2005, c. W-8.1, s. 38(1).

82 *The Subsurface Mineral Tenure Regulations*, RRS, c. C-50.2 Reg 30, ss. 8, 20.

necessary for subsurface access.[83] For surface access, the company must obtain the written consent of the owner and occupant or, if they are unable to do so, a company may apply to the Board of Arbitration for an order granting surface rights.[84]

Licensing regime

Saskatchewan does not have legislation establishing a dedicated licensing regime for geothermal projects. Geothermal operations have been regulated through existing mineral legislation and there are provisions in *The Oil and Gas Conservation Act* (SKOGCA) that may be used to regulate aspects of the geothermal industry.

Saskatchewan has used lease of space agreements under *The Crown Minerals Act* (CMA) to facilitate geothermal operations.[85] For example, the developer of a geothermal power demonstration plant in South Saskatchewan applied for, and obtained, a lease of space agreement.[86] As noted above, a lease of space agreement allows subsurface access, such as for geothermal resource activities.

Substances from the geothermal industry may be regulated under SKOGCA[87] in a number of ways:

- The minister may make orders, and the Lieutenant Governor in Council may make regulations, respecting containment, storage, handling, transportation, treatment, processing, recovery, reuse, recycling, destruction and disposal of substances from the geothermal industry at a licensed facility or well or associated site.[88]
- The Lieutenant Governor in Council may make regulations respecting the injection, disposal and storage of substances from the geothermal industry in subsurface formations.[89]
- The Lieutenant Governor in Council may make regulations authorizing or requiring the drilling, casing, cementing, operation and plugging of wells in accordance with good practices and in any matter as to prevent the harmful intrusion of water and substances from the geothermal industry into the environment and the pollution of fresh water supplies by such substances.[90]

In Saskatchewan, there is no legislative statement regarding the ownership of geothermal resources.

83 *The Crown Minerals Act*, SS 1984-85-86, c. C-50.2, s. 27.2.
84 *The Surface Rights Acquisition and Compensation Act*, RSS 1978, c. S-65, ss. 24-25.
85 A. Thompson, F. Bakhtheyar and G. Van Hal, "A Qualitative Assessment of Major Barriers Facing the Geothermal Industry In Canada" (2014) 38 GRC Transactions 71 at 72.
86 DeepCorp, "DEEP Drills 4 New Geothermal Wells and Increases Subsurface Rights by 700%," https://deepcorp.ca/deep-drills-4-new-geothermal-wells-and-increases-subsurface-rights-by-700/.
87 *The Oil and Gas Conservation Regulations, 2012*, RRS c. O-2 Reg 6, s. 4(1) defines "non-oil-and-gas substances" for the purposes of *The Oil and Gas Conservation Act* (including the above-listed order and regulation making powers) as include substances from the geothermal industry.
88 *The Oil and Gas Conservation Act*, RSS 1978, c. O-2, ss. 17(1)(k), 18(ff).
89 *The Oil and Gas Conservation Act*, RSS 1978, c. O-2, s. 18(ff).
90 *The Oil and Gas Conservation Act*, RSS 1978, c. O-2, s. 18(a)(v).

Currently, the only provisions in regulations made pursuant to the SKOGCA which apply in respect of non-oil-and-gas substances (including from the geothermal industry) deal with

- preventing operators of oil and gas and certain other types of wells (not including geothermal wells) from allowing such substances to constitute a hazard to public health or safety or contaminate fresh water or arable land[91]
- prohibiting any earthen structure or excavation from being used as a receptacle for such substances[92]

If a geothermal project involves a waste disposal well, detailed requirements in respect of such a well are outlined in *Directive PNG008: Disposal and Injection Well Requirements*.[93]

91 *Oil and Gas Conservation Regulations, **2012***, RRS c. O-2 Reg 6, ss. 2(1)(aa), 2(1)(xx), 53(4).
92 *Oil and Gas Conservation Regulations, **2012***, RRS c. O-2 Reg 6, s. 60(2).
93 Government of Saskatchewan, *Direction PNG008: Disposal and Injection Well Requirements* (March 29, 2018), https://publications.saskatchewan.ca/api/v1/products/76172/formats/85298/download.

Lithium

Introduction

Over the last decade, lithium has grown from having primary uses in glass and ceramic manufacturing to its now almost ubiquitous association with lithium-ion batteries. These have emerged as a key component in energy storage applications ranging from small electronic devices through to electric vehicles for decarbonized transportation. They have even been used in grid scale energy storage for load leveling and renewable energy storage. Given this increasingly important role in energy decarbonization, some forecasts suggest that lithium production will need to grow by as much as five times current outputs by 2030 to satiate the surge in demand.[1] Globally, lithium sales in 2018 were approximately US$4 billion and are on track to reach upwards of US$30 billion by 2030.[2] With such a rapid expansion of supply required and relatively slow production scaling, a significant market opportunity exists to capture a portion of this nascent supply chain in North America. In addition to the requisite increase in supply, there exists a strong incentive for diversification of this supply chain for added geopolitical stability. This stems from the extremely concentrated supply chain dominated by Australia and South America for resource production and by China for refinement and battery manufacturing. This call for new and diverse supply is exemplified by the recent declaration by the United States to include lithium in its key strategic minerals deemed essential for future national energy independence and the recently formed Canada-U.S. Joint Action Plan on Critical Minerals Collaboration.

Canada is making advancements to fully quantify and understand its inventory of lithium resources and it is evident that subsurface brines present a potentially unique and accessible resource in jurisdictions with existing oil and gas infrastructure and expertise. Brines enriched with lithium have been identified in Alberta and Saskatchewan with ongoing interest in northeast British Columbia and Manitoba. More than a dozen projects throughout these jurisdictions have now been quantified by National Instrument Standards (NI-43-101) in lithium carbonate equivalent. Notable projects with early-stage pilots include those in central and southern Alberta and in southeast Saskatchewan.

1 Gert Berckmans et al, "Cost Projection of State of the Art Lithium-Ion Batteries for Electric Vehicles Up to 2030" (2017) 10:9 Energies 1314, https://doi.org/10.3390/en10091314;
IRENA, *Electricity Storage and Renewables: Costs and Markets to 2030*, (International Renewable Energy Agency, 2017), https://www.irena.org/publications/2017/Oct/Electricity-storage-and-renewables-costs-and-markets.

2 Brian W. Jaskula, *2017 Minerals Yearbook – Lithium* (U.S. Geological Survey, 2020), https://prd-wret.s3.us-west-2.amazonaws.com/assets/palladium/production/atoms/files/myb1-2017-lithi.pdf.

Process description

Globally, lithium is currently produced from either Australian spodumene ore in open pit hard rock mining operations or through evaporative concentration of enriched brines in Andean salars. Conventional mining for mineral forms of lithium requires heavy machinery to lift and crush ore and the application of high temperatures and pressures and caustic reagents to extract the lithium. Lithium brines in South America are processed using evaporation ponds which require huge tracts of land, are prone to leaks and weather setbacks, and take two years to concentrate before producing lithium products. Canada hosts potential in both mine and brine type deposits, however the brine prospects here differ significantly from their South American counterparts as they exist within sedimentary basins of Western Canada and are often referred to as "petro-lithium brines."

Lithium development is the recovery of lithium from solution in lithium enriched brines or formation waters within oil-bearing geologic reservoirs. Like geothermal energy production, fluids in these formations are highly saline and range from depths of approximately 600 m to greater than 3,000 m below ground surface. These brines occur within reservoirs which currently produce or have produced oil and gas as well as certain formation waters. These brines are lower in lithium concentration (50 – 200 mg/L) than their counterparts in South America (300 – 3,000 mg/L), yet exist in vastly larger volumes which amount to a comparable resource in place. In addition, the technology being developed to process this brine differs from that used for South American brines given that evaporative concentration is not feasible in Canadian climates. The Canadian brine is brought to surface and treated in a central processing plant to concentrate and recover the lithium. Various technologies are being designed and tested for this purpose in Canada with some promising concepts built upon ionic exchange, membrane and nano-filtration, and forms of electrochemical separation, all of which are also considering potential synergies with geothermal energy production. The remaining fluid from processing is strategically reinjected into the source formation to maintain pressure support with special consideration for dilution effects over time.

Canada hosts potential in both mine and brine type deposits, however the brine prospects here differ significantly from their South American counterparts as they exist within sedimentary basins of Western Canada and are often referred to as "petro-lithium brines."

Environmental considerations

As with geothermal energy production, the main task when developing a lithium project is to safely drill and complete the necessary wells to the required depths. The potential environmental concerns associated with drilling these wells are comparable to those associated with oil and gas drilling. These concerns are well understood, and it is expected that the existing regulatory frameworks can be adapted as required to manage drilling for lithium development.

Because lithium-bearing formations can be shallower than formations targeted for geothermal development, there is also a higher potential to co-produce lithium from existing oil and gas wells within depleted fields.

Should lithium developers elect to repurpose existing oil or gas wells rather than drill new wells, the environmental liability of the existing infrastructure needs to be understood and managed. Potential issues associated with the ability of the existing liability management frameworks in each province to quantify the lithium asset potential of the infrastructure (in addition to the environmental liability) would need to be addressed.

