



Guide to oil and gas taxation in Canada

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Preface

On May 14, 1914 in Turner Valley, Alberta, the famous Dingman Discovery Well spewed natural gas. This signified an important day for the Canadian oil and gas industry. Over the 100 years since this foundational event, the industry has seen considerable change. Commodity prices have been significantly volatile, energy markets have expanded, technology has improved, and oil sands have become commercially viable. In the process, the Canadian oil and gas industry has shifted from a domestic industry to an international energy supplier.

One consequence of this growth is that governments within Canada have increased the taxes levied on the industry. At the same time, they have taken measures to enforce environmentally and socially responsible development. Faced with these challenges, oil and gas companies have remained committed to sustainable, economical, and responsible development of the industry.

This book is intended for business professionals and for others with an interest in the oil and gas industry. It outlines the provisions of Canada's federal and provincial income tax legislation that are applicable to this industry, and it summarizes the provincial statutes that impose taxes and royalties on those engaged in the industry. It also describes other legislation that is relevant to oil and gas activities in Canada.

We trust that this book will be a helpful summary of the main features of Canada's current oil and gas tax regime. It should prove useful both to readers planning to undertake oil and gas exploration and development activities in Canada and to readers who wish to invest in Canadian energy entities. We hope, too, that it will be a useful guide to basic taxation matters affecting the oil and gas industry.

Readers who require further information or assistance are invited to contact any of KPMG's oil and gas professionals listed on page 85.



Torran Jolly, CPA, CA
Partner & General Editor



Introduction

CANADA'S OIL AND GAS INDUSTRY

Canada's oil and gas industry is important to the nation's economic well-being. In 2016, exploration and production in this industry were ongoing in 12 of Canada's 13 provinces and territories.¹ In 2014, the industry contributed approximately \$17 billion in taxes and royalties to governments, and it employed, directly and indirectly, 440,000 persons across Canada.²

Canada is a leading producer of oil and gas worldwide. In 2014, it was the fourth-largest producer of natural gas in the world and the fifth-largest producer of crude oil. The demand for Canada's petroleum resources is expected to increase as existing reserves elsewhere in the world decline.

Emerging economies, such as those of China and India, are driving energy demands upwards, and economists believe this trend will continue, with a steady increase in oil consumption, until 2035. Despite increasing demand, the prices for petroleum products continue to fluctuate.

Many factors contribute to fluctuations in oil and gas prices. These factors include the following:

- *Variations in demand owing to seasonal weather changes.* Demand is lower in the spring and fall. Additional travel in summer and cold weather in winter increase demand; in contrast, less travel and moderate temperatures reduce demand in spring and fall.
- *Weather conditions.* Severe weather events, such as hurricanes, may damage oil and gas infrastructure. This limits supply and leads to higher prices.
- *Production and capacity levels.* Higher inventory and production levels mean a greater supply and a reduction in prices. By the same token, lower inventory and production levels mean a reduced supply and increased prices.
- *Technological improvements.* Technological advancements in the industry lead to greater recoveries in areas of existing production, to discoveries in entirely new areas, and to extraction in areas where it was previously not viable.

The general effect is increased production, which increases supply and reduces prices.

- *Depletion of conventional sources.* Global energy demands have depleted conventional oil and gas deposits, and this process is ongoing. As conventional oil and gas have become harder to find, unconventional methods of production, such as those from shale formations, have become more necessary. Such methods are more expensive and lead to higher production costs.
- *Political instability and conflict in various regions around the world.* Energy demands and needs have historically contributed to various political issues. Some of these issues have resulted in political unrest and conflict. These factors normally result in an increase in commodity prices.

The instability in petroleum commodity prices has contributed to volatility in the stock prices of Canadian petroleum producers. Despite this volatility, Canada's stable political climate, abundance of natural resources, and fluctuating petroleum commodity prices have resulted in an attractive environment for mergers and acquisitions in the oil and gas industry.

¹ <http://www.capp.ca/canadaIndustry/industryAcrossCanada/Pages/default.aspx>

² <http://www.capp.ca/library/statistics/basic/Pages/default.aspx>

THE TAX ENVIRONMENT

The taxes imposed by any particular government are crucial to the viability of an oil and gas project. Too high a tax burden can make a project uneconomic, even though the project has excellent oil and gas prospects otherwise.

Canada's system of government consists of a federal government and 10 provincial governments, as well as three territories under the federal government's jurisdiction. The federal government, the provinces, and the territories each levy income taxes on corporations and individuals. Each of the provinces and the territories also levies separate royalties on oil and gas activity (for tax purposes, there is little distinction between a province and territory; consequently, any subsequent reference in this book to provinces includes the territories).

In many respects, Canada's tax environment is favourable to business, and especially to oil and gas activities. Where this industry is concerned, the following are some of the favourable features of the current tax system in Canada:

- The rates of income tax are low relative to most other jurisdictions in which oil and gas activities take place.
- The rapid write-off of intangible expenses and of the cost of tangible assets permits taxpayers to recover the costs of bringing a well into production before they must pay any tax.
- Tax deductions for intangible expenses reduce the tax liability of corporations. Such deductions can be carried forward indefinitely.
- Operating losses can be carried forward for as long as 20 years. This makes it almost certain that a taxpayer that does develop viable oil and gas operations will be able to use start-up losses.
- Only one-half of a capital gain is included in income.
- Most capital taxes have either been eliminated or are being phased out in most jurisdictions in Canada.
- Most provinces have sales and use taxes that allow businesses to pass along the tax to the ultimate consumer. This means that, in the end, businesses do not bear the cost of these taxes.
- A flow-through share mechanism allows corporations to renounce intangible expenses to investors. This allows corporations to monetize expenses that they are unable to utilize in the foreseeable future.
- There is no withholding tax on interest paid by a corporation to an **arm's length** non-resident lender.
- Most of Canada's tax treaties provide that the rate of withholding tax on dividends paid to a non-resident parent company is limited to 5 percent.

The following features of the Canadian tax system are not so favourable to the oil and gas industry:

- Some provinces (e.g., Manitoba, Saskatchewan, and British Columbia) impose sales and use taxes that are borne by businesses, rather than by the ultimate consumer.
- Some provinces require oil and gas operators to pay royalties rather than profit-based taxes.
- There are other taxes and charges for which a business is liable, whether or not it is profitable. These include Canada Pension Plan and Employment Insurance payments at the federal level, carbon taxes or levies, and health taxes and payroll taxes at the provincial level.

ABOUT THIS BOOK

We anticipate that the demand for petroleum and petroleum-related products will continue to grow and that future activity worldwide in the oil and gas industry will remain robust. We have written this book for business entities that invest in oil and gas activities to help them understand the Canadian tax regime and how it applies to such activities in Canada and abroad.

