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Energy: Oil & Gas

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Sean Korney, Carolyn Wright,
Evan Dixon and Brendan Downey
Burnet, Duckworth & Palmer LLP

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Law and Practice

Contributed by:
Sean Korney, Carolyn Wright, Evan Dixon and Brendan Downey
Burnet, Duckworth & Palmer LLP ***see p.17***

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1.1 System of Petroleum Ownership

General

Canada is a federal state comprised of a federal government, ten provincial governments and three territorial governments. Both the federal government and the provincial and territorial governments have the jurisdiction to make laws (generally referred to as Acts) and other subsidiary legislation (generally referred to as Regulations). Under this system, there is both state (Crown) and private (freehold) ownership of petroleum. In addition, the ownership of petroleum in situ may be split by formation and by substance.

Canada operates on a "tax and royalty" system and not on a "production sharing contract" system. Within this tax and royalty system, there is broad freedom to contract, and detailed laws and regulations accompany the development of petroleum.

Western Canada (primarily Alberta, but also British Columbia and Saskatchewan) currently accounts for approximately 95% of Canadian petroleum production. For this reason and due to editorial limits, our answers focus mostly on the petroleum industry in Alberta and applicable federal laws.

Crown

Under the Canadian Constitution, title to the petroleum located in most of Canada's offshore and federally administered onshore lands, including First Nations' reserve lands, vests in the federal Crown. As an exception to the general rule of federal ownership of petroleum on First Nations' reserve lands, some First Nations that have formally settled land claims with the federal government own the petroleum on their lands.

Ownership of petroleum in all other Crown lands vests in the various provincial governments.

Freehold

Freehold petroleum ownership exists where the outright ownership of mines and mineral rights was historically granted to private persons by the federal Crown.

1.2 Regulatory Bodies

Sections 91 and 92 of the Canadian Constitution allocate a number of "heads of power" that are relevant to petroleum development between the federal and provincial governments. The federal government has jurisdiction over petroleum on federal lands, and over matters that are inter-provincial or international in nature, such as some pipelines and exports. Each provincial government has jurisdiction over the petroleum and related works or undertakings within its borders that do not otherwise fall under federal jurisdiction. The federal and provincial governments share responsibility for environmental protection and the environmental assessment of certain petroleum projects.

As an exception to this division of power, the federal government and each of the provinces of Nova Scotia and Newfoundland & Labrador have an agreement to jointly administer and regulate offshore petroleum development.

Federal and Offshore

In August 2019, the Canada Energy Regulator (CER) replaced the National Energy Board and assumed responsibility for regulating petroleum projects within federal jurisdiction, including certain offshore projects; interprovincial, international and offshore pipelines; and the issuance of orders and licences for the export of petroleum from Canada.

Indian Oil and Gas Canada (IOGC) administers the issuance of petroleum rights on behalf of the federal government on First Nations' reserve lands. Its governing legislation is the Indian Oil and Gas Act. Typically, the development of petroleum on First Nations' reserve lands is conducted in accordance with the laws of the province in which the reserve lands are located.

The Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) and the Canada-Newfoundland & Labrador Offshore Petroleum Board (CNLOPB) share regulatory authority with the CER over their respective offshore areas. The CNSOPB is governed by the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act and the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation (Nova Scotia Act) Act (the Nova Scotia Accord Acts), while the CNLOPB is governed by the Canada-Newfoundland and Labrador Atlantic Accord Implementation Act and the Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act (the Newfoundland Accord Acts).

Provinces

In Alberta, the Ministry of Energy administers Crown petroleum resources, though it has delegated many of its responsibilities to the Alberta Energy Regulator (AER) under the Responsible Energy Development Act (REDA). The AER is a "single window" agency that is responsible for regulating the petroleum industry in Alberta and conducts environmental assessments associated with petroleum activities. Gas utility pipelines are regulated by the Alberta Utilities Commission.

In British Columbia, the Ministry of Energy and Mines administers Crown petroleum resources, though it has delegated many of its responsibilities to the British Columbia Oil and Gas Commission (BCOGC) under the Oil and Gas Activities Act. Under the Utilities Commission Act, the British Columbia

Utilities Commission (BCUC) has some regulatory authority over intra-provincial pipelines.

Saskatchewan has not delegated regulatory authority to an administrative agency; petroleum development is instead regulated by its Ministry of Energy and Resources under The Energy and Mines Act.

1.3 National Oil or Gas Company

There is no Canadian "National Oil Company" (NOC) as that term is generally understood. However, the federal government has ownership interests in certain companies, such as Trans Mountain Corporation and the Canada Hibernia Holding Corporation. In addition, the Alberta government has made investments in the Keystone XL pipeline project and the Coastal GasLink Pipeline Limited Partnership.

1.4 Principal Petroleum Law(s) and Regulations

Federal and Offshore

The Canada Petroleum Resources Act governs the allocation and administration of production royalties and rights to explore for and develop petroleum on federal lands.

The Canada Oil and Gas Operations Act governs the exploration, production, processing and transportation of offshore petroleum throughout offshore marine areas controlled by the federal government.

Together with the Indian Oil and Gas Regulations, the Indian Oil and Gas Act creates the regulatory framework for petroleum exploration and development on First Nations' reserve lands.

The Nova Scotia Accord Acts and Newfoundland Accord Acts implement the agreements between the federal government and each of the Nova Scotia and Newfoundland & Labrador provincial governments concerning the shared management of offshore petroleum.

The Canadian Energy Regulator Act (CERA) establishes the regulatory framework governing the CER and provides for interprovincial and international pipelines, petroleum export, and certain offshore projects.

Provinces

The Mines and Minerals Act governs Crown petroleum leases and Crown production royalties in Alberta.

The Oil and Gas Conservation Act (OGCA) governs petroleum exploration, development, production, processing and abandonment activities in Alberta.

The Oil Sands Conservation Act (OSCA) governs the exploration, development, production, processing and abandonment of activities undertaken in connection with Alberta's oil sands.

The Orphan Fund Delegated Administration Regulation delegates certain responsibilities to the Orphan Well Association (OWA), an industry-funded association intended to oversee the decommissioning of "orphan" petroleum facilities left behind by insolvent, bankrupt and defunct petroleum companies.

The Gas Resources Preservation Act requires persons seeking to export natural gas from Alberta to first obtain an export permit.

The Pipeline Act governs the construction, operation and abandonment of provincially regulated pipelines in Alberta.

The Environmental Protection and Enhancement Act is the main piece of environmental protection legislation in Alberta.

The Surface Rights Act governs surface rights in Alberta and creates the Surface Rights Board to adjudicate disputes between freehold surface owners and companies wishing to conduct petroleum operations.

In British Columbia, the material legislation includes the Petroleum and Natural Gas Act, the Oil and Gas Activities Act, the Dormancy and Shutdown Regulation, the Pipeline Regulation, the Environmental Management Act, the Environmental Assessment Act and the Surface Lease Regulation.

In Saskatchewan, the material legislation includes The Crown Minerals Act; The Mineral Resources Act; The Oil and Gas Conservation Act; The Pipelines Act, 1998; The Environmental Management and Protection Act; and The Surface Rights Acquisition and Compensation Regulations.