One other key difference between lithium development and geothermal development is that the lithium is removed from the process when the fluid is brought to surface. To continue to recover lithium in quantities suitable for commercial production, sustaining wells need to be drilled and completed regularly throughout the life of the facility. A full commercial-scale lithium production facility could supply beyond 25,000 tonnes per annum of lithium carbonate equivalent and would theoretically process more than 100,000 m^3 of brine fluid per day from a network of wells. This requirement results in a surface disturbance footprint that is comparable to oil and gas production with many existing fields managing produced waters in these orders of magnitude. It is expected that the existing frameworks that regulate land access and terrestrial environmental effects of oil and gas development in each province can be adapted to consider lithium development.

During operations, one of the main environmental concerns would be the potential for inadvertent brine release. The development would be designed to process brine in a central facility within the well network. Brine would typically be transported in buried pipelines from the production wells to the central facility and then back to injection wells. Both the facility and the pipelines would need to be designed to consider appropriate measures to minimize the potential for spills and releases and to respond in the event of accidents or malfunctions related to brine handling. Operators would also need to evaluate and align the surface footprint of the required well networks with any regional cumulative effects management frameworks to minimize the environmental effects of surface disturbance. Again, these environmental concerns are comparable to those encountered at existing oil and gas facilities and it is expected that these concerns will be managed consistent with the existing frameworks that regulate the environmental aspects of oil and gas facility operation within each province.

Regulatory considerations

With lithium production still in its infancy, the regulatory structure governing its production is very much uncertain. This section discusses the potentially applicable regulatory regimes in Alberta, British Columbia and Saskatchewan, while flagging uncertainties and concerns arising therefrom.

Alberta

Ownership, access and royalties

Where mineral rights are owned by the province, a valid mineral lease will be required to recover the lithium pursuant to the *Metallic and Industrial Minerals Tenure Regulation* (MMTR).[3] As the Crown in right of Alberta owns approximately 80% of the mineral rights in the province, this is likely to be the most common method of obtaining ownership or the right to recover lithium. On private lands, mineral lease agreements will be required with the mineral rights owner for a given parcel.

Pursuant to the MMA, an exploration licence or permit is required to explore for minerals.[4] Prior lithium projects have applied for exploration permits under the *Metallic and Industrial Minerals Exploration Regulation* (MMER).[5] The distinction between a licence and a permit is that the latter allows for the operation of exploration equipment. As such, it is reasonable to anticipate a permit being required for the exploration of lithium. Permit applications for mineral (non-oil and gas) exploration are typically made to AEP; however, the AER has jurisdiction over the exploration provisions contained in Part 8 of the MMA for energy resources (currently limited to oil, gas, oil sands and coal).

As discussed in the Geothermal section, this framework raises the potential for overlapping mineral and oil and gas dispositions given that subsurface rights to extract different resources may be held by different parties. This is a source of uncertainty for lithium developers, as there does not appear to be a clear framework for prioritizing overlapping subsurface rights. In the ordinary course, Alberta enjoys a scheme whereby ownership of a subsurface resource provides a right to work that resource. This principle may be constrained, however, by specific priority conferred upon oil and gas resources by the AER under its public interest mandate or through express legislative priority, for instance.[6] These priorities are not tested within the context of lithium production, and therefore do not serve to remedy this uncertainty.

Production of a metallic and industrial mineral in commercial quantities pursuant to a permit or lease requires an order from the Lieutenant Governor in Council prior to extraction.[7] Importantly for lithium production, section 50(3)(c) of the MMTR provides an exemption from this requirement for such minerals extracted "in brine form," which may be interpreted to apply to lithium dissolved in water.

[T]he potential for overlapping mineral and oil and gas dispositions ... is a source of uncertainty for lithium developers, as there does not appear to be a clear framework for prioritizing overlapping subsurface rights.

3 *Metallic and Industrial Minerals Tenure Regulation*, Alta Reg 145/2005, ss. 37, 39.
4 *Mines and Minerals Act*, RSA 2000, c. M-17, s. 107.
5 *Metallic and Industrial Minerals Exploration Regulation*, Alta Reg 213/1998.
6 Rudiger Tscherning & Brady Chapman, "Navigating the emerging lithium rush: lithium extraction from brines for clean-tech battery storage technologies" (2020), Journal of Energy & Natural Resources Law, at 22-27.
7 *Metallic and Industrial Minerals Tenure Regulation*, Alta Reg 145/2005, ss. 39(1), 50(1)-(2).

There is no specific royalty rate for lithium in Alberta. Similarly, lithium does not appear to fit neatly within the royalty rate scheme set out in Parts 1-4 of the *Metallic and Industrial Minerals Royalty Regulation* (MMRR).[8] As such, it is expected that the applicable royalty rate would be provided under the general "metallic minerals royalty" as established in Part 1. We note that royalties established under Parts 3 and 4 of the MMRR are not particularly well-suited to lithium production given their reliance on tonnage produced, although the royalty under Part 1 is based on revenue from the "mine."[9] In any event, the recent adoption of a helium-specific royalty rate as announced in May 2020 may signal specific royalty rates for the production of other resources such as lithium and hydrogen. Greater certainty in respect of lithium royalties may be on the horizon.

The appropriate regulator

There is uncertainty surrounding the regulatory authority responsible for lithium production in Alberta. The AER appears to be well-suited to the role, given its expertise and jurisdiction under oil and gas legislation as well as Part 8 of the MMA, as opposed to AEP, which has limited-to-no involvement in oil and gas development and whose role under the minerals regime is generally focused on minerals that are mined.

The AER currently has jurisdiction over certain "specified enactments" in relation to "energy resource activities" pursuant to its enabling legislation, the *Responsible Energy Development Act*.[10] Such activities include those that are carried out, or "directly linked or incidental to the carrying out of an activity" in relation to any natural resource within Alberta that can be used as a source of any form of energy, not including hydro energy.[11] Lithium *per se* is not a form of energy and therefore does not appear to fit neatly within the jurisdiction of the AER for this reason. Lithium as described above, however, could be "directly linked or incidental" to carrying out an oil and gas activity in the case of co-production.

It is noteworthy that some analogous projects are regulated by the AER, such as solution salt mining.[12] Further, a number of the directives issued by the AER regarding wells appear to be directly relatable to the lithium production process. Therefore, while not *prima facie* mineral-oriented in its focus, regulation by the AER as opposed to AEP is likely to provide a clearer regulatory framework, at least in the near term. As discussed below, recent developments may resolve some of this uncertainty moving forward.

8 *Metallic and Industrial Minerals Royalty Regulation*, Alta Reg 350/1993.
9 *Metallic and Industrial Minerals Royalty Regulation*, Alta Reg 350/1993, s. 4.
10 *Responsible Energy Development Act*, SA 2012, c. R-17.3, s. 2(2).
11 *Responsible Energy Development Act*, SA 2012, c. R-17.3, ss. 1(1)(h), (i).
12 See, for example, injection well applications filed with the AER by K+S Windsor Salt Ltd., in particular application #1824568.

Licensing

Wells drilled for brine production and water disposal may be licensed under the *Oil and Gas Conservation Rules*.[13] Pursuant to the AER's directives, injection and disposal requirements for a Class II well — used for injection and disposal of produced water (brine) or brine equivalent fluids, including brine from salt caverns or solution mining operations — are likely to be required for lithium production under Directive 051.[14] Further, a licence from the AER for a water source well and water injection well as outlined in Directive 056 [15] and applications for compulsory pooling and special well spacing under Directive 065 [16] may be required.

Under the *Water Act*, an exemption from licensing requirements to divert water is provided for the diversion of "saline groundwater" pursuant to the *Water (Ministerial) Regulation*.[17] Saline groundwater is further defined by the Regulation as "water that has total dissolved solids exceeding 4,000 milligrams per litre." [18] As the aquifer brine being diverted in the lithium process is well over the 4,000 mg/L salinity threshold, a water licence is not required.

An environmental assessment may be required under the EPEA.[19] As lithium production is not enumerated as either a "mandatory activity" or an "exempted activity" under the applicable regulation,[20] an environmental assessment would fall within the general discretion of the regulator under section 41 of the EPEA.

Liability considerations

The AER requires all upstream oil and gas wells, facilities and pipelines to be regulated pursuant to its Licensee Liability Rating program, which is designed to prevent the costs of suspending, abandoning, remediating and reclaiming such projects from being borne by the Alberta public in the event a licensee becomes defunct. This program relies on a liability management rating (LMR) system which is a numeric representation of a licensee's eligible deemed assets over its deemed liabilities. Once the LMR is below 1.0, financial security is required from the licensee.

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13 *Oil and Gas Conservation Rules*, Alta Reg 151/1971, ss. 2.020, 2.040.

14 Alberta Energy Regulator, *Directive 051: Injection and Disposal Wells—Well Classifications, Completions, Logging, and Testing Requirements*, at 2.4, https://www.aer.ca/regulating-development/rules-and-directives/directives/directive-051.

15 Alberta Energy Regulator, *Directive 056: Energy Development Applications and Schedules*, https://www.aer.ca/regulating-development/rules-and-directives/directives/directive-056.

16 Alberta Energy Regulator, *Directive 065: Resources Applications for Oil and Gas Reservoirs*, https://www.aer.ca/regulating-development/rules-and-directives/directives/directive-065.