This book summarizes the Canadian legislation relevant to the oil and gas industry and provides an overview of the broad legislative principles applicable to any particular activity in this industry. The statements of the law are current to September 30, 2017, but updated to January 1, 2018 in some circumstances. At that time, there was some legislation in draft form, not yet finalized. For ease of discussion, we have assumed that all such proposed legislation will become law. Where the proposed legislation has not been enacted, the government responsible for it usually provides transitional legislation for the benefit of those taxpayers reliant on the proposed legislation.

This book concentrates on the federal, provincial, and territorial taxes applicable to oil and gas activities and does not consider other taxes and charges, such as payroll taxes, or taxes in provinces that have limited oil and gas activity. A person contemplating carrying on business in Canada should consult a tax adviser about these other taxes.

The relevant tax rules are detailed and complex, and we have not endeavoured to discuss the many nuances of such legislation. We have eschewed the word “generally” and the phrase “in general” in order to make the text simpler and more readable. We accept that there may be esoteric exceptions to many of our statements. However, we consider it important to give readers straightforward statements that may not be true in every factual circumstance, rather than to bog them down in unending caveats. Given our policy in this regard, this book should not be seen as a substitute for consultation with a knowledgeable tax adviser. For a more detailed and technical review of the federal legislation, see *Canadian Resource Taxation*, General Editors, Brian R. Carr and and Torran Jolly, CPA, CA (Toronto: Carswell, loose leaf).



User key

We have attempted to make the content of the book user-friendly by keeping to a bare minimum specific references to legislative provisions. In addition, we have provided:

Glossary

Roll over the bolded words to view tax terms, oil and gas terms and abbreviations.

Cross-references

Cross-references where a particular concept is more fully discussed in another section of the book; these cross-references are colour-coded blue and italicized for easy identification.

Index

An index is included to guide the reader to the pages where specific topics are discussed.

Overview of the Canadian tax regime

OIL AND GAS ACTIVITIES

Canada's tax regime for oil and gas activities applies to four principal stages of operations:

- exploration and development;
- production;
- processing (including separating and refining); and
- decommissioning.

The tax regime provides for special treatment of these activities, to create and maintain a favourable environment for investment in the oil and gas sector. This special treatment includes deductions, allowances, and credits that may be claimed against the income from the petroleum operation, either in the year of expenditure or, sometimes, in a prior or subsequent year.

Different rules may apply to different forms of organizations. It is therefore important to consider the applicable tax treatment before deciding what type of structure will be used for investment in an oil and gas project.

FORMS OF ORGANIZATION

Canadian tax law contemplates that oil and gas activities may be carried on by an individual, a corporation, a trust, or a partnership. Such legislation also provides for the issuance of **flow-through shares** by a corporation, which permit the corporation to renounce its deductible resource expenses to the purchasers of the shares.

A non-resident individual or corporation may carry on business directly in Canada or indirectly through a Canadian corporation.

The use of **partnerships** and **joint ventures** has always been common in structuring investments in the oil and gas industry. These forms of organizations allow various projects to be “ring-fenced”. This reduces administration and management. In addition, oil and gas projects have become more international in scope as other countries (such as China, Korea, Malaysia, Japan, and India) look to external sources for supplies. As a result, partnerships and joint ventures increasingly include foreign entities that contribute funding to the Canadian corporations that

own the resources and have the operating expertise. These non-resident investors may participate directly in the projects. More typically, however, they will participate through Canadian subsidiaries, so that all the members of the joint venture or partnership will be Canadian corporations.

Trusts are excellent vehicles for flowing income through to their beneficiaries; however, trusts cannot flow losses through to their beneficiaries. As a result, trusts are not used frequently in active oil and gas operations, although they may be used as investment vehicles to purchase royalties and other oil and gas working interests. Trusts are taxed as individuals on their income except in respect of income that is subject to the **SIFT legislation** (discussed in [Structuring Oil and Gas Investments – Partnerships and Joint Ventures – Income Tax Consequences – SIFT Legislation](#)).



INCOME TAXATION

Both the federal and provincial governments levy income taxes on corporations and individuals. In all provinces except Québec and Alberta, a single corporate tax return is filed. In all provinces except Québec, a single personal income tax return is filed, with the federal government collecting both taxes. In Québec and Alberta, the basis for taxation is similar to the basis for federal taxation.

Individuals, corporations, and trusts are all subject to federal income tax under Canada's **Income Tax Act (ITA)**. Most **partnerships** are not themselves liable to tax; instead, the individual partners are taxed on the share of partnership income allocated to them.

The basis for federal taxation in Canada is residency. Residents of Canada are taxed on their worldwide income, whether from sources inside or outside Canada. Non-residents are taxed only on their Canadian-source income (subject to any available treaty exemption). Corporations incorporated in Canada are resident in Canada regardless of the residency or nationality of their shareholders.

Individuals are subject to federal tax and provincial tax in the province in which they are resident on the last day of the calendar year (December 31). However, business income earned through a permanent

establishment is subject to tax in the province or territory of the permanent establishment.

The ITA provides for abatement for income earned by a corporation through a permanent establishment in a province or territory. Where a corporation carries on business in two or more provinces, there is an allocation formula that allocates the income between those provinces.

The ITA also allows a 100 percent deduction for provincial **royalties** and production taxes payable.

The calculation of tax follows the following four steps:

- 1 Income (also called net income) is calculated.
- 2 Certain deductions are claimed to reach taxable income.
- 3 Federal tax and provincial tax are calculated on taxable income.
- 4 Applicable tax credits are applied to reduce taxes payable.

Resident corporations are taxed at flat corporate rates. The combined federal and provincial rates range from 26 percent to 31 percent for the 2018 calendar year, depending on the province or territory. Table 1 shows the federal and provincial income tax rates for each province and territory for 2018.

Table 1: Federal and provincial corporate income tax rates applicable 2018

	Rates as at January 1, 2018 (percent)		
	Federal	Provincial	Combined
British Columbia	15.0	12.0	27.0
Alberta	15.0	12.0	27.0
Saskatchewan	15.0	12.0	27.0
Manitoba	15.0	12.0	27.0
Ontario	15.0	11.5	26.5
Québec	15.0	11.7	26.7
New Brunswick	15.0	14.0	29.0
Nova Scotia	15.0	16.0	31.0
Prince Edward Island	15.0	16.0	31.0
Newfoundland and Labrador	15.0	15.0	30.0
Yukon	15.0	12.0	27.0
Northwest Territories	15.0	11.5	26.5
Nunavut	15.0	12.0	27.0

British Columbia increased its general corporate income tax rate from 11.0% to 12.0%, effective 1 January 2018.