2. Private Investment in Petroleum: Upstream

2.1 Forms of Allowed Private Investment in Upstream Interests

To facilitate petroleum development, the resource owners (both Crown and freehold) typically issue rights to investors to explore for and, if found, develop, produce and take petroleum. This "right to capture" is typically granted under a petroleum lease, which is considered a profit à prendre and is an interest in land.

Crown

For onshore Crown lands, an investor must obtain a lease or licence from the appropriate Crown authority. Although there are differences, unless the context requires greater specificity, we will generally refer to Crown leases and licences collectively as "Crown leases". Crown leases allow investors to explore for, develop and produce the granted petroleum substances from the granted formations, subject to the payment of annual rentals and production royalties.

The terms that govern onshore Crown leases are prescribed by law and are non-negotiable. There is some sovereign risk that the Crown could change the terms of the Crown leases through legislative action.

Onshore Crown leases may be subject to reversionary programmes intended to encourage exploration by requiring that unproductive stratigraphic formations (deeper and/or shallower than the productive formations) revert to the Crown. This is analogous to relinquishment under a production sharing contract, but by formation, not surface area.

For offshore Crown lands, the CNSOPB and CNLOPB each issue and administer rights to explore for and produce petroleum in their respective offshore areas on Canada's east coast. In all other offshore areas, the federal government has jurisdiction, although there is a moratorium on offshore petroleum development on Canada's west coast and in the Arctic.

Freehold

Though freehold leases may be negotiated to reflect whatever terms the freehold lessor and producer lessee agree, the Canadian Association of Petroleum Landmen (CAPL) has developed a commonly used form of freehold lease. The CAPL form improves efficiency and certainty through standardisation and seeks to address problems caused by certain terms in historical forms and other bespoke lease agreements that led to unintended early termination. Care should be taken if an investor encounters unique forms of freehold lease, especially if the lease is older, as they frequently contain such terms.

Operating Permits

There is an important distinction between an investor's interest in petroleum rights (eg, the Crown lease or freehold lease) and the investor's right to conduct operations in respect of those rights. After an investor has obtained a Crown or freehold lease, it must obtain all required regulatory operating permits from the appropriate regulatory authorities before commencing field operations. Generally, only the operator (not the non-operating partners) is required to obtain and maintain the necessary operating permits.

In western Canada, the AER, the BCOGC and the Saskatchewan Ministry of Energy and Resources each have eligibility requirements for permit-holders, including residency, financial capacity and insurance. In Alberta, the AER's "Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals" gives the AER the ability to require additional information regarding an investor's corporate structure and financial health, compliance history, and the corporate history of its directors, officers and shareholders, and to assess such information for adequacy. A Government of Alberta statement on 30 July 2020 (the July Statement) indicated additional changes are forthcoming to the "capability assessment system" for permit-holders.

Surface Lands

It is not uncommon for the owner of the surface lands to be different from the owner of the underlying petroleum rights. Where the surface ownership and petroleum ownership is split (eg, where a farmer owns the surface lands but the Crown owns the petroleum), petroleum ownership is the dominant tenement – the surface owner can be compelled (for reasonable compensation) to grant the petroleum owner (or its lessee) access to surface lands necessary to develop the petroleum resource.

An investor must secure the necessary surface rights before it can commence field operations.

2.2 Issuing Upstream Licences/Obtaining Petroleum Rights

Crown

Onshore Crown leases are generally obtained through a transparent government-administered auction process. In Alberta, for example, prospective investors submit requests to Alberta Energy for parcels of land designated by the investor to be included in the land sale. Following a round of bids, the investor with the highest bid for a parcel will almost always be awarded the leasehold rights for that parcel. Alberta Energy administers a separate, though similar, auction process for oil sands leases and permits.

Similar to onshore rights, licences for offshore exploration and development activities in areas administered by the CNSOPB and the CNLOPB are issued through public bidding processes. Successful bidders must satisfy significant financial assurance or security requirements.

For federally administered First Nations reserve lands, investors may obtain a petroleum lease from IOGC through public tender or direct negotiations with the First Nation; however, both the Minister of Indigenous Services and the band council of the First Nation must approve the terms of the lease.

Freehold

Freehold leases are obtained directly from the petroleum owner through direct negotiations.

2.3 Typical Fiscal Terms Under Upstream Licences/Leases

Crown Leases – General

Crown leases are subject to production royalties prescribed by legislation and regulation. The royalty rates depend on prescribed reference prices, well productivity, geographic location, field discovery date, method of recovery and the type or quality of the petroleum substance produced. In addition, a Crown lease-holder will generally have to pay annual rentals calculated on an area basis.

Alberta Crown leases

Royalties payable on petroleum produced from wells drilled prior to 31 December 2016 range from 0% to 40% for oil, and from 5% to 36% for natural gas. For wells drilled on or after 1 January 2017, producers pay a flat royalty rate of 5% of gross revenue until the well reaches payout. After payout, producers pay an increased royalty on revenues of between 5% and 40% for oil, and between 5% and 36% for natural gas. Once production in a mature well drops below a certain rate of production, the royalty rate is reduced.

Oil sands production in Alberta is subject to a different royalty regime. Prior to payout of an oil sands project, a "gross revenue royalty" is paid at a rate that ranges between 1% and 9% depending on the average monthly West Texas Intermediate price. After payout, the royalty is the greater of: (i) the gross revenue royalty; or (ii) a net revenue royalty based on rates that vary in accordance with prescribed benchmark WTI prices.

British Columbia Crown leases

Royalty rates in British Columbia vary based on a number of factors, including the characteristics of the produced petroleum substances and the productivity of the wells. Royalties can be as high as 40% for oil and 27% for natural gas.

Saskatchewan Crown leases

In Saskatchewan, a "Resource Surcharge" and Crown royalties as high as 45% apply to petroleum production. The Resource Surcharge rate is 3% of the proceeds from the sale of all petroleum produced from wells drilled before 1 October 2002 and 1.7% of the proceeds from wells drilled after 30 September 2002.

Newfoundland & Labrador and Nova Scotia offshore Crown leases

Newfoundland & Labrador introduced a generic royalty scheme in 2015 for new offshore oil projects, wherein a basic royalty calculated on gross revenue minus transportation costs becomes payable when a project starts producing oil, increasing from 1% to 7.5% as the project recovers its costs. Upon cost recovery, an additional royalty of 10% to 50% will apply to net revenues. The basic royalty is credited against the net royalty. The royalty regime for offshore natural gas production is comprised of a basic royalty calculated as a function of netback price and gross revenue less transportation. The basic royalty rate ranges from 2% to 10%, depending on netback prices. Once cost recovery occurs, an additional royalty of 0%-50% on net revenues will apply.

Nova Scotia has a generic royalty programme that is similar to Newfoundland & Labrador's, although there are some important differences, such as royalty rates.

Freehold Leases

Royalties payable on petroleum produced from freehold lands are determined by negotiation and documented in the freehold lease. Certain provincial taxes and other charges apply to freehold production in British Columbia, Alberta and Saskatchewan.