17 *Water (Ministerial) Regulation*, Alta Reg 205/1998, Sched. 3, s. 1(e).

18 *Water (Ministerial) Regulation*, Alta Reg 205/1998, s. 1(1)(z).

19 *Environmental Protection and Enhancement Act*, RSA 2000, c. E-12.

20 *Environmental Assessment (Mandatory and Exempted Activities) Regulation*, Alta Reg 111/1993, Scheds. 1, 2.

The principal concern arising from the Licensee Liability Rating program is that the LMR system is designed to quantify oil and gas assets as opposed to assets used in other types of resource development. Directive 006 notes, in particular, that licensed injection wells and brine wells as defined in Directive 056 are subject to the Licensee Liability Rating program.[21] As alluded to in the licensing section above, the AER has a wealth of technical expertise in respect of the wells and systems that would be required for lithium production. That said, as provided for in Directive 011, deemed assets are based on established netbacks, shrinkage and conversion factors which are specific to the oil and gas industry.[22] This leaves considerable uncertainty surrounding the LMR classification as it applies to lithium assets, which is unlikely to be remedied until a lithium project regulated by the AER proceeds.

British Columbia

Regulatory structure

It is possible that production of lithium from brines would be regulated in British Columbia under the GRA. The GRA provides for a broad definition of "geothermal resources" that includes "all substances dissolved in the steam, water or water vapour" obtained from a geothermal well, but does not include water that has a temperature less than 80°C at the point where it reaches the surface, or hydrocarbons.[23] In the case that a lithium project falls within this definition of a geothermal resource, its facilities will be regulated by the BC OGC pursuant to the *Oil and Gas Activities Act* (OGAA).[24]

The regulatory structure for lithium as a geothermal resource would be the same as outlined previously in the Geothermal section. In the event lithium is not co-produced with geothermal energy and does not fall within the definition of a geothermal resource, the relevant mineral regime will apply. The remainder of this section discusses this regime.

The principal concern arising from the Licensee Liability Rating program is that the LMR system is designed to quantify oil and gas assets as opposed to assets used in other types of resource development, like lithium.

Ownership, access and royalties

To secure ownership of a mineral in British Columbia, it is first necessary to obtain a free miner certificate pursuant to the *Mineral Tenure Act*.[25] This certificate furnishes the right to acquire and maintain mineral title.

21 Alberta Energy Regulator, *Directive 006: Licensee Liability Rating (LLR) Program and Licence Transfer Process*, at appendix 1, https://www.aer.ca/regulating-development/rules-and-directives/directives/directive-006.

22 Alberta Energy Regulator, *Directive 011: Licensee Liability Rating (LLR) Program: Updated Industry Parameters and Liability Costs*, at 3, https://www.aer.ca/regulating-development/rules-and-directives/directives/directive-011.

23 *Geothermal Resources Act*, RSBC 1996, c. 171, s. 1(1).

24 *Oil and Gas Activities Act*, SBC 2008, c. 36. See, in particular, *Oil and Gas Activities Act General Regulation*, BC Reg 274/2010, s. 3(1)(a).

25 *Mineral Tenure Act*, RSBC 1996, c. 292, s. 8.

Following this, a claim must be obtained for exploration and development.[26] The recorded holder of mineral title through a claim must then convert the claim to a mineral lease in accordance with the *Mineral Tenure Act* to carry out mining production.[27] To maintain a claim beyond its expiry date, prescribed development or exploration work must be undertaken and registered by the claim holder.[28] A concern arises that such prescribed work may not be amenable to solution lithium production.[29] Note that, in lieu of undertaking and registering such work, a claim holder may provide a payment instead of exploration and development pursuant to section 10 of the Regulations.[30]

Mineral royalties are provided for under the *Mineral Tax Act*.[31] To date, lithium is not enumerated as a "taxable resource" under the Act.[32] As the Government of British Columbia indicates, however, its non-inclusion does not mean it is non-taxable. Currently, applicable taxes on the resource are unknown.

Licensing

A permit for a lithium project is likely required pursuant to the *Mines Act*, which applies to the lifecycle of the mining activity.[33] The definition of a "mine" provided for in the Act is sufficiently broad to capture lithium production.[34] To obtain such a permit, an applicant must submit a detailed plan outlining, *inter alia*, reclamation of the site.

A discharge approval is required for mining projects pursuant to the *Environmental Management Act* (EMA) for effluent discharge, air emissions and solid waste. The authorization may be in the form of either a permit or an approval.[35] As an approval is only valid for a period of up to 15 months, a permit is likely required for a commercial lithium project.

The Ministry of Energy, Mines and Low Carbon Innovation and the Ministry of Environment and Climate Change Strategy allow for joint applications for *Mines Act* and EMA permits.

Mineral royalties are provided for under the *Mineral Tax Act*. To date, lithium is not enumerated as a "taxable resource" under the Act.

26 See: Government of British Columbia, *Information Update No. 7 – A Guide to Surface and Subsurface Rights and Responsibilities in British Columbia*, Revised September 2017, last accessed: January 7, 2021 (online), at 3.
27 *Mineral Tenure Act*, RSBC 1996, c. 292, s. 42.
28 *Mineral Tenure Act*, RSBC 1996, c. 292, s. 29
29 For both physical and technical development or exploration requirements, see *Mineral Tenure Act Regulations, BC Reg 529/2004, Schedule A. See also: Government of British Columbia, Information Update No. 25 – Exploration and Development Work*, https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/mineral-exploration-mining/documents/mineral-titles/notices-mineral-placer-titles/information-updates/infoupdate25.pdf.
30 *Mineral Tenure Act Regulations*, BC Reg 529/2004, s. 10.
31 *Mineral Tax Act*, RSBC 1996, c. 291.
32 Government of British Columbia, *Mineral Tax* (website), last accessed: January 7, 2021 (online).
33 *Mines Act*, RSBC 1996, c. 293, s. 10.
34 *Mines Act*, RSBC 1996, c. 293, s. 1.
35 *Environmental Management Act*, SBC 2003, c. 53, ss. 14, 15.

If proceeding under the GRA, the provisions of the *Water Sustainability Act* (WSA) do not apply.[36] Therefore, no authorization for the diversion of water is required. On the other hand, where regulated under the mining regulations, a groundwater licence to divert water from an aquifer may be required.[37] An exemption from this requirement is provided where the water is "unrecorded water," meaning the right to its diversion or use is not already held under an authorization or another enactment, and it is used for "prospecting a mineral."[38] The *Groundwater Protection Regulation* imposes additional technical requirements applicable to groundwater wells. Lithium development, however, is likely to be largely exempted[39] from these regulations, as the associated water will constitute "deep groundwater" under the regulations.[40]

An environmental assessment certificate is also required under the *Environmental Assessment Act, 2018* (BCEAA) for any "reviewable project."[41] A lithium project would only be reviewable where it has an annual production capacity of 75,000 tonnes or more.[42] This 75,000 production threshold – reflective of traditional mining figures – is unlikely to ever be met by a single lithium project and, as such, the requirement for an environmental review is unlikely to be triggered under the current regime.

As alluded to above, reclamation plans are submitted as part of permitting under the *Mines Act*. Part 10.7 of the *Health, Safety and Reclamation Code for Mines in British Columbia* sets out the standards for reclamation of such a site.[43] Pursuant to the permitting process under section 10 of the *Mines Act*, a proponent is required to pay security to the mine reclamation fund.[44]

Saskatchewan

Of the three jurisdictions profiled, Saskatchewan has what is likely the clearest regulatory structure in relation to lithium production. It is outlined under the province's mining regulations. Across multiple statutes, the definitions of "mineral" and "mine" are broad enough to cover lithium production. For example, the common definition of a mineral is "any non-viable substance formed by the processes of nature, irrespective of chemical or physical state and both before and after extraction, but does not include any

36 *Geothermal Resources Act*, RSBC 1996, c. 171, s. 4.
37 *Water Sustainability Act*, SBC 2014, c. 15, s. 6(1).
38 *Water Sustainability Act*, SBC 2014, c. 15, ss. 1(1), 6(3).
39 With the exception of the provisions outlined in s. 4(2).
40 *Groundwater Protection Regulation*, BC Reg 39/2016, s. 4(1)(a); *Water Sustainability Regulation*, s. 51.
41 *Environmental Assessment Act*, SBC 2018, c. 51, s. 6.
42 *Reviewable Projects Regulation*, BC Reg 243/2019, ss. 3(1), 9, 10.
43 British Columbia Ministry of Energy and Mines, *Health Safety and Reclamation Code for Mines in British Columbia*, https://www2.gov.bc.ca/gov/content/industry/mineral-exploration-mining/health-safety/health-safety-and-reclamation-code-for-mines-in-british-columbia.
44 *Mines Act*, RSBC 1996, c. 293, ss. 10(4)-(5), 12.

surface or ground water, agricultural soil or sand or gravel."[45] Likewise, a mine is defined as "any facility in Saskatchewan for extracting, recovering or producing any mineral except oil and gas."[46]

Ownership and exploration

Similar to Alberta, the vast majority of mineral title in Saskatchewan is held by the province. As such, it is likely that the provisions and related regulations of the CMA will apply to a lithium project.[47] In respect of the appropriate tenure scheme, lithium is expressly included within the definition of a "subsurface mineral" under the SMTR.[48] These regulations set out a streamlined process for obtaining tenure and rights to explore and work subsurface minerals.