Saskatchewan increased the general corporate income tax rate from 11.5% to 12.0%, effective 1 January 2018.

Québec's 2015 budget proposed to gradually reduce the general corporate income tax rate for active business, investment, and M&P income from 11.9 percent to 11.5 percent beginning in 2017. The rate decreased to 11.8 percent in 2017 and will decrease to 11.7% in 2018, 11.6 percent in 2019 and 11.5 percent in 2020. The rate reductions will be effective January 1 of each year from 2017 to 2020.

Canadian-resident individuals are taxed at graduated rates based on federal and provincial tax brackets. Table 2 shows the maximum federal and provincial

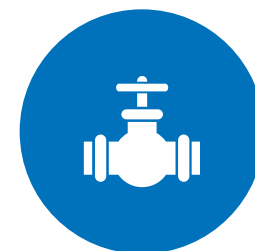
income tax rates and the highest tax brackets for each province and territory for the 2018 calendar year.

Non-residents are subject to federal withholding tax on payments received from Canadian residents. The payer withholds tax on the payment at a rate specified under the ITA or at a reduced rate as provided by an applicable tax treaty.

Table 2: Maximum federal and provincial personal income tax rates for 2018

	Federal rate (percent)	High federal tax bracket (\$)	Provincial rate (percent)	High provincial tax bracket (\$)
British Columbia	33.00	205,843	16.80	150,001
Alberta	33.00	205,843	15.00	307,548
Saskatchewan	33.00	205,843	14.50	129,215
Manitoba	33.00	205,843	17.40	68,822
Ontario	33.00	205,843	13.16	220,001
Québec	33.00	205,843	25.75	104,766
New Brunswick	33.00	205,843	20.30	154,383
Nova Scotia	33.00	205,843	21.00	150,001
Prince Edward Island	33.00	205,843	16.70	63,970
Newfoundland and Labrador	33.00	205,843	18.30	184,591
Yukon	33.00	205,843	15.00	500,001
Northwest Territories	33.00	205,843	14.05	137,248
Nunavut	33.00	205,843	11.50	144,489

Ontario, Prince Edward Island, and Yukon also impose surtaxes. The maximum surtax rate is 36 percent in Ontario and 10 percent in Prince Edward Island. Accounting for the surtaxes, the highest marginal rate is 20.53 percent in Ontario and 18.37 percent in Prince Edward Island. Québec taxpayers receive an abatement that reduces the highest-bracket combined rate to 53.31 percent.



Capital gains

A disposition of **capital property** may give rise to a capital gain, 50 percent of which is included in income as a **taxable capital gain**.

Utilization of losses

There are two types of losses for Canadian tax purposes, **non-capital losses** and **net capital losses**. Non-capital losses are business or property losses that may be carried back for 3 taxation years or carried forward for 20 taxation years, to be applied against income from any source.

Capital losses are losses incurred on a disposition of capital property. One-half of such losses (**allowable capital losses**) may be deducted against the taxable portion of capital gains realized in the year, with any excess being carried back or forward as a net capital loss. Net capital losses may be carried back for three years or carried forward indefinitely, but may be deducted only against capital gains.

There is currently no tax consolidation or group relief in Canada; the losses of one corporation in a corporate group cannot be deducted against the income of another corporation in the group in the tax returns of the corporations. Various reorganization techniques allow corporations to utilize losses within a corporate group.

The Canadian tax system provides corporations in the oil and gas sector with flexibility in managing their non-capital losses and discretionary deductions before they expire.

Where there is an amalgamation of two or more corporations and there is no acquisition of **control** of a predecessor corporation by virtue of the amalgamation, the amalgamated corporation can utilize the losses of the predecessor corporations as if those losses were its own.

Where there is an amalgamation of a parent and a wholly owned subsidiary, the amalgamated corporation can carry back any losses it realizes against income of the parent subject to the restrictions described below.

Where a parent corporation winds up a subsidiary corporation in accordance with the tax-deferral rules, the losses of the subsidiary can be applied against income of its parent in the taxation year beginning after commencement of the wind-up.

Restrictions apply to the utilization of losses of a corporation on an acquisition of control of the corporation, whether by way of amalgamation or otherwise.

The rules applying to corporate reorganizations, amalgamations, and wind-ups are discussed in [Structuring Oil and Gas Investments – Corporate Reorganizations](#).

TAX ADMINISTRATION

The ITA is administered by the Canada Revenue Agency (CRA). The CRA has powers to conduct audits, require the production of tax-related information, collect taxes owing, and impose interest and penalties on unpaid amounts.

To assist taxpayers in the application of the federal income tax rules and regulations, the CRA publishes guidance in the form of information circulars, income tax folios, technical interpretations and bulletins, and periodic releases as required. It also provides advance tax rulings in response to taxpayer requests for clarification of the tax treatment that may apply in particular situations.

Provincial tax legislation is administered by the appropriate government department or ministry (usually Finance). These provincial tax authorities also publish guidance on the application of the legislation, in various forms.

The websites of the federal and provincial tax authorities are listed in the Appendix.

FILING REQUIREMENTS AND TAX PAYMENTS

Corporations

Corporate income tax returns are due six months following the end of the corporation's fiscal year. With the exception of Alberta and Québec, the federal government collects taxes on behalf of the provinces, so an additional provincial corporate income tax return is not required.

Corporations are required to pay monthly federal and provincial tax instalments during the year.

The balance of federal and provincial taxes owing (after instalments) is due three months after the end of the taxation year for a Canadian-controlled private corporation and two months after the end of the taxation year for all other corporations. Alberta and Québec have legislation similar to that of the federal government, as described above.

Individuals

Individuals must use a calendar year for tax purposes. Federal and Québec personal income tax returns for individuals other than self-employed individuals must be filed by April 30 of the following year. Self-employed individuals with professional income or income from an unincorporated business have until June 15 of the following year to file their federal and Québec personal income tax returns.

Employed individuals are subject to source withholdings by the employer (payroll tax). Individuals who are not employed but have income from a business or property above a specified threshold are required to pay quarterly federal and provincial income tax instalments.

The balance of federal and provincial tax owing for a taxation year is due by April 30 of the following year.

Trusts

There are two categories of trusts, **inter-vivos trusts** and **testamentary trusts**. Inter-vivos trusts are established by a living person; a testamentary trust is established on the death of an individual. Inter-vivos trusts, which include virtually all commercial trusts, must have calendar fiscal years. They must file federal and, if applicable, Québec returns, and pay the balance of tax owing (after instalments) within 90 days of the end of each taxation year. Testamentary trusts can, for a limited period, establish a year-end that is different than a calendar year. Special rules apply to the filing requirements of testamentary trusts. Testamentary trusts are very rarely used in commercial arrangements.