Subordinate Royalty Interests

Crown lessees and freehold lessors and lessees may create additional royalty interests or net profits interests which, depending on their construction, may be either contractual interests or interests in land.

2.4 Income or Profits Tax Regime Applicable to Upstream Operations

While taxes in Canada are levied at the federal, provincial and municipal levels, the federal government has the most comprehensive taxation powers, administering its authority under the Income Tax Act (ITA) and the Excise Tax Act (ETA). Both the federal and provincial governments have the authority to impose income and sales (value added) taxes and, as a result, there are different sales taxes and marginal income tax rates in each province.

Income Taxes and Deductions from Income

Canada's tax system works on a residency principle: persons that are resident in Canada are taxed on their worldwide income, subject to any applicable tax treaties. Non-resident persons may be taxed in Canada on a number of sources of income, including business income if the non-resident carries on business through a permanent establishment located in Canada, and capital gains that arise from a disposition of "taxable Canadian property"; withholding taxes are imposed on the payment of dividends, interest, royalties and certain other repatriation payments to a non-resident person, the rate of which may be reduced if a tax treaty applies. "Person" is a defined term in the ITA and includes corporations and trusts, but generally does not include partnerships. Thus, while a partnership may not be taxed directly, its partners will be.

Income tax rates are progressive and may change depending on policy initiatives at the federal and provincial levels. After accounting for federal tax abatement and other generally available tax reductions, the net general federal corporate income tax rate is currently 15%. Provincial income tax rates vary between provinces, but the general corporate tax rates fall within the range of 10%-16%. As part of a stimulus package intended to address the economic impacts of the COVID-19 pandemic, the Alberta government announced that, effective from 1 July 2020, it would lower the provincial corporate income tax rate to 8%. If a non-resident corporation does not pay provincial income tax, a higher rate of federal income tax will apply.

Various expenses can be deducted from income for tax purposes that are relevant to Canada's petroleum industry, including:

- the Canadian Exploration Expense;
- the Canadian Development Expense;
- Canadian Oil and Gas Property Expenses;
- Crown royalty payments; and
- capital cost allowances related to the acquisition or disposition of certain depreciable tangible properties acquired or disposed of as part of the business of petroleum exploration.

Sales Taxes

Under the ETA, the federal government levies a 5% goods and services tax (GST) that generally applies to the supply of goods and services in Canada. Alberta does not currently charge a sales tax, and British Columbia and Saskatchewan administer provincial sales taxes (PST) of 7% and 6%, respectively. In Nova Scotia and Newfoundland & Labrador, the federal and provincial governments have created harmonised sales taxes that account for both GST and PST at a combined rate of 15%. The sales tax regime is generally designed to impose sales tax on the final consumer of a good or service, like a value-added tax.

2.5 National Oil or Gas Companies

There is no NOC in Canada; please see **1.3 National Oil or Gas Company**.

2.6 Local Content Requirements Applicable to Upstream Operations

There are no local content requirements per se for onshore petroleum operations, but there are a number of regulations with which investors must comply in order to be eligible to hold petroleum rights and be a qualified operating permit-holder; please see **2.1 Forms of Allowed Private Investment in Upstream Interests**.

Offshore petroleum activities in Nova Scotia and Newfoundland & Labrador have some local content requirements. These include research and development expenditure obligations in the province and local training and education programmes related to offshore petroleum activities.

In addition, foreign investors seeking to acquire petroleum assets of significant value may require federal approval under the Investment Canada Act (the ICA); please see **4.1 Foreign Investment Rules Applicable to Investments in Petroleum**.

2.7 Requirements for a Licence/Lease-Holder to Proceed to Development and Production

Given that Canadian governments do not typically participate directly in petroleum projects, there is usually no government approval right in respect of work plans and budgets, commerciality or development plans. Instead, leases are generally continued by production, and investors operate subject to applicable regulatory regimes.

Onshore Crown Leases and Licences

An Alberta Crown lease or licence typically entitles the investor to explore for and/or develop non-oil sands resources for a prescribed primary term of two to five years, depending on the nature of the instrument. A Crown licence will continue into a five-year intermediate term if the licence-holder has drilled a well on the licence. Licences continued in this manner will carry the same terms as Crown leases, which typically have five-year primary terms. If a Crown lease or licence is validated before the expiry of the applicable term, it will generally continue for as long as there is production from the leased lands. A Crown licence-holder or lease-holder can validate the instrument by, among other things, showing that the petroleum subject to the agreement is capable of production.

Oil sands permits and leases have primary terms of five and 15 years, respectively. Both are subject to conversion or continuation by, among other things, demonstrating that the permit or lease is capable of production. Proceeding to the development phase of oil sands resources requires stakeholder engagement and regulatory approval, which may engage both provincial and federal regulatory processes.

In June 2020, the government of Alberta introduced a number of changes to its oil sands tenure regulations that will come into force on 1 December 2020. Following the commencement of the Oil Sands Tenure Regulations, 2020, the Alberta government will no longer (i) issue permits, or (ii) require that an existing permittee or lessee evaluate the lands subject to the permit or lease as a condition of converting a permit into a primary lease or continuing a primary lease. Instead, a permittee or lessee will simply need to apply to the Minister for the conversion or continuation of the applicable instrument. In addition, when a lease is continued beyond its 15-year primary term, the Minister may designate it to be either producing or non-producing. If a continued lease is designated to be non-producing, the lessee is liable to pay an escalating rental.

The process of obtaining a permit, licence or lease and proceeding to production is somewhat similar in British Columbia and Saskatchewan, though there are some differences regarding application requirements, validation, continuation and term.

Offshore Crown Leases

In offshore areas administered by the CNSOPB or the CNLOPB, exploration and production activities are carried out under different licence types, each of which have separate requirements. Under an exploration licence, an investor may explore for petroleum, but may not conduct offshore development activities. Additionally, activities planned to be carried out in the licence area – such as conducting seismic or exploratory drilling operations – require separate authorisations. If a significant discovery is proved, the investor may apply for a significant discovery licence. These licences do not expire and are intended to preserve the investor's rights during the period between discovery and production. If the holder of an exploration or significant discovery licence can demonstrate that an explored area contains a petroleum discovery that is sufficient to justify capital investment and commercial production, they can apply for a production licence. Production licences have 25-year terms, but may be extended.

Freehold Leases

Freehold leases are typically continued by production achieved during the primary term or, in some cases, payments in lieu of production.

2.8 Other Key Terms of Each Type of Upstream Licence

Please see **2.1 Forms of Allowed Private Investment in Upstream Interests**, **2.2 Issuing Upstream Licences/Obtaining Petroleum Rights**, **2.3 Typical Fiscal Terms Under Upstream Licences/Leases** and **2.7 Requirements for a Licence/Lease-Holder to Proceed to Development and Production**, and **1. General Structure of Petroleum Ownership and Regulation**, **3. Private Investment in Petroleum: Midstream/Downstream** and **5. Environmental, Health and Safety (EHS)** more generally.