Pursuant to these regulations, a permit is required for exploration of a mineral.[49] The permit also grants an exclusive right to develop the subsurface minerals within the permitted lands. Importantly, subsurface mineral permits are granted through a public offering process similar to that for oil and gas tenure in Saskatchewan, in which an interested party applies and the permit is issued according to a bidding process triggered by such an application.[50] This process ensures that overlapping dispositions – as present under the regulatory scheme in Alberta – are unlikely to arise. Once a project proponent is the holder of a permit, they may apply for a lease, which permits the proponent to extract the mineral.[51]

Royalties

Lithium royalties are somewhat uncertain in Saskatchewan. The dedicated SMTR currently only prescribes royalty rates for salt and potash.[52] On the other hand, the general provisions of the *Crown Mineral Royalty Regulations*, under Part II, Division II, prescribe a royalty rate for all minerals.[53] As such, it is likely that this general royalty rate applies to lithium produced, although the minister retains the right to determine the amount of the royalty payable pursuant to a mineral disposition in any particular case.[54]

Lithium royalties are somewhat uncertain in Saskatchewan. The dedicated SMTR currently only prescribes royalty rates for salt and potash.

45 *The Mineral Resources Act*, 1985, SS 1984-85-86, c. M-16.1, s. 2(1)(f); *The Crown Minerals Act*, SS 1984-85-86, c. C-50.2, s. 2(1)(i).
46 *The Mineral Resources Act*, 1985, SS 1984-85-86, c. M-16.1, s. 2(1)(e); *The Crown Minerals Act*, SS 1984-85-86, c. C-50.2, s. 2(1)(h).
47 See, in particular, *The Crown Minerals Act*, SS 1984-85-86, c. C-50.2, ss. 2(1)(d), (e).
48 *The Subsurface Mineral Tenure Regulations*, RRS, c. C-50.2, Reg 30, s. 2.
49 *The Subsurface Mineral Tenure Regulations*, RRS, c. C-50.2, Reg 30, s. 8.
50 *The Subsurface Mineral Tenure Regulations*, RRS, c. C-50.2, Reg 30, s. 7.
51 *The Subsurface Mineral Tenure Regulations*, RRS, c. C-50.2, Reg 30, ss. 18, 19
52 *The Subsurface Mineral Royalty Regulations*, 2017, RSS, c. C-50.2, Reg 32.
53 *The Crown Mineral Royalty Regulations*, RSS, c. C-50.2, Reg 29, s. 13.
54 *The Crown Mineral Royalty Regulations*, RSS, c. C-50.2, Reg 29, s. 4.

Licensing

Pursuant to *The Water Security Agency Act* (WSAA), authorization is required from the Water Security Agency before diverting, pumping or using any groundwater or constructing any works necessary to do so.[55] As distinct from Alberta's legislative scheme, there is no express carve-out for saline groundwater. The authorizations required for a lithium project would be an approval to construct works as a result of pumping such groundwater, as well as a water rights licence for the use of the groundwater.[56]

It is likely that a lithium project would fall within the broad definition of a "development" under the *Environmental Assessment Act* (SEAA), though the definition does lend itself to some discretion on behalf of the minister.[57] As such, a proposal may be submitted to the minister for determination as to whether the project is properly classified as a development pursuant to section 7.2 of the SEAA. If determined not to be a development, the minister will allow the project to proceed without an environmental assessment. Notwithstanding the broad definition of a "development," experience has shown that projects of similar scope to lithium projects are not likely to be classified as a development requiring an environmental assessment in Saskatchewan.

Further approvals from the Minister of Environment are required under *The Mineral Industry Environmental Protection Regulations* for the construction, installation, alteration, operation or temporary closure of a pollutant control facility, or to decommission and reclaim a mining site as defined in the Regulations.[58] Moreover, section 12 of the regulations provides that both a plan for decommissioning and reclamation and an assurance fund must be approved before the operation of a project.

Finally, and of limited application, where the site of a proposed project is on provincial land and the operator or site holder plans to return the site to provincial custody following decommissioning and reclamation, a release into the institutional control program is required pursuant to *The Reclaimed Industrial Sites Act* and the associated regulations.

55 *The Water Security Agency Act*, SS 2005, c. W-8.1, s. 57.
56 *The Water Security Agency Act*, SS 2005, c. W-8.1, ss. 2(t), 50, 59.
57 *The Environmental Assessment Act*, SS 1979-80, c. E-10.1, s. 2(d). See also, ss. 7.5, 7.6 evidencing the discretion of the minister.
58 *The Mineral Industry Environmental Protection Regulations*, 1996, RSS, c. E-10.2, Reg 7, ss. 3, 5, 7, 10, 12.

A path forward

In March 2019, the Government of Canada, in consultation with the provincial and territorial governments as well as other stakeholders, released the Canadian Minerals and Mines Plan, partially directed at updating mining legislation and regulatory frameworks to make them more effective in the face of a changing global mining sector. The plan looks not only to technological advancements in mining, but also to the increasing importance of specific metals and minerals, both of which are positive developments for prospective lithium producers.

A preliminary version of the first action plan under the Canadian Minerals and Mines Plan was released in March 2020. While it does not provide much in the way of substantive solutions moving forward, a few points are noteworthy. First, the plan actively points to lithium as a critical mineral, following the lead of the United States.[59] Second, the plan acknowledges the growing importance of such critical minerals to the global demand for clean energy.[60] This is especially true of lithium given its use in lithium-ion batteries and the expansion of the electric vehicle and energy storage markets globally. As such, lithium is front of mind for regulatory modernization under the Canadian Minerals and Mines Plan.

This is evident in Alberta in particular. On September 23, 2020, the Government of Alberta announced the creation of a five-member Mineral Advisory Council to "help unlock Alberta's vast, untapped geological potential for various minerals that are in increasing global demand."[61] One of the minerals expressly considered is lithium. Of principal importance to the advisory council is streamlining the regulatory environment in place for mineral development in a way that assures environmentally responsible development, enhances opportunities for indigenous peoples, promotes innovation and attracts investment.

The final strategy and action plan under the Canadian Minerals and Mines Plan are anticipated in the spring of 2021. While there is no indication at this time as to what is expected out of the provincial action plan, the focus on regulatory modernization does evidence a willingness to address some of the regulatory uncertainty mentioned above.

59 Mines Canada, *Action Plan 2020: Introduction the Pan-Canadian Initiatives March 2020 Preliminary Version*, at 2, https://www.minescanada.ca/sites/default/files/cmmp-actionplan2020_rev52_feb_29_2020-a_en.pdf [*Action Plan 2020*]. See also: Mines Canada, *Update to Action Plan 2020*, https://www.minescanada.ca/sites/default/files/pictures/PDF/cmmp_actionplan2020_update_final-en.pdf.

60 *Action Plan 2020*, at 6.

61 Government of Alberta, *Capitalizing on Alberta's Mineral Potential*, https://www.alberta.ca/release.cfm?xID=7329753D827B2-FC42-4C4C-2177ED7E26BFAABA.

Blue hydrogen

Introduction

The concept of a hydrogen economy has long been considered as an alternate means of chemical energy transport and storage for decarbonization, yet until recently it has remained a distant promise mired by significant cost and technological hurdles for large scale adoption. This situation is rapidly changing, however, as energy challenges with existing battery applications are aligning with new advancements in fuel cell technology and the use of hydrogen-natural gas blends for combustion in turbines. Increasingly in these scenarios, hydrogen is being considered as a means of converting carbon-free energy into a chemical fuel which may be able to leverage existing natural gas infrastructure and expertise.

Canada is already one of the top ten hydrogen producers in the world and as such has established supply chains supporting various applications such as petrochemicals and the fertilizer industry. Growing these supply chains provides an opportunity to leverage existing infrastructure to meet international demand as many countries look to build out national hydrogen strategies to combat the effects of climate change. Many of these countries are already significant trading partners with Canada, including Japan, China, the U.S. and a host of European nations. In fact, Canada recently acknowledged this tremendous socio-economic potential by rolling out its own National Hydrogen Strategy. Early studies have indicated that by 2050 Canadian hydrogen production could grow by up to seven times relative to today's production figures to meet global demand.[1]

Process description

Hydrogen can be produced from a variety of feedstocks, including electricity and water, biomass and industrial processes. The most common method of hydrogen production today is steam methane reforming (SMR), which involves a thermochemical reaction where natural gas or a refined petroleum product is combined with steam to release the bonded hydrogen. Within this range of options for hydrogen production, significant effort in Canada is being directed to developing low-to-neutral carbon intensity "blue" hydrogen using SMR paired with carbon capture, utilization and storage (CCUS) to prevent the carbon dioxide by-product from being emitted to the atmosphere. This outcome can be achieved with the addition of a carbon capture loop to existing Canadian SMR operations and by leveraging oil and gas expertise and the geological conditions of the prairie provinces. Successful blue hydrogen developments require plentiful sources of

1 Natural Resources Canada, *Hydrogen Strategy for Canada*, https://www.nrcan.gc.ca/climate-change/the-hydrogen-strategy/23080.

natural gas and water for feedstock and access to facilities or reservoirs to store or process the captured carbon dioxide. Blue hydrogen offers cost and scalability advantages as compared to “green” hydrogen (produced using electricity from renewables with water) and has the added benefit of redeploying existing and underemployed oil and gas expertise and leveraging existing pipeline and natural gas infrastructure.