Partnerships

A **partnership** is not a taxpayer in its own right. The tax liability in respect of the business of the partnership is imposed on its partners except in the case of

specified investment flow-through entities (SIFTs), which are taxed on their earnings from **non-portfolio property**, (the **SIFT legislation** is discussed in [Structuring Oil and Gas Investments – Partnerships and Joint Ventures – Income Tax Consequences – SIFT Legislation](#)).

Partnership information returns

The partners of a partnership that carries on business in Canada are required to file a federal information return. They may also be required—if the partnership conducts business in Québec—to file a Québec information return. The information return reports the partnership's income or loss and the allocation of this amount to each of the partners. The information return can be filed by one partner on behalf of all of the partners.

Federal reporting requirements

The **Regulations** prescribe that a federal information return must be filed:

- within five months after the end of the fiscal period for a partnership, all of the members of which are corporations throughout the fiscal period;
- by the end of March of the calendar year following the calendar year in which the fiscal period ended for a partnership, all of the members of which are individuals; or

- in any other case, on or before the earlier of (i) the day that is five months after the end of the fiscal period, and (ii) the last day of March in the calendar year immediately following the calendar year in which the fiscal period ended.

The CRA does not require a partnership with fewer than six partners to file a federal information return unless:

- the partnership's revenues and the absolute value of its expenses exceed \$2 million; or
- the partnership has assets of at least \$5 million; or
- the partnership has a partnership as a partner, or is a member of another partnership; or has a corporation or trust as a partner; or invested in flow-through shares of a **principal-business corporation** that renounced Canadian resource expenses to the partnership.

The CRA has reserved the right to request a partnership with fewer than six partners to file an information return in other circumstances.

Each person who holds an interest in a partnership as a nominee or agent for another person must complete and file a separate information return for each partnership in which an interest is held for another person.

Québec reporting requirements

The partners of a partnership in Canada will be required to file a Québec information return in addition to a federal one if:

- the partnership carries on business in Québec, or
- the partnership either carries on business in Canada outside Québec or is a Canadian partnership and the partnership has at least one member that is:
 - an individual (including a trust) that is resident in Québec, or
 - is a corporation that has an establishment in Québec.

A Québec information return can be filed by one partner on behalf of all of the other partners provided that the filing member is designated for the purpose of filing the information return.

The Québec information return must be attached to and filed with the fiscal return that the person or member files for that year (or for the person's or the member's taxation year in which the partnership's fiscal period ends).

On an administrative basis, the partners of a partnership do not need to file a Québec information return unless:

- at the end of the fiscal period, either:
 - the total combined absolute value of the partnership's revenues and expenses exceeded \$2 million, or

- the value of the partnership's assets exceeded \$5 million; or
- at any time during the fiscal period:
 - the partnership had more than five members,
 - either the partnership was itself a member of another partnership or one of the partnership's members was also a partnership,
 - one of the partnership's members was a trust or a corporation,
 - exploration and development expenses were renounced in favour of the partnership or amounts of assistance were allocated to the partnership, because the partnership invested in flow-through shares, or
 - the partnership was a SIFT entity and had an establishment in Québec.

Each person who holds an interest in a partnership as a mandatary or representative must complete and file a separate Québec information return for each such holding.

Joint ventures

For a **joint venture**, the participants are considered to carry on the activities of the joint venture directly. The participants are required to report the tax results of the joint venture in their own tax returns.

FUNCTIONAL CURRENCY TAX REPORTING

Qualifying Canadian corporations can elect to compute their Canadian tax results using their functional currency, rather than the Canadian dollar, for financial reporting purposes.

The functional currency election is advantageous for the following reasons:

- Corporations need not maintain Canadian-dollar books and records solely for tax purposes. This reduces the burden of compliance.
- Corporations can eliminate the distorting effect of foreign exchange gains and losses on their tax and financial results, an effect that comes from computing their Canadian tax results using the Canadian dollar.

Corporations must meet the following conditions in order to make the functional currency election:

- The corporation must be a **Canadian corporation** throughout the particular taxation year; a Canadian branch of a foreign owner is not entitled to file on this basis.
- The corporation must file the election to have the functional currency rules apply.

- The functional currency of the corporation (currently limited to the US dollar, the British pound, the Euro, and the Australian dollar) must be the primary currency in which the corporation maintains its books and records for financial reporting purposes throughout the year. This will be the same as the functional currency determined under **generally accepted accounting principles (GAAP)** or **international financial reporting standards (IFRS)**, as applicable.
- The corporation must never have previously filed a functional currency election.

In its first **functional currency year**, an electing corporation must translate its Canadian-dollar tax attributes into the functional currency, using the spot rate in effect on the last day of the preceding tax year. For debt obligations denominated in a currency other than the functional currency, the principal amount at the end of the preceding tax year must be converted using the spot rate at that time. Any unrealized foreign exchange gains and losses at the time of conversion (including on amounts denominated in the functional currency) are “locked in” and must be recognized for tax purposes on a pro-rata basis as the debt’s principal amount is paid down. A corporation should evaluate trends in currency movement to determine the optimal time to make the election.

A corporation is allowed to revoke the election and revert to using Canadian dollars. If it does so, or if it ceases to qualify as a functional currency reporter, it cannot make the election again. Also, once a corporation has made the election, it cannot subsequently switch to a different functional currency. Specific anti-avoidance rules apply to prevent corporations from circumventing this “one-time” rule by means of corporate reorganizations or asset transfers.

Canadian corporations operating in the oil and gas industry and other resource industries are obvious beneficiaries of the functional currency election. This is because the commodity markets within which they operate are conducted mostly in US dollars. The election will often allow them to align their Canadian tax computations with their financial reporting. Such alignment eliminates permanent differences arising from foreign exchange gains or losses recognized for tax purposes but not financial reporting purposes, and vice versa.



Deductions, allowances, and credits

The **ITA** and the provincial statutes provide a number of deductions, allowances, and credits that are specifically available to taxpayers engaged in qualifying oil and gas activities. These provisions apply over and above the standard deductions, allowances, and credits available to individuals and entities that are subject to tax on income earned from a business or property.

The oil and gas provisions described below are designed to encourage and support the exploitation of oil, gas, and mineral resources, by recognizing certain business challenges that are unique to this industry. A particular aspect of this planning – the tax-efficient structuring of oil and gas investments – is discussed in a separate section of this book.