2.9 Requirements for Transfers of Interest in Upstream Licences

Onshore Crown and Freehold

For the most part, there are no restrictions on an investor's ability to transfer onshore petroleum assets, provided that the transferee or the successor investor is eligible to receive and own the asset under the applicable laws, regulations and the terms of the project agreements that apply to the petroleum interests. Freehold petroleum leases, operating agreements and other project agreements commonly include consent rights and other contractual restrictions, such as rights of first offer or first refusal, which may be triggered by a transaction. In a low commodity price environment, contractual counterparties are exercising greater scrutiny before consenting to transfers and recognising new counterparties.

While the transfer of onshore petroleum assets may be relatively unrestricted, the transfer of operating permits for the wells, facilities and pipelines that comprise those assets is subject to heightened regulatory scrutiny. The proposed transferee of the operating permits must be eligible to receive and hold the operating permits, and must meet the financial capacity requirements of the regulator. In Canada, investors have joint and several liability to the regulators for certain liabilities associated with petroleum assets. This means that, while the regulators will typically look first to the operator/permit-holder to discharge the decommissioning obligations attached to petroleum assets, they may also look to the non-operators. If an operator incurs costs in respect of its decommissioning obligations, it will generally rely on contractual rights to cause the non-operators to fund their proportionate share.

The AER, the BCOGC and the Saskatchewan Ministry of Energy and Resources each administer their own liability management programme intended to ensure that transferees of operating permits have the financial capacity to meet the decommissioning obligations for the assets that are the subject of the operating permits. If, in the regulator's view, the transferee does not satisfy the requirements of the applicable liability management programme, it can refuse the transfer. Typically, there are no transfer fees in respect of operating permits, but the regulator may require a security deposit from the transferee (or transferor) where it has concerns regarding financial capacity. The July Statement also indicates that changes will be made to the system in Alberta to provide for a more comprehensive and accurate corporate health assessment that will consider a wider variety of assessment parameters than the current system.

It is critical to ensure that any transfer of operating permits will be approved by the applicable regulator. If there is a split in the ownership of the petroleum assets and the holding of the operating permits, neither the asset owner nor the permit holder have all of the rights needed to develop and operate the petroleum assets.

Offshore

The transfer of offshore interests in Nova Scotia and Newfoundland & Labrador requires a proposed transferor to first obtain an approval from either the CNSOPB or the CNLOPB (as applicable) before it transfers the interest; such consent will typically be subject to conditions.

2.10 Legal or Regulatory Restrictions on Production Rates

Canada is not a member of OPEC, but the Canadian petroleum industry has reacted quickly to changing market conditions by voluntarily slowing or shutting-in production and deferring drilling and capital projects.

Regardless of whether the ownership of petroleum vests in the federal or provincial Crown or in a freehold owner, the applicable federal or provincial authorities can regulate production rates to preserve reservoir viability, promote conservation and reduce waste.

Provinces also have broad authority to curtail petroleum production within their jurisdiction. In 2019, for example, Alberta implemented the Curtailment Rules, a temporary cap on aggregate provincial oil production to address an adverse price differential between Alberta oil and WTI. The Curtailment Rules only apply to companies that produce more than 20,000 barrels/day of oil in Alberta and are set to expire at the end of 2020.

3. Private Investment in Petroleum: Midstream/Downstream

3.1 Forms of Allowed Private Investment in Midstream/Downstream Operations

There are few limitations to participation in the midstream and downstream sectors. Subject to certain restrictions under the Competition Act regarding monopolistic behaviours, and under the Investment Canada Act to protect certain industries and asset classes from an over-concentration of foreign-ownership (see **4.1 Foreign Investment Rules Applicable to Investments in Petroleum**), investors may freely invest in midstream and downstream operations, provided that they obtain the necessary operating permits.

From an investment perspective, the regulatory requirements for refineries, petrochemical facilities and liquefied natural gas (LNG) facilities tend not to be as complex as those for large federally regulated pipelines. Provided that all required environmental approvals and operating permits have been obtained, the regulatory barriers to investment are similar to those encountered in the upstream sector.

3.2 Rights and Terms of Access to Any Downstream Operation Run by a National Monopoly

There is limited state ownership in downstream facilities, but state participation in the mid- and downstream sectors – particularly pipelines – is more common than in the upstream sector; please see **1.3 National Oil or Gas Company**.

Some downstream assets, such as major pipeline systems, can have characteristics of natural monopolies. Canadian governments have responded by creating administrative agencies to regulate these assets and their operators in an attempt to approximate market outcomes and ensure tolls and tariffs are just and reasonable. These regulators are typically responsible for assessing the need for – and the potential environmental impacts associated with – a proposed pipeline project before it can proceed. In addition, they retain ongoing operational oversight and may retain economic regulation of the pipeline.

Federal

The CER regulates interprovincial and international pipeline systems and the companies that operate them. Under its authority, all federally regulated pipelines and pipeline companies must operate according to the principle of open access. As such, all parties have broad access to transportation without discrimination if they meet the requirements of the applicable tariff.

Federally regulated oil pipelines operate as common carriers. Under common carriage, a pipeline must accept all oil offered to it for transportation, unless otherwise exempted. When transmission capacity is insufficient, available capacity must be allocated on a proportionate basis amongst all customers. Common carriage requirements can sometimes be satisfied through the operation of an appropriate open season where all shippers have the opportunity to participate. Thus, long-term contract carriage is now a feature of many federally regulated oil pipelines. To date, all major federally regulated oil pipelines that have contracted capacity also maintain some capacity available for common carriage. Of note, Canada's largest oil pipeline company, Enbridge Pipelines Inc., is currently seeking to convert its existing system from 100% common carriage to a 90% contract carriage system with the remaining 10% reserved for common carriage.

Federally regulated natural gas pipelines, on the other hand, operate as contract carriers. This means that they are not generally required to transport products from a shipper without first entering a contract.

Federal pipeline companies are classified as either Group 1 or Group 2. Group 1 pipelines tend to be larger, more complex systems with a significant number of third party shippers. They are subject to greater regulatory oversight than Group 2 companies, which are typically regulated on a complaints basis. Under a complaints-based system, pipeline companies and shippers can negotiate terms of service, subject to the shipper's ability to have the CER intervene in the event that fair and satisfactory terms of service cannot be negotiated.

Although infrequently used, the CERA contains provisions that allow shippers to apply to the CER for an order directing a pipeline operator to construct the facilities necessary to receive their petroleum, provided it is in the public interest and will not cause undue burden.

Provincial
Because there tends to be greater competition in the intra-provincial pipeline market, most provinces also use a complaints-based system to ensure fair practices, subject to a shipper's right to seek a common carrier declaration. Alberta and British Columbia have legislation that allows an oil or gas pipeline to be deemed a common carrier; Saskatchewan has legislation that allows an oil pipeline to be deemed a common carrier.

In addition to common carrier designations, the AER and the BCUC may also, by order, declare a processing facility to be a common processor.