Environmental considerations

In Western Canada, natural gas is plentiful and there are numerous existing distribution networks that can be accessed for feedstock. Depending on the location of the proposed facility, additional or expanded natural gas pipeline infrastructure may be required to provide the required volumes. There are existing frameworks to regulate natural gas pipeline development in each province (and federally) that can be applied as required.

Commercial-scale hydrogen developments also require substantial amounts of fresh water. As the water is used to make steam and is a reagent in the chemical reaction, facilities require the water source to be relatively free from impurities. As a result, water used for SMR is typically sourced from surface water bodies rather than deep aquifers. The water used in hydrogen production is also a consumptive use, meaning no water is returned to the natural source. Sourcing sufficient water to supply commercial-scale hydrogen production will result in competition with water demands for agriculture, municipal and industrial usage in Western Canada. There are also several areas within Western Canada where new water allocation is limited or constrained. Potential environmental concerns regarding water use therefore need to be evaluated and addressed.

> Sourcing sufficient water to supply commercial-scale hydrogen production will result in competition with water demands for agriculture, municipal and industrial usage in Western Canada.

Opportunities for carbon capture and storage have been identified throughout Western Canada. Existing facilities (such as the Boundary Dam coal-fired power plant in Saskatchewan and the Shell Quest project in Alberta) have demonstrated the viability of underground carbon capture. Numerous facilities have also demonstrated that carbon dioxide injection can be used as an enhanced recovery method in existing oilfields (such as those served by the Alberta Carbon Trunk Line). However, more detailed geologic evaluation is required to delineate the carbon storage potential of other areas throughout Western Canada to be able to store the volumes of carbon dioxide that would be generated from a commercial-scale hydrogen development. Additional carbon dioxide transportation infrastructure would also likely need to be developed to connect the hydrogen facility to suitable storage reservoirs, and concerns regarding the long-term potential of subsurface carbon dioxide migration over time and potential associated environmental effects would need to be examined.

During operations, an additional environmental consideration is the safe storage, handling and distribution of the produced hydrogen. Hydrogen gas containment and storage typically requires specialized equipment to reduce the potential for losses and to manage the risk of explosion. These risks are well understood at existing hydrogen storage and handling facilities. Where efforts are made to replace existing natural gas infrastructure with hydrogen infrastructure, upgrades may be needed to accommodate the safe distribution of hydrogen. This may include further development of underground storage caverns that have been used to store natural gas and natural gas liquids throughout Western Canada and the world. Should caverns be considered for hydrogen storage, environmental concerns would include securing additional source water for cavern washing, facilities to manage brine waste and ongoing monitoring to assess potential for subsurface migration of fluids. In future, storing hydrogen in a solid-state hydride may permit avoidance of the risks associated with hydrogen stored under pressure, but the associated technologies and methods are not yet sufficiently advanced to support large scale hydrogen storage and distribution.

Alternative hydrogen production technologies

While blue hydrogen is the primary focus of governments and developers in Western Canada (and the focus of this article), hydrogen technology companies are exploring two alternate means of producing hydrogen that merit mention: "green" hydrogen production and in-situ combustion.

Green hydrogen development

One alternative to SMR is the production of hydrogen through an electrolysis reaction – using energy to split a water molecule into hydrogen and oxygen. The "green" hydrogen production process uses renewable energy sources (such as wind or solar) to power the electrolysis reaction. These projects are typically most viable in areas with both abundant freshwater resources and high renewable energy potential. One key environmental concern associated with green hydrogen production is the consumptive water use, similar to what is described above for blue hydrogen development. Each green hydrogen project is also likely to entail environmental considerations associated with its form and geographic setting.

Hydrogen development through in-situ combustion

Another alternative hydrogen production method is currently being piloted in Saskatchewan. Oxygen-enriched air is injected into a depleted oil and gas reservoir, resulting in subsurface in-situ combustion. The heat from the combustion causes a pyrolysis reaction that chemically cracks the hydrocarbon within the formation, releasing hydrogen. Specialized membranes are used to separate the hydrogen from other formation fluids and produce it to surface while the remaining reaction by-products are left underground.

The potential environmental liability issues (described in the Geothermal section) related to acquiring and operating legacy oil assets also apply to this type of hydrogen development. Legacy oil and gas infrastructure's material integrity would need to be evaluated to confirm feasibility of operating in hydrogen service. In addition, there is uncertainty associated with the potential environmental effects of in-situ combustion. This recovery technique has been applied in both oil sands and conventional oil and gas reservoirs. Constant air injection into the formation requires some vapours to be vented or captured at surface to avoid overpressurization. In other applications, this process has occasionally resulted in the generation of undesirable by-products (e.g., water vapour, hydrogen sulphide) that must be managed. Other legacy oil and gas wells can also serve as preferential pathways for gases produced in the combustion reaction; these wells (if identified) would need to be plugged or remediated to avoid unplanned gas venting.

Regulatory considerations

Regulatory regimes in Western Canada do not explicitly address hydrogen developments. While policy statements from the federal and provincial governments signal that dedicated regulatory frameworks may be forthcoming to promote and streamline blue hydrogen development, these types of facilities are presently governed by existing regimes related to oil and gas and water resources.

This section describes the schemes presently applied or likely to be applied to blue hydrogen developments, including the licensing requirements related to facilities, water diversion and CCUS.

Regulatory regimes in Western Canada do not explicitly address hydrogen developments.

Alberta

Licensing

While Alberta legislation does not explicitly address hydrogen development, blue hydrogen development engages the regulatory regimes applicable to chemical facilities, water use and CCUS.

Facilities: Despite the existence of several hydrogen production facilities in Alberta, there is no express regulatory regime for the licensing of those facilities that would provide clarity to blue hydrogen project proponents.

A key consideration is the need for authorization under Alberta's EPEA, which requires approvals and registrations for designated activities.[2] While the SMR process is not explicitly designated as requiring approval or registration, analogous facilities – such as petrochemical manufacturing plants, sweet gas processing plants and chemical manufacturing plants – often do require approvals under the EPEA.[3]

The AEP has issued approvals under the EPEA for the construction, operation and reclamation of existing hydrogen facilities in the province.[4] Within the EPEA's regulatory framework, AEP appears to treat standalone SMR facilities as "chemical manufacturing plants." SMR facilities are also regulated under the

2 *Environmental Protection and Enhancement Act*, RSA 2000, c. E-12, s. 60.
3 *Activities Designation Regulation*, AR 276/2003, s. 5(1) and Schedule 1, Division 2, Part 2 (i) and (ix) and Part 8 (v).
4 Examples include Air Products Canada Ltd.'s Scotford Chemical (Hydrogen) Manufacturing Plant (Approved 6 June 2014), Air Products and Chemicals, Inc.'s Edmonton Hydrogen Plant (Approved 31 May 2016).

EPEA as integrated components of oil refineries (as with the North West Redwater Partnership's Sturgeon Refinery) and bitumen upgraders (in the case of Shell's Scotford Upgrader). While AEP is responsible for administering the EPEA regime in relation to chemical manufacturing plants and oil refineries, the AER is responsible for bitumen upgraders and gas processing plants. As such, there is uncertainty as to which regulator – the AER or AEP – will regulate SMR facilities in the future as investment in blue hydrogen production in Alberta continues to grow. This issue is further discussed below.

Application for approval under the EPEA requires detailed information, including the activity's proposed location, capacity and size, timing of its construction and operation, and information concerning potential environmental impacts and mitigations.[5] In the course of reviewing an application, the director (or the AER, as the case may be) may also request further information from the applicant and others, and require the proponent to hold meetings to provide information to the public.[6] If an environmental assessment is required, the director cannot issue an approval or registration until the assessment process is complete.[7] The director may issue or refuse an approval or registration, and may impose terms and conditions on approvals, which terms are typically quite prescriptive in nature.[8]

With respect to facility licences, the AER's licensing regime under the OGCA could be applied to blue hydrogen facilities (which are arguably "processing plants" that produce a "gas" as defined in the OGCA),[9] though to date such application has been limited to hydrogen production facilities that are integrated with facilities that traditionally fall under the OGCA (such as oil refineries and bitumen upgraders). In addition, the AER-administered *Pipeline Act* likely applies to hydrogen pipelines associated with SMR facilities, as all gas pipelines require a licence and "gas" is defined broadly as including "any substance recovered from natural gas … for transmission in a gaseous state." Therefore, even if a licence for an SMR facility is not mandated under the OGCA, AER authorization of any associated hydrogen pipeline infrastructure is likely required.