CANADIAN EXPLORATION EXPENSES

The ITA provides a deduction for **Canadian exploration expenses (CEE)** incurred during the exploration stage of oil and gas activities. These deductible costs include:

- **G3 Expenses:** This category includes geological, geophysical, or geochemical expenses, as well as environmental studies or community consultations, including studies or consultations that are undertaken to obtain a right, license or privilege, incurred for the purpose of determining the existence, location, extent, or quality of an accumulation of petroleum or natural gas in Canada. These expenses are sometimes referred

to as **G3 expenses**, and they generally include expenses incurred in extracting and studying core samples, in obtaining and studying data concerning formations beneath the surface of the earth, and in chemical analysis in respect of deposits.

- **Exploratory probe expenses:** By definition, an **oil or gas well** does not include an **exploratory probe**, and all costs incurred in drilling an exploratory probe may be classified immediately as CEE. The term “exploratory probe” is not defined in the ITA, but it is generally used in the oil and gas industry to refer to a probe that is used to extract samples for test purposes.
- **Drilling Expenses:** This category currently includes expenses incurred in drilling or completing an oil or gas well in Canada or in building a temporary access road to – or preparing a site in respect of – such a well, provided that:
 - the **drilling or completion** of the well, prior to 2019, resulted in the discovery that a natural underground reservoir contained either petroleum or natural gas and the discovery occurred at any time before six months after the end of the year;
 - the well is abandoned within six months after the end of the year without ever having produced otherwise than for a specified purpose;
 - the expense is incurred during the period of 24 months after completion of the well and

the well has not produced during that period otherwise than for specified purposes; or

- the Minister of Natural Resources issues a certificate that he or she is satisfied that
 - the total of expenses incurred or to be incurred in drilling or completing the well, in building a temporary access road to the well, and in preparing the site in respect of the well will exceed \$5,000,000, and
 - the well will not produce, otherwise than for a specified purpose, within the period of 24 months commencing on the day in which the drilling of the well is completed.

The phrase *specified purpose* means (i) the operation of an oil and gas well for the sole purpose of testing the well or the wellhead and related equipment in accordance with generally accepted engineering practices, and (ii) the burning of natural gas and related hydrocarbons to protect the environment.

Expenses incurred in bringing a mine in a bituminous sands deposit into production constituted CEE until March 22, 2011, when the federal budget for the 2011–2012 fiscal year was presented to the House of Commons. That budget provided that such expenses would in the future be categorized as **Canadian Development Expenses (CDE)**, except for certain specific project expenses (**specified oil sands mine development expenses**), incurred prior to 2015, that

have been grandfathered as CEE. There is a transition period with other project expenses a portion of which (**eligible oil sands mine development expenses**) have been grandfathered as CEE through phase-in rules.

As described above, the determination of whether an expense is CEE may depend upon events which occur after the end of the year. An oil or gas drilling expense that does not satisfy the definition of CEE at the end of the taxation year in which the taxpayer incurs the expense will initially be categorized as a CDE. Such an expense may subsequently be found to meet the definition of a CEE, and it will be re-characterized accordingly at this time.

CEE excludes the costs of **depreciable property**, such as tubing and pumps (discussed in [Deductions, Allowances, and Credits – Capital Cost Allowance](#)).

A taxpayer includes its CEE in its **cumulative Canadian exploration expense (CCEE)** account.

- A **principal-business corporation** may deduct up to 100 percent of its CCEE balance at the end of the year to the extent of its income for that particular taxation year. A principal-business corporation cannot create a loss by claiming a deduction in respect of its CCEE account in excess of its income for that year.

- A taxpayer that is not a principal-business corporation may claim a deduction of up to 100 percent of its CCEE account at the end of the year without restriction. However, a deduction in excess of the taxpayer's income may have significant adverse consequences under federal, and in some cases provincial, minimum tax legislation.

A taxpayer deducts from its CCEE account any amount claimed as CEE in the year. Any balance remaining in the account can be carried forward indefinitely and deducted in future years, subject to the limitations imposed by the ITA.

CANADIAN DEVELOPMENT EXPENSES

The ITA also provides a deduction for **Canadian development expenses (CDE)** incurred in Canada in the oil and gas context.

CDE is the default category for expenses incurred in:

- drilling or completing an oil or gas well,
- building a temporary access road to the well, or
- preparing a site in respect of the well.

If an expense of this type does not qualify as a CEE, it is categorized as a CDE. If such an expense subsequently satisfies the definition of CEE, it will be reclassified as a CEE at that time.

CDE also includes other expenses related to the drilling of oil and gas wells, such as the cost of:

- drilling or converting a well for the disposal of waste liquids;
- drilling or converting a well for the injection of water, gas, or any other substance to assist in the recovery of petroleum or natural gas;
- drilling for water or gas for injection into a petroleum or natural gas formation; and
- drilling or converting a well for the purpose of monitoring fluid levels, pressure changes, or other phenomena in an accumulation of petroleum or natural gas.

CDE excludes the costs of **depreciable property**, such as well casings and pumps (discussed in [Deductions, Allowances, and Credits – Capital Cost Allowance](#)).

A taxpayer includes its CDE in its **cumulative Canadian development expense (CCDE)** account. The taxpayer may deduct up to 30 percent of the balance in a year (subject to proration for short years). The deduction that a taxpayer may claim in respect of its CCDE account is discretionary.

A taxpayer deducts from its CCDE account any amount claimed as CDE in the year. In addition, a taxpayer deducts from its CCDE account any amount

by which its **cumulative Canadian oil and gas property expense (CCOGPE)** account is negative at the end of the year (CCOGPE is discussed below). If the CCDE account is negative at the end of the year, the taxpayer includes the amount of the negative balance in its income for the year.

A taxpayer may carry forward indefinitely any *undeducted* balance in its CCDE account and claim the amount in future years, subject to the limitations imposed by the ITA.

CANADIAN OIL AND GAS PROPERTY EXPENSES

A third category of deductible expenses under the ITA is **Canadian oil and gas property expenses (COGPE)**. COGPE includes the cost of acquisition of a **Canadian resource property** that is an **oil and gas property**. This includes the cost of land, exploration rights, licenses, permits, leases, well, and a royalty interest in an oil and gas property in Canada.

Many oil sands activities are more akin to mining than they are to conventional oil and gas activities. The costs of oil sands rights, licenses, permits, and leases were formerly treated as CDE but are now classified as COGPE.

A taxpayer includes its COGPE in its cumulative **Canadian oil and gas property expense (CCOGPE)**

account. The taxpayer may deduct up to 10 percent of the balance in a year (subject to proration for short taxation years). The deduction that a taxpayer may claim in respect of its CCOGPE account is discretionary.