3.3 Issuing Downstream Licences

An investor does not require any form of concession from the federal or a provincial government to develop or own a downstream project. However, extensive regulatory approvals are required before an investor can develop, own and operate a downstream project. The precise nature of these regulatory approvals depends on the nature of the project, its location, and whether it is entirely within the jurisdiction of the host province or if there is an element of federal jurisdiction.

3.4 Typical Fiscal Terms and Commercial Arrangements for Midstream/Downstream Operations

As indicated in **3.2 Rights and Terms of Access to Any Downstream Operation Run by a National Monopoly**, federally regulated pipelines are the most heavily regulated downstream operations from an economic perspective. There are three methods that regulators rely on to ensure competitive markets and just and reasonable tolls: cost of service, negotiated settlements, and open seasons.

Federal
Federally regulated pipeline operators may not charge a toll unless it is in a tariff that has been approved by regulatory order. Tariffs typically include the terms and conditions of service that govern the commercial relationship between a pipeline operator and its shippers.

Historically, larger scale federal pipelines were regulated on a cost of service basis, which requires the regulator to approve a pipeline operator's annual revenue requirements associated with the cost of providing transportation services. Under this model, a pipeline operator's tolls account for operating expenses, depreciation, return on capital, and income and other taxes, and are set to ensure that investors can recover costs and earn a reasonable return on their investment. Since the mid 1990s, the CER and its predecessor have encouraged the use of negotiated settlements as a way of achieving regulatory efficiency. Under this approach, the CER must still approve the negotiated toll to ensure that it is just and reasonable.

Open season processes are commonly used to allocate available capacity on the most significant federally regulated natural gas pipelines (and, more recently, oil pipelines to satisfy the common carrier obligations imposed on oil pipeline operators). In an open season, shippers can enter contracts for service subject to tolls that vary by duration. Thus, a longer term firm service contract will typically result in tolls that are lower than a firm contract for a shorter period.

Shippers always have recourse to the CER to make a complaint if they believe the pipeline system or operator is acting in a discriminatory and unreasonable fashion, or charging tolls that are not otherwise just and reasonable.

Provincial
Most provincially regulated pipeline systems operate on a complaints-based system. Subject to a producer's ability to request that the applicable regulator deems a processor to be a common processor, the ability of a producer to access downstream infrastructure will depend on whether it can negotiate a satisfactory agreement with the facility operator, including with respect to fees.

3.5 Income or Profits Tax Regime Applicable to Midstream/Downstream Operations

There is no separate tax regime for midstream and downstream operations.

In 2019, the British Columbia government repealed the Liquefied Natural Gas Income Tax Act, a provincial income tax regime that applied solely to the LNG industry in British Columbia, and replaced it with an income tax credit that is expected to reduce a qualifying corporation's provincial income tax by up to 3%.

3.6 Special Rights for National Oil or Gas Companies

There is no NOC in Canada; please see **1.3 National Oil or Gas Company**.

3.7 Local Content Requirements Applicable to Midstream/Downstream Operations

There are few, if any, local content requirements for midstream and downstream operations in Canada; please see **2.6 Local Content Requirements Applicable to Upstream Operations** for more information.

3.8 Other Key Terms of Each Type of Downstream Licence

Please see **3.2 Rights and Terms of Access to Any Downstream Operation Run by a National Monopoly** and **3.3 Issuing Downstream Licences**, and **1. General Structure of Petroleum Ownership and Regulation** and **5. Environmental, Health and Safety (EHS)** more generally.

3.9 Condemnation/Eminent Domain Rights

Before a downstream project can proceed, investors must obtain the right to access and occupy the surface area of the lands required for the project. Even if a project has been approved, the investor will not be able to gain access to the lands until it has negotiated for and received the consent of the landowner. If it is not possible to obtain consent through negotiation, the proponent may apply to the applicable regulatory authority for an order granting it access to the lands to carry out the project, including its construction and ongoing operation. Generally, any right of access, whether obtained through negotiation or by order, will require the investor to compensate the landowner. In addition, there are some restrictions on the foreign ownership of agricultural land in Canada.

Where the surface owner is the Crown, the investor can obtain a surface lease from the government.

3.10 Rules for Third-Party Access to Infrastructure

Please see **3.2 Rights and Terms of Access to Any Downstream Operation Run by a National Monopoly**.

3.11 Restrictions on Product Sales into the Local Market

There are no restrictions on the sale of petroleum products into local markets.

3.12 Laws and Regulations Governing Exports

The CER is responsible for issuing long-term licences and shorter term orders that permit petroleum producers to export petroleum. Most petroleum products are exported under short-term orders, which are readily obtainable from the CER. The CER may also grant long-term export licences of up to 40 years depending on the exported petroleum substance. Please see **6.2 Liquefied Natural Gas (LNG) Projects** for more information regarding LNG exports.

At the provincial level, Alberta is currently the only province that has an export permitting requirement for natural gas (the Gas Resources Preservation Act), though its historical purpose of ensuring that Alberta maintained sufficient natural gas resources is no longer pressing.

3.13 Requirements for Transfers of Interest in Downstream Licences

Generally, the process for transferring midstream and downstream assets is similar to the process for transferring upstream assets, taking into account the differences in the types of assets, types of operating permits, and regulatory oversight over such assets. Please see **2.9 Requirements for Transfers of Interest in Upstream Licences** for more information regarding this process.

Transferring a federally regulated pipeline under the CERA may require a more involved regulatory review than transferring provincially regulated midstream and downstream permits and infrastructure.

4. Foreign Investment

4.1 Foreign Investment Rules Applicable to Investments in Petroleum

Canada is a party to many bilateral and multilateral investment treaties, all of which import specific rules where foreign investment is concerned. In addition, the ICA applies when a non-Canadian establishes a new business in Canada, or proposes to acquire control of an existing Canadian business.

Under the ICA, all acquisitions of control by non-Canadians are subject to either a pre-closing "net benefit review" where certain monetary thresholds are exceeded, or a post-closing notification requirement where such thresholds have not been met. These thresholds are in Canadian dollars and increase with inflation on a yearly basis. The following thresholds are in place for 2020:

- CAD1.613 billion in enterprise value for private investors whose country of origin is party to free trade agreements with Canada (currently EU Member States, the United States, Mexico, Australia, Japan, New Zealand, Singapore, South Korea, Chile, Peru, Colombia, Panama and Honduras);

- CAD1.075 billion in enterprise value for private investors whose country of origin is a World Trade Organization (WTO) member and that are not State-Owned Enterprises (SOEs);
- CAD428 million in asset value for SOE investors, whose country of origin is a WTO member;
- CAD50 million in asset value for indirect acquisitions by non-WTO investors and indirect acquisitions of cultural businesses; and
- CAD5 million in asset value for direct acquisitions by non-WTO investors and direct acquisitions of cultural businesses.

If the investment is reviewable, the investor must demonstrate that the investment is likely to be of "net benefit" to Canada. As part of the review, the investor may be required to enter into binding undertakings with the federal government relating to the investor's conduct in Canada.

Investments by SOEs that trigger net benefit reviews are subject to additional guidelines that examine the foreign government's participation in the enterprise, and how the investment will serve the target Canadian business and the Canadian economy.