5 See *Approvals and Registrations Procedure Regulation*, AR 113/93, s. 3(1).
6 *Approvals and Registrations Procedure Regulation*, AR 113/93, ss. 5(1) and (2).
7 *Environmental Protection and Enhancement Act*, RSA 2000, c. E-12, s. 63.
8 *Environmental Protection and Enhancement Act*, RSA 2000, c. E-12, ss. 68(1) and (2)
9 *Oil and Gas Conservation Act*, RSA 2000, c.O-6, ss. 1(1)(y) and (pp).

Water diversion: A licence under the *Water Act* is required to divert fresh water for all industrial purposes, including to produce blue hydrogen.[10] Securing sufficient water allocation under licences is a key consideration in hydrogen development. The director (or, where applicable, the AER) must consider approved water management plans when deciding whether to issue a licence and under what, if any, terms and conditions.[11]

There are five water management plans in Alberta, covering distinct river basins and prescribing considerations for water allocations in their respective geographies. Notably, the water management plan for the South Saskatchewan River Basin, which covers most major southern Alberta watercourses (Red Deer and south), restricts new water allocations and has initiated a market for the transfer of licences in its region.[12]

The *Water Act* also expressly enables the director or AER to consider any applicable water conservation objective when assessing a diversion application. Currently, eight water shortage advisories are in place in Alberta, indicating low flows and flows below instream objectives affecting applications for temporary diversion licences.[13] These constraints on available water resources highlight water licensing as a key regulatory consideration in blue hydrogen development in Alberta.

Carbon capture, utilization, storage: Section 57(5) of the MMA grants the Crown ownership of the pore space used for CCUS. Part 9 of the MMA contains regulatory requirements applicable to CCUS, in the form of carbon sequestration, in the province. The legislation enables the minister to enter into agreements for evaluation of subsurface reservoirs to determine suitability for carbon sequestration (evaluation permits),[14] and agreements granting rights to inject captured carbon dioxide into subsurface reservoirs to be sequestered (carbon sequestration leases).[15]

Requirements for evaluation permits and carbon sequestration leases are addressed in the *Carbon Sequestration Tenure Regulation* (Carbon Sequestration Regulation),[16] and include annual rents, monitoring, measurement and verification plans.[17] Applications for carbon sequestration leases must include evidence that the chosen location is suitable for sequestration, and provide a closure plan which meets the prescribed requirements.[18] Before drilling or using a well to sequester carbon dioxide, the lessee must also obtain a well licence and approval under the OGCA.[19]

Securing sufficient water allocation under licences is a key consideration in hydrogen development.

10 *Water Act*, RSA 2000, c. W-3, s. 49(1).
11 *Water Act*, RSA 2000, c. W-3, ss. 51(1), (3) and (4).
12 Alberta Environment, *Approved Water Management Plan for the South Saskatchewan River Basin (Alberta)*, https://open.alberta.ca/publications/0778546209 at ss. 2.1 and 2.7.
13 Alberta Government, *Alberta River Basins*, https://rivers.alberta.ca/.
14 *Mines and Minerals Act*, RSA 2000, c. M-17, s. 115.
15 *Mines and Minerals Act*, RSA 2000, c. M-17, s. 116.
16 *Carbon Sequestration Tenure Regulation*, Alta Reg 68/2011.
17 *Carbon Sequestration Regulation*, ss. 3(2), 6, 7 and 9 (2).
18 *Carbon Sequestration Regulation*, ss. 9 (2)(d) and (f).
19 *Mines and Minerals Act*, RSA 2000, s. 116(2).

Environmental assessment

The requirement for provincial environmental assessment of blue hydrogen projects is likely at the discretion of the director under the EPEA in Alberta. Hydrogen facilities are not listed in the *Environmental Assessment (Mandatory and Exempted Activities) Regulation*, as either mandatory or exempted.[20]

The appropriate regulator

As is sometimes the case with new energy technologies that are not contemplated by existing regimes, blue hydrogen regulation will undoubtedly raise jurisdictional questions pertaining to what regulator is responsible for enforcement of regulatory standards, including those pertaining to environmental assessments and approvals. In Alberta, AEP regulates the enforcement of the EPEA as it applies to oil refineries, power plants, alternative energy plants, petrochemical plants and chemical manufacturing plants, while the AER is responsible for gas plants and bitumen upgraders.[21] It would initially appear that hydrogen, as a gas, would be regulated by the AER. However, as discussed above, existing standalone hydrogen facilities have been regulated exclusively by AEP as chemical manufacturing plants. Given the potential use of hydrogen as an alternative fuel and parallels between chemical and SMR facilities, the regulation of blue hydrogen by AEP may continue to be appropriate.

However, similar to the discussion on lithium technologies in the Lithium section, given the fact that hydrogen technologies make use of conventional natural gas resources (specifically, methane) and that the AER has an existing role in relation to CCUS activities, gas processing and gas pipelines, the AER may be better positioned to provide clear and suitable directions to proponents and a “one-window” regulatory framework that leverages the AER’s existing areas of expertise. Further clarity through regulatory reform will be required to resolve this issue.

British Columbia

Licensing

Licensing requirements attach to water diversion and to CCUS. While the licensing requirements for SMR facilities are presently unclear, a permit may be required under the OGAA. Hydrogen proponents must also consider whether an environmental assessment is required based on applicable legislative thresholds.

20 *Environmental Assessment (Mandatory and Exempted Activities) Regulation*, Alta Reg 111/1993.
21 Alberta Energy Regulator, *Environmental Protection and Enhancement Act*, “What We Regulate Under the Act,” https://www.aer.ca/regulating-development/project-application/application-legislation/environmental-protection-and-enhancement-act.

Facilities: BC's *Hydrogen Study* notes the need for regulation to provide a clear framework for blue and green hydrogen-producing facilities.[22] Under the current framework, blue hydrogen production through SMR could be considered an "oil and gas activity," regulated and subject to permit requirements under the OGAA, particularly where integrated within oil refining facilities.[23] Oil and gas activities under the OGAA include "the production, gathering, processing, storage or disposal of petroleum, natural gas or both."[24] The legislation provides a broad definition of "natural gas" including "all fluid hydrocarbons, before and after processing, that are not defined as petroleum, and includes hydrogen sulphide, carbon dioxide and helium produced from a well."[25] As SMR involves the processing of natural gas to produce hydrogen, it appears to fall under the BC Oil and Gas Commission (BCOGC)'s purview as an oil and gas activity under the OGAA.

A proponent of an oil and gas activity must obtain a permit and must comply with the OGAA and its regulations as well as the terms of the permit.[26] The application process involves notification and consultation requirements in prescribed circumstances,[27] and allows stakeholders to make written submissions regarding the application.[28] Permit application requirements include a description of the activity, plans, application forms and records required by the BCOGC, a written report of consultations and notifications, and may require payment of security.[29] The BCOGC considers the application and any written submissions, as well as the government's environmental objectives,[30] before deciding whether to issue a permit for the oil and gas activity.[31]

Water diversion: As in Alberta, securing sufficient water allocation is a key regulatory consideration for blue hydrogen developments in B.C. The province has its own distinct legislative regime for water licensing and allocation under the WSA. The WSA defines several "purposes" for which water may be diverted, subject to the Act's requirements. Diverting water for use in SMR facilities does not appear to fit neatly within any of the categories established under the WSA. For instance, "oil and gas purpose" is defined as "use of water in the development of petroleum or natural gas wells or the production of petroleum or natural gas resources,"[32]

BC's Hydrogen Study notes the need for regulation to provide a clear framework for blue and green hydrogen-producing facilities.

22 Zen and the Art of Clean Energy Solutions, *British Columbia Hydrogen Study* (June 2019), https://www2.gov.bc.ca/assets/gov/government/ministries-organizations/ministries/zen-bcbn-hydrogen-study-final-v5_noappendices.pdf at PDF 161.
23 For example, Tidewater Midstream and Infrastructure Ltd.'s Prince George Refinery (formerly owned by Husky) produces hydrogen used in its refining process through SMR (see Zen and the Art of Clean Energy Solutions, *British Columbia Hydrogen Study* (June 2019), https://www2.gov.bc.ca/assets/gov/government/ministries-organizations/ministries/zen-bcbn-hydrogen-study-final-v5_noappendices.pdf at PDF 105).
24 *Oil and Gas Activities Act*, SBC 2008, c. 36, s. 1(2).
25 *Oil and Gas Activities Act*, SBC 2008, c. 36, s. 1(1) and *Petroleum and Natural Gas Act*, RSBC 1996, c. 361, s. 1.
26 *Oil and Gas Activities Act*, SBC 2008, c. 36, s. 21.
27 See *Consultation and Notification Regulation*, BC Reg 217/2017
28 *Oil and Gas Activities Act*, SBC 2008, c. 36, s. 22.
29 *Oil and Gas Activities Act*, SBC 2008, c. 36, ss. 24(1) and 30.
30 Prescribed under the *Environmental Protection and Management Regulation*, BC Reg 41/2016.
31 *Oil and Gas Activities Act*, SBC 2008, c. 36, s. 25(1).
32 *Water Sustainability Act*, SBC 2014, c. 15, s. 2.

whereas “industrial purpose” is limited to very specific industrial uses that are enumerated in regulations, the most relevant being the use of water “for the operation of a sawmill, shipyard, factory or other manufacturing facility or for the operation of a wharf, and includes the use of water in a gravel washing plant or the use in an industrial context of water to prevent a fire.”[33] Further clarity on where SMR uses fall within this regime is required.