A taxpayer deducts from its CCOGPE account any amount claimed as COGPE in the year. If the taxpayer disposes of an oil and gas property, the disposition does not give rise to a **capital gain** or a **capital loss**; instead, the taxpayer deducts the proceeds from its CCOGPE account in that year. If the CCOGPE account is negative at the end of the year, the taxpayer deducts the negative amount from its CCDE account. If the CCDE account is negative at the end of the year, the taxpayer includes the amount of the negative balance in its income for the year.

A taxpayer may carry forward indefinitely any undeducted balance in its CCOGPE account and claim the amount in future years, subject to the limitations imposed by the ITA.

FOREIGN RESOURCE EXPENSES

A fourth category of deductible expenses under the ITA is **foreign resource expenses (FRE)**. FRE includes expenses in respect of drilling, exploration, prospecting, surveying, and acquisition costs relating to a **foreign resource property**. They do not include, among other things, the cost of **depreciable property**

and expenditures incurred after the commencement of production.

Where a taxpayer carries on business directly in one or more foreign jurisdictions in respect of a foreign resource property, and incurs FRE, those expenses are added to the taxpayer's **cumulative foreign resource expense (CFRE)** account on a country-by-country basis. The taxpayer does not claim a deduction directly in respect of any FRE; instead, it claims a deduction in respect of its **adjusted cumulative foreign resource expense (ACFRE)** account. Unlike other accounts, the CFRE is adjusted for transactions subject to the successor corporation rules – discussed below – and a taxpayer claims a deduction in respect of its ACFRE and not in respect of its CFRE. Unless a taxpayer has been involved in a transaction that is subject to the successor corporation rules, its ACFRE will be the same as its CFRE.

Where a taxpayer disposes of a foreign resource property, the taxpayer may elect to deduct the proceeds from its ACFRE account in respect of that country. If the taxpayer chooses not to make the election, it will be required to include the amount of the proceeds in income. The latter option may be preferred if the taxpayer has **foreign exploration and development expenses (FEDE)**, or **non-capital losses** that might expire in the near future, or if the taxpayer is concerned about losing foreign tax credits.

In computing its income for a taxation year, the taxpayer may claim an optional deduction of up to 10 percent of the balance in its ACFRE account for a country (subject to proration for short taxation years), whether or not it has any foreign resource income for the year from that country. The maximum deduction is equal to the lesser of 30 percent of the ACFRE for the particular country (subject to proration for short taxation years) and the foreign resource income for that country. Where the taxpayer has an ACFRE account in respect of two or more countries, the taxpayer may also claim an additional deduction so that its maximum deduction (subject to proration for short taxation years) is equal to the lesser of 30 percent of its aggregate ACFRE balances in respect of all countries and its foreign resource income from all countries in the taxation year.

SUCCESSOR CORPORATION RULES

The successor corporation rules (the **SC rules**) provide an exception to the ITA's basic scheme of restricting the deductibility of expenses to the taxpayer that incurred those expenses. The SC rules are a mixture of relieving and limiting legislation. They permit a corporation that acquires **all or substantially all** of the Canadian or foreign resource properties of another **person** to deduct any unused expenses of the transferor subject to the limitations described below. In this sense, the rules provide an exception to the ITA's basic premise that only a taxpayer that incurs

expenses may deduct them. At the same time, the SC rules impose limitations that may apply where a corporation participates in a reorganization or where a person or group of persons acquires **control** of the corporation.

The SC rules allow a purchaser (the **successor**) that acquires all or substantially all of the **Canadian resource properties** or **foreign resource properties** of a vendor (the **original owner**) to elect jointly with the vendor to treat any undeducted **resource expenses** of the vendor as successored expenses of the purchaser. The successor may apply successored expenses only against:

- income from production from, and
- proceeds of disposition of,

the properties acquired from the original owner.

Original owner

The original owner is the person who originally incurred the particular resource expense. The original owner may be an individual, a corporation, or other person. A **partnership** is not a person for the purposes of the SC rules; in addition, resource expenses are allocated to and deducted by the partners and not by the partnership (see [Structuring Oil and Gas Investments – Partnerships and Joint Ventures](#)).

The amount of qualifying expenses incurred by an original owner that are available to a successor in a taxation year are:

- the aggregate of such expenses that were incurred by the original owner before it disposed of the particular property

less

- the amount of such expenses
 - deducted by the original owner,
 - deducted by any **predecessor owner** of the particular property, and
 - deducted by the successor in computing its income for a preceding year.

Successor

A corporation that is entitled under the SC rules to deduct the expenses of another person is referred to as a successor. Only a corporation may be a successor. There is no requirement that a successor corporation be a **Canadian corporation**.

With respect to acquisitions of Canadian resource properties, a successor may claim the maximum allowable deduction in respect of CEE (up to 100 percent), CDE (30 percent per annum on a declining balance basis), and COGPE (up to 10 percent on a declining balance basis) if it has sufficient income

from production or proceeds of disposition from the acquired properties to use those deductions. Any proceeds of disposition are deducted from and reduce the appropriate CCDE and CCOGPE accounts of the original owner that the successor corporation may deduct.

Similar rules apply to acquisitions of foreign resource properties; however, they may operate independently from the rules relating to Canadian resource properties.

Predecessor owner

One of the complications of the SC rules is that they contemplate an infinite number of transfers and, therefore, an infinite number of successors. The link or links between the original owner that incurs resource expenses and the successor that may deduct the expenses is a **predecessor owner**.

A predecessor owner of a **resource property** is a corporation that:

- acquired the property in circumstances in which the SC rules apply;
- disposed of the property in circumstances in which the rules apply; and
- but for the application of the rules, would have been entitled to deduct resource expenses incurred by an original owner of the property against income from production from, or proceeds of disposition of,

the property in computing its income for a taxation year after it disposed of the property.

A corporation may be an original owner in connection with resource expenses that it incurred in respect of a property and may be a predecessor owner with respect to resource expenses that previous original owners of that property incurred. Example 1 illustrates this concept.

Provided that the property has been transferred from one person to another in accordance with the SC rules, the successor that owns the property in a taxation year may claim the resource expenses incurred by each original owner against income from the property.

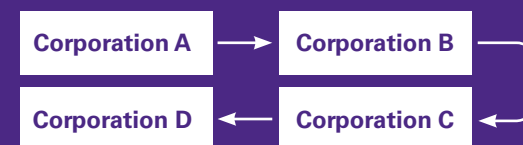
The SC rules work on a “pool” concept. They look at all of an original owner’s expenses and the properties that it owns at the time it disposes of the properties in accordance with the rules. The SC rules do not track the expenditures to a particular property.