In response to the COVID-19 pandemic, the federal government recently announced enhanced scrutiny of direct investments of any value in Canadian businesses involved in the supply of critical goods and services, as well as investments by SOEs, regardless of value, or private investors that are closely tied to foreign governments.

The ICA authorises the federal government to review any investments in Canada for national security purposes. Triggers for a national security review include the transfer of "critical infrastructure", including networks, assets and services essential to the economic well-being of Canadians, as well as the impact of the investment on the supply of critical goods and services to Canadians.

5. Environmental, Health and Safety (EHS)

5.1 Principal Environmental Laws and Environmental Regulator(s)

Federal

The Impact Assessment Agency (IA Agency) is the federal agency responsible for conducting impact assessments of certain major petroleum projects that may have an impact on matters that are subject to federal jurisdiction, such as navigable waterways, fisheries or extra-jurisdictional effects. These federal impact assessments are not limited to environmental considerations. The IA Agency operates pursuant to the Impact Assessment Act (IAA). It should be noted that the Alberta government has challenged the constitutionality of the IAA. See www.canada.ca/en/impact-assessment-agency.html.

Although its regulatory mandate is broader, the CER is responsible for conducting environmental reviews of certain pipelines. Where a pipeline is a "designated project" within the meaning of the IAA, the CER will co-ordinate with the IA Agency to carry out an impact assessment. See www.cer-rec.gc.ca/index-eng.html.

In addition to these statutes, there are further federal enactments that regulate the impact of industrial activity on fisheries, navigable waterways, species at risk and migratory birds.

Provincial

In Alberta, the AER is the sole regulatory authority responsible for carrying out environmental assessments and permitting related to petroleum development, and also for the lifecycle regulation of the petroleum industry. It conducts its regulatory duties under the authority of the REDA, the Environmental Protection and Enhancement Act, the OGCA, the OSCA, the Pipeline Act and various other related statutes and regulations. See www.aer.ca.

In British Columbia, the BCOGC regulates most petroleum-related activities, including development and decommissioning. The British Columbia Environmental Assessment Office (BCEAO), on the other hand, is responsible for conducting environmental assessments of major projects. The BCOGC and the BCEAO carry out their environmental regulatory duties under the Environmental Management Act and the Environmental Assessment Act, among others. See www.bcogc.ca and www2.gov.bc.ca/gov/content/environment/natural-resource-stewardship/environmental-assessments.

In Saskatchewan, the Ministry of Environment is responsible for environmental matters related to the petroleum industry. The principal environmental statute is The Environmental Management and Protection Act. See www.environment.gov.sk.ca.

5.2 Environmental Obligations for a Major Petroleum Project

Whether a petroleum project requires an environmental assessment depends on the nature of the proposed project. Larger, more complex projects with greater impacts are likely to require tailored environmental and/or impact assessments. If a formal assessment is required, a party cannot begin constructing or operating the project until the assessment is completed. The complexity of the project, the risk it poses to the environment, and the degree of public participation will affect the length of the assessment process.

Please see **6.3 Unique or Interesting Aspects of the Petroleum Industry** for more information regarding consultation with First Nations and Indigenous groups.

5.3 EHS Requirements Applicable to Offshore Development

Consistent with onshore petroleum regulators in Canada, the various regulatory bodies tasked with overseeing the development of offshore petroleum utilise a cradle-to-grave regulatory approach. Throughout a project's lifecycle, operators must submit a variety of plans intended to ensure the safe and orderly development of offshore petroleum, including environmental protection plans, development plans, occupational health and safety plans, and local benefits plans.

Finally, and in addition to other financial resources requirements, operators in Canada's offshore are liable for loss or damage that they cause, regardless of negligence or fault. This is known as absolute liability. Subject to the discretion of the applicable regulator, operators must demonstrate that they have readily accessible financial resources equivalent to their absolute liability.

5.4 Requirements for Decommissioning

Regardless of jurisdiction, the polluter pays principle underlies the regulation of petroleum development in Canada, including the decommissioning of petroleum infrastructure.

Onshore

Decommissioning is an exercise in risk mitigation. Before decommissioning a well, for example, an operator must first assess the risk that the well poses to environmental and public health, as this will determine how it will be decommissioned. Once an operator decides to decommission a well, it must generally provide notice to the regulator and, for non-routine abandonments, obtain authorisation. Facilities are subject to similar requirements.

Regarding pipelines, there are uniform technical standards that apply to the decommissioning of federally and provincially regulated pipelines in Canada.

In addition to decommissioning the infrastructure associated with a well, facility or pipeline, the operator must also reclaim the surrounding surface lands, and investors may remain liable for the costs associated with any consequential harm that arises from decommissioning. In certain circumstances, this liability persists even if the person no longer has an interest in the site. The July Statement also indicates that changes will be made to provide for mandatory annual spending targets for the abandonment of inactive wells and a new framework to ensure that previously abandoned assets meet current standards.

To minimise the risk of insolvency and unfunded decommissioning obligations, the federal and provincial regulators each administer programmes to manage liability and ensure that operators have the financial resources necessary to meet their decommissioning obligations. These programmes include liability management programmes, industry-supported funds to defray the cost of decommissioning orphaned infrastructure, and financial resources requirements and security deposits. Please see **2.9 Requirements for Transfers of Interest in Upstream Licences** and **6.4 Material Changes in Oil and Gas Law or Regulation** for more information.

Offshore

Canada's offshore has been the site of petroleum exploration since 1959, but commercial production did not begin until 1992. While there are regulatory frameworks in place to govern offshore abandonment, offshore operators are only just starting to decommission major offshore infrastructure. As such, few major decommissioning applications have undergone detailed regulatory reviews, although it is likely that the regulatory processes legislators have implemented to organise the decommissioning of onshore petroleum infrastructure will guide some of the practices utilised in offshore regulation. Canada is also a signatory to a number of international treaties concerning the ocean. While these treaties do not necessarily limit the discretion of offshore regulators, they will likely inform the approach that they take to ensuring safe and environmentally sound practices.

Depending on the unique features of an offshore project, the regulated decommissioning of offshore petroleum infrastructure will require applications to both the federal and provincial regulators, a decommissioning plan, and a consideration of potential economic, commercial and socioeconomic impacts arising from decommissioning operations and the associated physical activities.

5.5 Climate Change Laws

Federal

Canada is a signatory to the United Nations Framework Convention on Climate Change and the Paris Agreement. In connection with these international commitments, the federal government has pledged to reduce its domestic emissions by 30% from 2005 levels by 2030 as part of a larger international effort to limit the rise of global temperatures. To help achieve this goal, the federal government has implemented a price on certain types of emissions.

The Greenhouse Gas Pollution Pricing Act (GGPPA) is an emissions pricing regime that became effective on 1 January 2019. It consists of two parts:

- a regulatory fuel charge for fuel consumption; and
- an output-based emissions pricing programme for large emitters.

The current price is CAD30 per tonne of carbon dioxide equivalent (CO_2e), increasing by CAD10 per year until it reaches CAD50/tonne in 2022.