Regardless, blue hydrogen project proponents will likely require a licence to divert and beneficially use a specified quantity of water under the WSA.[34] The comptroller or water manager may only issue licences to the entities listed under the Act. This list includes “an owner of land or a mine,” a category which many proponents will fall into, as the WSA’s definition of an “owner” includes a person “entitled to possession of the land.” Proponents should note that partnerships, lacking legal personhood, may be precluded from holding a water licence.[35]

In determining whether to grant a licence under the WSA, the comptroller or water manager must consider environmental flow needs, defined as “in relation to a stream … the volume and timing of water flow required for the proper functioning of the aquatic ecosystem of the stream.”[36] Critical environmental flow thresholds take precedence over water allocations. In applying for a licence, applicants must provide any plans, specifications and other information requested by the decision maker,[37] and may be required to have an assessment performed and report prepared by a qualified person specified by the decision maker. Licences may be subject to terms and conditions,[38] and a decision maker may impose mitigation measures where they determine that licensed activities are likely to have significant adverse effects on water quantity.[39] Successfully obtaining a water licence on agreeable terms is an essential regulatory consideration for hydrogen developments in B.C.

Carbon capture, utilization, storage: Pore space in British Columbia is Crown-owned. The *Petroleum and Natural Gas Act* (PNGA) allows the provincial government to designate land for storage, and such land, whether privately or publicly owned, becomes Crown land after 90 days.[40]

B.C.’s PNGA provides a scheme for permitting storage reservoirs and wells which may be used for carbon

33 *Water Sustainability Regulation*, B.C. Reg 36/2016, s. 2 and Schedule A.
34 *Water Sustainability Act*, SBC 2014, c. 15, s. 7(1)(a).
35 *Water Sustainability Act*, SBC 2014, c. 15, s. 9(a). See a discussion of leases to Crown land, the definition of “owner” and entitlement to hold water licenses under the predecessor to the WSA in *Harrison Hydro Project Inc. v. Environmental Appeal Board*, 2017 BCSC 320, affirmed 2018 BCCA 44, application for leave dismissed 2018 CanLII 71038 (SCC). See also *Derrickson v. Kennedy*, 2006 BCCA 356 at para 10.
36 *Water Sustainability Act*, SBC 2014, c. 15, ss. 15 and 1.
37 *Water Sustainability Act*, SBC 2014, c. 15, s. 12(1)(b)
38 *Water Sustainability Act*, SBC 2014, c. 15, s. 14.
39 *Water Sustainability Act*, SBC 2014, c. 15, s. 16.
40 *Petroleum and Natural Gas Act*, RSBC 1996, c. 361, ss. 127-129.

storage. A licence is required to explore for a storage reservoir, in most circumstances.[41] The Act also allows the minister to lease storage reservoirs upon accepting applications.[42] The *Petroleum and Natural Gas Storage Reservoir Regulation* prescribes an annual rent per hectare for reservoir leases.[43]

In addition, the use of a storage reservoir is an "oil and gas activity,"[44] and is therefore subject to permitting requirements under the OGAA, as described above in relation to blue hydrogen SMR facilities.

Environmental assessment

B.C. environmental assessment processes apply to projects that are described in the regulation, that meet effects thresholds, or that are designated as reviewable by the minister under section 11 of the BCEAA.

Like Saskatchewan and Alberta's respective regimes, the BCEAA does not explicitly require or exempt hydrogen developments from environmental assessment. However, any blue hydrogen projects that trigger effects thresholds under B.C.'s environmental assessment regime will likely require an environmental assessment. For instance, chemical manufacturing facilities producing 100,000 tonnes or more per year meet the threshold for environmental assessment,[45] as do water diversion projects diverting water at a rate exceeding 10 million cubic metres of water per year or groundwater exceeding a rate of 75 litres per second.[46] Regardless, there remains some risk that SMR facilities and associated components will be subject to provincial environmental assessment requirements by virtue of ad hoc designation powers under the Act.

Like Saskatchewan and Alberta's respective regimes, the BCEAA does not explicitly require or exempt hydrogen developments from environmental assessment.

Saskatchewan

Licensing

Key licensing considerations in Saskatchewan include water licences and uncertainty regarding the need to license facilities associated with blue hydrogen development. CCUS, which is occurring in Saskatchewan, is permitted pursuant to an established legislative regime.

Facilities: Licensing requirements for SMR facilities are presently unclear under the Saskatchewan regime, and should be addressed explicitly to facilitate blue hydrogen development.

Under the existing framework, blue hydrogen may constitute a "product" as defined in the SKOGCA, which

41 *Petroleum and Natural Gas Act*, RSBC 1996, c. 361, s. 126(1).
42 *Petroleum and Natural Gas Act*, RSBC 1996, c. 361, s. 130.
43 *Petroleum and Natural Gas Storage Reservoir Regulation*, BC Reg 269/2010, s. 7.
44 *Oil and Gas Activities Act*, SBC 2008, c. 36, s. 1(2).
45 *Reviewable Projects Regulation, BC Reg 243/2019, s 3(1) and Table 1.*
46 *Reviewable Projects Regulation, BC Reg 243/2019, s 3(1) and Table 9.*

includes commodities "made from oil or gas and includes … by-products derived from oil or gas."[47] Similarly, a blue hydrogen SMR facility may be considered a "facility" under the SKOGCA,[48] in which case a licence, or exemption, must be obtained pursuant to section 8.01. Facility licence eligibility criteria are established in the *Oil and Gas Conservation Regulations* (SKOGCR) and require that the licence holder have an ownership interest in the facility.[49]

The Saskatchewan government has published a directive establishing requirements for facility licences.[50] The Licence Directive lists those facilities that require a licence and those that are exempt. However, the Licence Directive does not address hydrogen facilities, leaving open the question as to whether SMR operations must be licensed as analogous to "Gas Processing Plants," or whether they are exempt from licensing as part of "midstream and downstream facilities and sites."[51] This lack of clarity should be addressed to better enable hydrogen development.

Water diversion: The WSAA imposes licensing requirements for water allocations and also requires approval for construction and operation of works that divert water.[52] Applicants for a water rights licence and approval to construct and operate works must be owners or have a legal interest in the land the works will be constructed on. Leasing the land is sufficient to meet this requirement.[53] Applicants must provide a description of the proposed works, a legal description of the land, the applicant's interest in the land, and a detailed description of the source, volume and method of diverting water.[54]

The Water Security Agency (Agency) may issue water rights licences for any term and subject to any terms and conditions that the Agency deems appropriate.[55] As with licences, approvals to construct may also be subject to whatever terms and conditions the Agency deems appropriate. The Agency is also obliged to publish notices of applications for diversion works, triggering a public comment process, and, if it is of the view that the proposed works "may impair the environment or have an impact on natural resources," it may forward the application to the minister responsible for *The Environmental Management and Protection Act,*

47 *The Oil and Gas Conservation Act*, RSS 1978, c. O-2, s. 2(1)(n).
48 *Oil and Gas Conservation Regulations*, RRS 2012, c. O-2 Reg 6, s. 2(1)(m).
49 *Oil and Gas Conservation Regulations*, RRS 2012, c. O-2 Reg 6, ss. 12 and 2(1)(yy).
50 Saskatchewan, *Directive PNG001: Facility License Requirements*, *Revision 1.1* (June 2020) ["Licence Directive"].
51 License Directive at PDF 5 and 6.
52 *The Water Security Agency Act*, SS 2005, c. W-8.1, ss. 50 and 59-62.
53 See Water Security Agency, *Instructions to Complete Application for Water Rights Licence and Approval to Construct and Operate Works under The Water Security Agency Act* (revised 22 January 2019), https://www.wsask.ca/Permits-and-Approvals/Start-Here/#using%20water at 1.
54 Water Security Agency, *Instructions to Complete Application for Water Rights Licence and Approval to Construct and Operate Works under The Water Security Agency Act* (revised 22 January 2019), https://www.wsask.ca/Permits-and-Approvals/Start-Here/#using%20water at 1-2.
55 *The Water Security Agency Act*, SS 2005, c. W-8.1, s. 50(2).

2010.[56] If he or she believes the withdrawals create "an enhanced risk of an adverse effect occurring", the minister can require the proponent to obtain an environmental permit.[57]

In evaluating applications for surface or groundwater allocations (including licences and approvals for diversion works), the Agency considers scarcity of the water supply at the point of diversion, including during drought conditions, purpose of the water use, quality of the source water and impacts to adjacent water users, the watershed and future water management. The Agency will also consider, where necessary, mitigation measures or operating conditions to manage or prevent impacts.[58]

As in other jurisdictions, obtaining sufficient water allocation is an important consideration for hydrogen projects in Saskatchewan.

Carbon storage: In Saskatchewan, the Crown owns all pore spaces that were once occupied by Crown minerals.[59] Ownership of pore spaces on freehold lands in Saskatchewan is not prescribed by legislation and is less clear. Common law suggests that, at least where pore space is not associated with mineral extraction, title belongs to the surface owner.

Ownership of pore spaces on freehold lands in Saskatchewan is not prescribed by legislation and is less clear.