Suppose that, in Example 1, Corporation A owned 10 Canadian resource properties (properties 1 through 10) but incurred resource expenses only on properties 1 through 5. If Corporation A transferred properties 1 through 10 to Corporation B in a transaction that satisfied the SC rules, Corporation B could deduct any expenses of Corporation A against income from all of properties 1 through 10, even though Corporation A did not incur any expenses on properties 6 through 10.

EXAMPLE 1

Expenses deductible to a predecessor owner and a successor

In the sequence of transactions illustrated below, Corporation A transfers resource properties to Corporation B in accordance with the SC rules; Corporation B transfers resource properties to Corporation C in accordance with the SC rules; and Corporation C transfers resource properties to Corporation D in accordance with the SC rules.



- Each of Corporations A, B, and C is an original owner with respect to any expenses that it incurs on the properties.
- Each of Corporations B and C is a predecessor owner with respect to any expenses that Corporation A incurred on the properties.
- Corporation C is a predecessor owner with respect to any expenses incurred by Corporation B on the properties.
- Corporation D is the successor with respect to the expenses that Corporations A, B, and C incurred on the properties.

Suppose that Corporation B purchased property 11 and incurred expenses on that property, but did not incur expenses on properties 1 through 10. Suppose, further, that Corporation B sold properties 1 through 5 and property 11 in transactions that were not subject to the SC rules (because they did not constitute the sale of all or substantially all of Corporation B's Canadian resource properties) and then sold properties 6 through 10 to Corporation C in a transaction that was subject to the SC rules. Corporation C could deduct the SC expenses of Corporation A against income from properties 6 through 10 notwithstanding that Corporation A had not incurred any of those expenses on those properties. Corporation C could also deduct any undeducted expenses of Corporation B that Corporation B had incurred on property 11 against income from properties 6 through 10, even though Corporation B had not incurred any expenses on those properties.

Amalgamations

Where there is an **amalgamation** of two or more corporations, the new corporation is a successor to each of its predecessor corporations, and the SC rules apply to the deduction by the new corporation of the resource-related expenses of each of the predecessor corporations. There is an exception to this rule where there is an amalgamation of a corporation and one or more of its subsidiary wholly owned corporations, or an amalgamation of two or more corporations each

of which is a subsidiary wholly owned corporation of the same person. In such circumstances, the new corporation is deemed to be the same corporation as, and a continuation of, each amalgamating corporation.

For these purposes, a subsidiary wholly owned corporation of a person ("the parent") is a corporation all of whose issued and outstanding shares belong to the parent, to a corporation that is itself a subsidiary wholly owned corporation of the parent, or to any combination of persons each of which is a parent or a subsidiary wholly owned corporation of the parent.

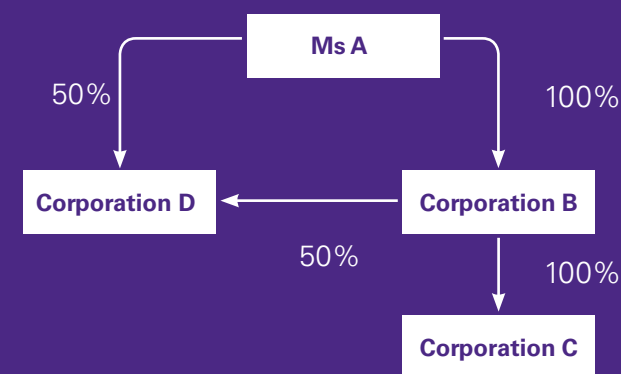
Since "person" includes a reference to an individual and not just to a parent corporation, a corporation can be a subsidiary wholly owned corporation of an individual. Consequently, an amalgamation of two or more corporations, all of the shares of each of which are owned by the same individual, will satisfy the conditions for the exception. Example 2 illustrates such a situation.

Where the exception applies, the new corporation may deduct the expenses of a predecessor corporation on the same basis as each of the predecessor corporations deducted these expenses. Since the successor corporation rules apply to an amalgamation unless the exception applies, it is advisable for the successor corporation, if possible, to implement a corporate reorganization so that it is an amalgamation that qualifies for the exception.

EXAMPLE 2

Structure allowing for a qualifying amalgamation of wholly owned subsidiaries

Ms A owns all of the outstanding shares of Corporation B; Corporation B owns all of the outstanding shares of Corporation C; and each of Ms A and Corporation B owns 50 percent of the outstanding shares of Corporation D. The corporate organization is as follows:



- Ms A is the "parent."
- Corporation B is a subsidiary wholly owned corporation of Ms A.
- Corporation C is a subsidiary wholly owned corporation of Ms A.
- Corporation D is a subsidiary wholly owned corporation of Ms A.
- Corporation C is a wholly owned subsidiary of Corporation B.

Since all of the corporations are subsidiary wholly owned corporations of Ms A, any amalgamation of two or more of the corporations will satisfy the conditions for the exception to apply and will not be subject to the limitations of the SC rules.

Wind-ups

The ITA permits a tax-deferred wind-up of a Canadian subsidiary into its parent where certain conditions are met (as discussed later in [Structuring Oil and Gas Investments – Corporate Reorganizations](#)).

Where a parent winds up a subsidiary corporation in accordance with the tax-deferral rules, the parent is deemed to be the same corporation as, and a continuation of, the subsidiary. As a result, the parent can claim the resource-related deductions of the subsidiary under the SC rules. Even if the subsidiary's own resource-related expenses at the time of winding up exceed the fair market value of the resource properties of the subsidiary, the parent will be entitled to deduct the full amount of those expenses.

Where a corporation is wound up and the tax-deferral rules do not apply, the wound-up corporation is deemed to have distributed all of its resource properties at their fair market value. If it is possible for the wound-up corporation to transfer all or substantially all of its Canadian or foreign resource properties to one corporation, then that person could be a successor corporation to the wound-up corporation.

Acquisition of control

The SC rules apply on an acquisition of control of a corporation to treat the corporation as a successor to itself. As a result, the corporation is in the same

position that it would have been in if it had acquired all of its property from another corporation with the same resource expenses and properties, which it had owned immediately prior to the acquisition of control, and it had elected to have the SC rules apply.

The ITA contains relieving provisions that provide for exceptions to the effect of the SC rules on an acquisition of control of a corporation.

Designations among corporations

A “transferor corporation” may make a designation in respect of its income from resource properties owned by it immediately before an acquisition of control in favour of a “transferee corporation” for any taxation year ending after the acquisition of control. The transferee must be either the parent corporation or a subsidiary wholly owned corporation of the transferor corporation or of a corporation that is a wholly owned subsidiary of the person who is a parent of the transferor corporation throughout the taxation year.