The GGPPA only applies in provinces and territories that the federal government has not recognised as having implemented their own equivalent programmes. For example, British Columbia, Nova Scotia and Newfoundland & Labrador have enacted fuel charge legislation that meets the federal equivalency requirements, and the federal fuel charge regime does not apply in those provinces. Alberta and Saskatchewan, on the other hand, have not enacted provincial fuel charge legislation that meets federal equivalency requirements, so the federal programme applies.

At the time of writing, a constitutional challenge concerning the validity of the GGPPA is pending before the Supreme Court of Canada.

The federal government has also implemented the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector), which aim to reduce methane emissions and ensure that petroleum operations use low-emission equipment and processes.

Provincial

Alberta

While Alberta is subject to the federal fuel charge, it has implemented an output-based emissions pricing programme for large emitters, called the Technology Innovation and Emissions Reduction (TIER) regulation. Under TIER, large industrial emitters must reduce their annual emissions by 10% in 2020 and 1% per year thereafter, as measured against a facility-specific emissions benchmark. The Alberta government has also implemented the Methane Emission Reduction Regulation, which aims to reduce methane emissions in the province by 45% by 2025. Finally, and specific to oil sands development, the Oil Sands Emissions Limit Act implements a 100 million tonne cap on annual CO_2e emissions, but this cap is not yet effective.

British Columbia

The British Columbia Climate Leadership Plan aims to reduce British Columbia's net annual emissions by up to 25 million tonnes below current forecasts by 2050, and recommits the province to achieving a target of reducing emissions by 80% below 2007 levels by 2050.

The Greenhouse Gas Industrial Reporting and Control Act sets out various performance standards for different industrial sectors and provides for emissions offsets through the purchase of credits or through emission offsetting projects.

British Columbia has also committed to a number of other initiatives to reduce emissions, such as:

- increasing electricity generation from clean sources;
- imposing a 15% renewable content requirement in natural gas by 2030;
- requiring fuel suppliers to reduce the carbon intensity of diesel and gasoline by 20% by 2030;
- investing in the electrification of petroleum production; and
- reducing 45% of methane emissions associated with natural gas production.

The British Columbia Drilling and Production Regulation was recently amended to require permit-holders to reduce natural gas leaks and curb monthly natural gas emissions from their equipment and operations.

Saskatchewan

The Management and Reduction of Greenhouse Gases Act (the MRGGA) regulates GHG emissions in the province. The MRGGA is partially compliant with the federal large emitters programme, and establishes a framework to reduce GHG emissions by 20% of 2006 levels by 2020. The MRGGA also establishes the framework of an output-based emissions management framework.

The Oil and Gas Emissions Management Regulations regulate flared and vented methane emissions in the upstream petroleum sector, with the goal of achieving annual emissions reductions of 40% to 45% by 2025.

5.6 Local Government Limits on Oil and Gas Development

While local municipal governments may be required to issue certain permits to petroleum projects, they lack the authority and jurisdiction to limit petroleum development where a provincial or federal regulatory authority has approved the relevant project. However, municipal permits may be subject to conditions, as long as such conditions are not incompatible with and do not frustrate the underlying federal or provincial approval.

6. Miscellaneous

6.1 Unconventional Upstream Interests

Heavy Oil

The requirements related to the development of oil sands resources are similar to conventional resources, with additional requirements that may apply, depending on the proposed development strategy. For example, a "project scheme" may be required to allow for larger-scale oil sands production on smaller parcels of leased land rights. Project schemes are obtained through application to the AER.

Shale Gas

Shale gas is regulated under the same legislation as conventional natural gas in Alberta. Due to perceived risks associated with ground water contamination and increased seismic activity, investors must submit an application to the AER, and receive approval on the project prior to completing any hydraulic fracturing activities, and must adhere to additional monitoring and reporting during drilling and production.

Alberta and British Columbia have developed a public reporting tool for the amount and sources of water used and the chemicals used in hydraulic fracturing (www.fracfocus.ca). The CER requires similar public reporting for activities under its jurisdiction.

The Alberta Geological Survey is a division of the AER that monitors the risk of seismic activity across the province. The AER has developed specific seismic protocols for high-risk areas in the province. Each area has a threshold for seismic activity, which triggers increasing obligations on the investor as seismic activity increases, which may include ceasing operations until the AER can establish it is safe to do so.

In 2018, the BCOGC designated the Kiskatinaw Seismic Monitoring and Mitigation Area in northeastern British Columbia (the Kiskatinaw Area) to investigate a number of seismic events and determine their connection to natural gas development in the area. Permit holders in the Kiskatinaw Area are subject to additional requirements before they can conduct hydraulic fracturing operations, including developing a seismic monitoring and mitigation plan that is approved by the BCOGC, and notifying the BCOGC and local residents about planned hydraulic fracturing requirements. During active hydraulic fracturing operations, permit-holders are required to deploy an accelerometer, to have access to real-time seismicity readings and to report such readings to the BCOGC on demand.

The Government of Saskatchewan requires a frac report to be submitted within 30 days of a well completion being fractured. The frac report must include information on chemicals and fluids used and the disposal methods for fluids and sand.

6.2 Liquefied Natural Gas (LNG) Projects

LNG export requires approval from the CER. The maximum length of an LNG export licence is 40 years. In reviewing applications for export licences, the CER considers whether the amount of natural gas proposed to be exported is surplus to Canadian demand. Permits for LNG facilities will need to be obtained from the applicable federal or provincial regulatory bodies.

There are tax incentives in place for LNG facilities in Canada; please see **3.5 Income or Profits Tax Regime Applicable to Midstream/Downstream Operations** for more information.

6.3 Unique or Interesting Aspects of the Petroleum Industry

Canada is a signatory to the United Nations Declaration of the Rights of Indigenous Peoples (UNDRIP). While UNDRIP does not have the force of law in most of the country, British Columbia recently took legislative steps to align its provincial laws with UNDRIP, and the federal government has announced its intention to enact similar legislation.

Government Consultation

In Canada, First Nations and other Indigenous groups possess constitutionally protected rights ("Aboriginal Rights"). Depending on the nature of a project, Canadian law requires the federal or provincial government to consult with potentially affected Indigenous groups and, where appropriate, accommodate their interests (the "Duty to Consult"). The scope of the Duty to Consult is determined with reference to the potential impact of government action on asserted or established Aboriginal Rights. In this context, government action can include approving a petroleum project. In cases where the degree of potential impact on Aboriginal Rights is low, the required depth of consultation will be on the lower end of the spectrum. Conversely, where the potential impact on Aboriginal Rights is significant, the Duty to Consult may require deep interaction, including one-on-one meetings between the potentially affected group and government officials. In these circumstances, there will likely be additional requirements to accommodate the concerns of the First Nation or Indigenous group whose Aboriginal Rights may be adversely impacted.

Consultation by Investors

Typically, investors will consult with potentially impacted First Nations and Indigenous groups during the regulatory approval process to help fulfil the government's Duty to Consult. As part of this process, it is not uncommon for investors and potentially impacted First Nations and Indigenous groups to enter benefit sharing agreements that provide for funding or infrastructure development initiatives, as well as preferential training and hiring programmes.