CCUS falls within the licensing regime established by the SKOGCA. The Act regulates any "waste processing facility," which means "any facility that is constructed and operated for the purpose of containing, storing, handling, treating, processing, recovering, reusing, recycling, destroying or disposing of oil and gas waste." [60] Safe storage of substances injected into subsurface formations is one of the SKOGCA's stated purposes.[61] The SKOGCR exempts caverns for gas storage (not including wells or surface infrastructure) from facility licensing requirements.[62]

Environmental assessment

The SEAA makes any "development" subject to approval.[63] The SEAA defines "development" as including any project, operation or activity which is likely to "substantially utilize any provincial resource and in so doing pre-empt the use, or potential use, of that resource for any other purpose" or "involve a new technology that is

56 *The Water Security Agency Act*, SS 2005, c. W-8.1, s. 61.
57 *The Environmental Management and Protection Act, 2010*, SS 2010, c. E-10.22, s. 26(1).
58 Saskatchewan Water Security Agency, *Permits and Approvals: Water Allocation*, https://www.wsask.ca/Permits-and-Approvals/Water-Allocation/.
59 *The Crown Minerals Act*, RSS 1984 c-50.2, s. 27.2.
60 *Oil and Gas Conservation Regulations*, RRS 2012, c. O-2 Reg 6, s. 2(1)(vv).
61 *The Oil and Gas Conservation Act*, RSS 1978, c. O-2, s. 3(1)(g).
62 *Oil and Gas Conservation Regulations*, RRS 2012, c. O-2 Reg 6, s. 15(d).
63 *The Environmental Assessment Act*, SS 1979-80, c. E-10.1, s. 15.

concerned with resource utilization and that may induce significant environmental change."[64] The water-intensive nature of blue hydrogen production may trigger the need for an environmental assessment under the SEAA.

Proponents may apply for a determination regarding whether their project is a development subject to environmental assessment requirements in Saskatchewan, as described in the Lithium section.[65]

A path forward

Government policies

While a cohesive regulatory framework for hydrogen production is yet to be established in any of the Western Canadian provinces addressed herein, governments are currently under pressure to incentivize the development of hydrogen production. For instance, the Government of Canada recently announced a memorandum of understanding with Germany that commits both countries to collaborating more closely on clean energy innovation and trade, including an emphasis on hydrogen production as a low carbon fuel.[66] Both the Alberta and federal governments have published hydrogen strategies aimed at increasing hydrogen production through government support.[67] Goals of these strategies include passing legislation and enacting regulations, policy and specific standards to enable and support the development of hydrogen technologies. In B.C., there is no similar hydrogen strategy; however, a recent study commissioned by the B.C. government on hydrogen technology found that hydrogen plays an important role in B.C.'s plan to reduce greenhouse gas emissions.[68]

These policy developments suggest that hydrogen proponents in Western Canada will eventually be supported by regulations that facilitate the development of hydrogen production facilities and associated technologies, as well as the use of hydrogen energy for various purposes. It is likely that, in the near term, we will see more specific regulation and policy applicable to hydrogen production and supporting technology.

64 *The Environmental Assessment Act*, SS 1979-80, c. E-10.1, s. 2(e).
65 See *The Environmental Assessment Act*, SS 1979-80, c. E-10.1, s. 7.2.
66 Government of Canada, *Canada Strengthens Energy Partnership with Germany* (March 16, 2021), https://www.canada.ca/en/natural-resources-canada/news/2021/03/canada-strengthens-energy-partnership-with-germany.html
67 Government of Alberta, Natural Gas Vision and Strategy, https://www.alberta.ca/natural-gas-vision-and-strategy.aspx; Natural Resources Canada, *Hydrogen Strategy for Canada*, https://www.nrcan.gc.ca/climate-change/the-hydrogen-strategy/23080; see also Paula Olexiuk et al, December 2020, *Federal Government Announces Canada's Hydrogen Strategy*, https://www.osler.com/en/resources/regulations/2020/federal-government-announces-canada-s-hydrogen-strategy.
68 Zen and the Art of Clean Energy Solutions, *British Columbia Hydrogen Study* (June 2019), https://www2.gov.bc.ca/assets/gov/government/ministries-organizations/ministries/zen-bcbn-hydrogen-study-final-v5_noappendices.pdf at PDF 26.

Incentivizing hydrogen development

Clean fuel standards may incentivize oil and gas producers to invest in hydrogen production. Currently, fuel producers can receive credits for producing less carbon intensive fuels. The clean fuel standards are designed for more traditional conceptions of alternate fuel, such as diesels and ethanol, as they provide credits to fuel producers for including more environmentally friendly blends in gasoline fuel production. A possible way to utilize this existing framework is to expand the availability of renewable fuel credits to oil and gas producers who leverage their resources to make hydrogen.

For example, in Alberta, the *Petrochemicals Diversification Program Royalty Credit Regulation* allows for producers to receive royalty credits for methane, ethane or propane production.[69] The royalty credits can then be used to offset the royalty payments that are owing to the Crown.[70] While this regime is specifically for methane, ethane and propane, there is a close relationship between the goals of the program, the products it covers and hydrogen production such that extending the regulation to cover hydrogen production would be logical and further promote diversification of the energy market.

Hydrogen projects located in Alberta are also eligible for capital grants under Alberta's Petrochemical Incentive Program, provided they meet minimum investment and job-creation requirements.[71] This program provides a significant capital grant once the facility is operating.

In B.C., hydrogen is a renewable fuel pursuant to the *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act* (GGRA).[72] This definition is likely to have positive implications for incentivizing hydrogen manufacturers in B.C.

The Saskatchewan Petroleum Innovation Incentive (SPII) offers transferable royalty credits for eligible innovative projects at a rate of 25% of the project's costs. Notably, qualifying innovations must be the first of their kind in Saskatchewan.[73] Blue hydrogen developments in Saskatchewan may also be eligible for transferable royalty tax credits at 15% of project costs through the Oil and Gas Processing Investment Incentive (OGPII). The OGPII may be available for existing facility expansions as well as for new facilities.[74]

69 *Petrochemicals Diversification Program Royalty Credit Regulation*, Alta Reg 54/2016, s. 2.
70 *Petrochemicals Diversification Program Royalty Credit Regulation*, Alta Reg 54/2016, s. 6.
71 Alberta Energy, *The Alberta Petrochemicals Incentive Program: Program Guideline Document*, https://open.alberta.ca/dataset/ba855f49-bb70-470a-8d9e-6c850eec5c5a/resource/a765a45f-acbc-4952-bc9e-b276eafd2190/download/energy-alberta-petrochemicals-incentive-program-program-guideline-document-2020.pdf at 5 -6.
72 *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act*, SBC 2008, c. 16, s.1.
73 Saskatchewan, *Saskatchewan Petroleum Innovation Incentive (SPII)*, https://www.saskatchewan.ca/business/agriculture-natural-resources-and-industry/oil-and-gas/oil-and-gas-incentives-crown-royalties-and-taxes/saskatchewan-petroleum-innovation-incentive#eligibility.
74 Saskatchewan, *Oil and Gas Investment Incentive*, https://www.saskatchewan.ca/business/agriculture-natural-resources-and-industry/oil-and-gas/oil-and-gas-incentives-crown-royalties-and-taxes/oil-and-gas-processing-investment-incentive#benefits.

Proponents may also leverage existing carbon offset frameworks to receive carbon offset credits for the development of blue hydrogen technologies. Both B.C. and Alberta have regulations that provide for proponents to receive credits for the amount in which their projects offset and reduce greenhouse gas emissions.

In B.C., the *Greenhouse Gas Emission Control Regulation*,[75] sets out the requirements each proponent is to meet. Most notably, proponents are to submit a project plan to a validation body (as defined by the regulation) that states how the project will reduce greenhouse gas emissions. Furthermore, pursuant to the GGRA, hydrogen manufactured for use in place of petroleum diesel is considered a renewable fuel and therefore fits neatly into the carbon offset framework.[76]

In Alberta, emission offset projects must meet requirements established under the *Technology Innovation and Emissions Reduction Regulation*[77] (TIER), as well the Standard for Greenhouse Gas Emission Offset Project Developers, created under the TIER, and an approved quantification protocol. While Alberta has an approved quantification protocol in place for CCUS, there is no protocol for hydrogen development or the SMR process. Considerations of how the SMR and CCUS activities are linked may play into how offsets are calculated for blue hydrogen projects, and further clarity regarding how SMR facilities may fit in the TIER framework is required. As in B.C., the Alberta regime requires developers to submit project plans which describe how the project meets offset requirements.[78]

Both B.C. and Alberta have regulations that provide for proponents to receive credits for the amount in which their projects offset and reduce greenhouse gas emissions.

75 *Greenhouse Gas Emission Control Regulation*, BC Reg 250/2015.
76 *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act*, SBC 2008, c. 16, s.1.
77 *Technology Innovation and Emissions Reduction Regulation*, Alta Reg 133/2019
78 Paula Olexiuk et al., *The More Things Change the More they Stay the Same: Alberta Revamps Carbon Pricing Regime for Large Emitters*, 26 November 2019, available at: https://www.osler.com/en/resources/regulations/2019/the-more-things-change-the-more-they-stay-the-same-alberta-revamps-carbon-pricing-regime-for-large.

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