At both the federal and provincial level, the consideration of potential impacts on First Nations and other Indigenous groups and the adequacy with which the government consulted with and, if necessary, accommodated the potentially impacted groups often forms a significant part of any regulatory proceeding concerning the approval of a petroleum project. Allegations of insufficient consultation by government and, in some cases, investors can lead to litigation that can seriously delay or derail a petroleum project. Investors seeking to invest in Canadian petroleum projects should familiarise themselves with these potential issues as part of their due diligence.

6.4 Material Changes in Oil and Gas Law or Regulation

The combined effects of the decreased demand for petroleum due to the COVID-19 pandemic and the increased supply of petroleum during the OPEC+ battle for market share during the first half of 2020 have led to a number of material changes in the laws and policies that affect Canada's petroleum industry.

One set of changes can be grouped together as a stimulus package. Canadian governments have developed a number of programmes that have the potential to have a positive impact on the petroleum industry. These programmes signal that the governments' priority is to keep businesses open, protect jobs and workers, and safeguard the environment. To that end, the federal government has:

- pledged to invest up to CAD1.72 billion to assist in the decommissioning of orphan and inactive wells in western Canada;
- announced that the Business Development Bank of Canada and Export Development Canada will be providing liquidity and credit support to the petroleum industry; and
- initiated the Large Employer Emergency Financing Facility, which will permit qualified applicants to obtain significant bridge financing for operating expenses.

In addition, the Alberta government has provided a loan to its OWA to assist with decommissioning efforts; reduced provincial corporate income tax rates; and announced the Alberta Petrochemicals Incentive Program, which will make grants available to companies for new or expanded petrochemical facilities. Saskatchewan has reduced the industry's share of its orphan well levy for 2020.

A second set of changes is operational in nature:

- the federal government has created a CAD750 million Emissions Reduction Fund, one focus of which is to reduce methane emissions. Some of this fund is earmarked for the offshore petroleum industry;
- both Alberta and Saskatchewan have extended the termination dates in some of their Crown leases;
- land sales for Alberta and British Columbia Crown petroleum rights have been cancelled or deferred; and
- in Alberta, the July Statement foreshadows a number of changes intended to reduce the current inventory of orphan facilities and to reduce the risk of additional facilities becoming orphans.

As Canadian governments continue to manage the impacts of COVID-19, it is expected that they will continue to announce legislative and policy changes and initiatives intended to help industry navigate the challenges brought about by the pandemic and improve regulatory efficiency.

Other non-COVID legal developments of note include the following:

- despite legal challenges and illegal protests and blockades related to the construction of the Trans Mountain Pipeline expansion, construction of the expansion is underway on a number of legs. Courts of all levels, including the Supreme Court of Canada, have repeatedly confirmed the validity of the approvals for and processes undertaken in respect of the pipeline. In March 2020, the Supreme Court of Canada declined to hear five additional challenges to the federal government's decision to approve the expansion and, in June 2020, declined to hear additional challenges to the adequacy of the government's consultation efforts; and
- in 2019, the Supreme Court of Canada released its decision in Orphan Well Association, et al. v. Grant Thornton Limited, (the "Redwater" case). Redwater is an important bankruptcy case with direct implications for the petroleum industry. It stands for the proposition that a representative of a bankrupt company cannot "disclaim" uneconomic wells and sell the economic wells for the benefit of the bankrupt company's creditors (eg, its bank), leaving the disclaimed wells as "orphans" to be dealt with by the government. In effect, the bankrupt company's creditors do not have priority over the decommissioning obligations the bankrupt company owes to the regulator and the public. This case has already had a profound impact on the petroleum industry, and such impact will certainly evolve through the stress that the COVID-19 pandemic has put on the petroleum industry and the layers of new laws and policies related to stimulus and the environment.

Burnet, Duckworth & Palmer LLP is a leading Calgary-based, independent Canadian law firm with more than 115 lawyers, servicing all areas of business law. The energy group of 15 lawyers advises on all aspects of domestic and international oil and gas infrastructure projects, joint ventures, alliances and M&A. It represents a diverse range of clients, including multinational corporations, private corporations, private equity investors, governments, and state-owned-entities. Key transactions include advising USD Group LLC on the joint venture with Gibson Energy and the project development of a Diluent Recovery Unit in Hardisty, Alberta, and acting for the Alberta Petroleum Marketing Commission in respect of a CAD1.5 billion equity investment and a CAD6 billion loan guarantee in connection with the construction of the Keystone (KXL) Expansion.

Authors

Sean Korney is a partner with more than 25 years' experience in the energy industry, including 13 years based in Dubai and Singapore with leading US and UK law firms. His international experience includes handling matters in the Americas, the Middle East, Africa, Asia and Australia. Sean's expertise covers M&A, project development, commercial transactions, dispute resolution and strategic advice. He is a member of the Law Society of Alberta, the Law Society (England and Wales), the Association of International Petroleum Negotiators and the Canadian Global Exploration Forum.

Carolyn Wright is a partner with more than 17 years' experience, focusing on energy and commercial transactions, project development and aboriginal law. She is the co-leader of BD&P's Energy group and a member of the firm's Executive Committee. Carolyn is experienced in energy M&A and project development relating to upstream, midstream and downstream activities, including pipelines and rail, as well as related energy regulatory matters. She is a past Director and President of the Canadian Energy Law Foundation and past-president of the Canadian Bar Association – Natural Resources Section. She is a member of the Law Society of Alberta and the Calgary Bar Association.

Evan Dixon is a partner with more than 15 years' experience. His practice focuses on administrative, regulatory, environmental and Aboriginal law matters related to the energy industry. Evan has appeared before the Alberta Energy Regulator, the Alberta Utilities Commission, the Canada Energy Regulator (and its predecessor the National Energy Board) and other administrative tribunals, as well as at all levels of Court in Alberta and the Federal Courts. His recent notable experience includes acting as counsel to the Government of Alberta regarding the Trans Mountain Pipeline Reconsideration proceeding before the NEB, and defending the constitutionality of Alberta's Bill 12 before the Alberta and Federal Courts. Evan is a member of the Law Societies of Alberta and the Northwest Territories.

Brendan Downey is an associate and has three years' experience in advising on domestic and international oil and gas transactions and various regulatory matters. He has acted as junior counsel for the Government of Alberta in the National Energy Board's reconsideration of the Trans Mountain Pipeline Expansion, appeared before the Supreme Court of Canada in BC's "Pipeline Reference", and acted as counsel to the Government of Alberta regarding its investment in the Keystone XL Pipeline. He has published articles in the Alberta Law Review, Energy Regulation Quarterly and the Annual Review of Insolvency Law. Brendan is a member of the Law Society of Alberta.

Burnet, Duckworth & Palmer LLP

#2400 525 8 AVE SW
Calgary, AB T2P 1G1

Tel: 403-260-0206
Fax: 403-260-0332
Email: skorney@bdplaw.com
Web: www.bdplaw.com