The transferee may use the designated income to compute the amount of the deduction that it is entitled to claim in respect of the successored resource expenses that it incurred while it was a parent or subsidiary wholly owned corporation of the transferor. This designation is advantageous in a situation where one member of a corporate group had resource expenses but no property prior to an acquisition of control. The designation causes income that is from a resource property to lose that

character to the transferor corporation and to cause income of the transferee to take on that character. The designation does not cause income of the transferor to become income of the transferee's partnership income.

When a partnership owns **resource property**, a partner of the partnership does not have an interest in that property as a result of having an interest in the partnership. In addition, a partnership cannot deduct any resource expenses that it incurs, but instead allocates those expenses to the partners at the end of the taxation year of the partnership. But for specific relieving provisions in the SC rules, a corporation could not apply any of its **resource expenses** existing immediately prior to an acquisition of control against income from and proceeds of disposition of resource properties owned by a partnership in which it had an interest immediately prior to the acquisition of control.

The relieving provision treats the corporation as having owned, immediately before the acquisition of control, a portion of the resource property owned by the partnership at the time of the acquisition of control equal to its percentage share of the aggregate of amounts that would be paid to all members of the partnership if it were wound up at that time.

In addition, for taxation years ending after the acquisition of control, a partner's share of the income of the partnership is deemed to be income of the corporation for the year attributable to production from

the property. The corporate partner's share of income of the partnership for such purposes is the lesser of its share otherwise determined and the amount that would be its share of the income of the partnership if that share were determined on the basis of the corporate partner's percentage entitlement to the property of the partnership on a wind-up of the partnership.

A similar issue arises where there is an amalgamation of corporations that are not subsidiary wholly owned corporations of a person, and one of the corporations is a partner of a partnership. In this situation, the amalgamated corporation is entitled to a similar relieving provision.

CAPITAL COST ALLOWANCE

Calculation of capital cost allowance

The **capital cost allowance (CCA)** provisions in the ITA allow a taxpayer to claim an annual deduction in respect of **depreciable property** owned at the end of the taxation year. Each depreciable property is allocated to a class, and the amount of the deduction varies according to the class in which the property belongs. For most classes, the CCA deduction that may be claimed in a particular year is calculated on a declining balance basis. Any balance remaining in the particular class at the end of a taxation year is referred to as **undepreciated capital cost (UCC)** and represents the opening balance for the following taxation year.

The UCC balance for each class is adjusted each year to reflect any acquisitions or dispositions of property in that class. For acquisitions, the balance is increased by the net cost of additions in the year; however, for some classes, a "half-year rule" applies that limits the increase in the year of acquisition to one-half of the net cost for purposes of computing CCA for that year. For dispositions, the UCC balance is reduced by the lesser of the proceeds of disposition and the original capital cost of the property.

The capital cost of a property for the purposes of calculating CCA may be reduced by the amount of any assistance that the taxpayer receives or is entitled to receive from a government, municipality, or public authority in respect of or for the acquisition of the property, less any amount of such assistance that the taxpayer has repaid. **Investment tax credits** claimed in respect of a particular property will also reduce the UCC.

An asset is not added to a particular class, and CCA cannot be claimed, until the asset is available for use. An asset is considered available for use when it is first used for an income-earning purpose. However, available for use rules allow for earlier claims by allowing CCA to be claimed in the taxation year that is the earlier of the year that includes the period ending 24 months after the property is acquired and the year during which the property is available for use in the conduct of the taxpayer's business.

Classification

Generally, when it comes to oil and gas well costs, UCC is distinguished from resource accounts such as CEE, CDE, and COGPE. The difference is that UCC is considered a tangible cost, whereas resource accounts are intangible costs. Typically, all expenditures below the surface that are not removable or transferable, including **casing**, are considered intangible costs, whereas the expenditures above ground that can be moved to another well site location are considered tangible costs.

There are relatively few CCA classes that are particularly relevant to the oil and gas industry. Most oil and gas equipment is included in Class 41. Class 41 includes the tangible costs associated with the drilling or exploring for oil and gas wells, such as exploration and drilling equipment, gas or oil well equipment, and property used in Canadian field processing. Examples of these types of costs are **wellheads, downhole pumps, production tubing, compressors, and gathering systems** (also called **gathering lines**). The CCA rate for Class 41 is 25 percent. Another class relevant to the oil and gas industry is Class 43, which consists primarily of manufacturing and processing property. Class 43 normally relates to plant facilities such as **straddle plants** and **fractionation plants**. The CCA rate for Class 43 is 30 percent.

Pipelines

The UCC class to which costs associated with pipelines belong depend upon the type of pipeline. The cost of some pipelines (e.g., gathering lines) may be classified as Class 41, but the costs of others may be included in Class 1, Class 8, or Class 49. Pipelines whose costs belong to Class 1 are pipelines used for the distribution of petroleum and natural gas or related hydrocarbons, as well as pipelines from a gas-processing plant to the transmission line or loading facilities for product sales lines. Class 49 would include the costs of pipeline used for the transmission but not distribution of petroleum, natural gas, or related hydrocarbons. Class 8 is a distinct category; it includes the costs of pipeline whose main source of supply – in the estimation of the CRA, in consultation with the Minister of Natural Resources – is likely to be exhausted within 15 years of its becoming operational. The CCA rates for Class 1, 8, and 49 are 4 percent, 20 percent, and 8 percent, respectively.

FLOW-THROUGH SHARES

The **flow-through share** provisions are an exception to the basic scheme of the ITA providing that only the taxpayer that incurs an expense may deduct the expense.

The concept of a flow-through share is that an investor enters into an agreement with a principal-business

corporation to subscribe for shares of the corporation, and the corporation uses the subscription funds to incur **qualifying CEE** or **qualifying CDE**, which it then renounces to the investor. In most arm's length situations, an investor will want only CEE, because of the rapid write-off available for these expenses in contrast to the comparatively slow write-off for CDE. Therefore, in most arm's length agreements between corporations and investors, the corporation will warrant that it will incur CEE and renounce those expenses to the investor.

For purposes of the flow-through share rules, some CDE incurred, prior to 2019, by corporations that have taxable capital of not more than \$15,000,000 will be considered CEE; such CDE is referred to as "deemed CEE." For these purposes, taxable capital of a corporation includes the taxable capital of associated corporations.

For a share of a corporation to be a flow-through share, it must:

- be a share or a right to acquire a share of a principal-business corporation;
- not be a prescribed share or a prescribed right; and
- be issued by the corporation to an investor pursuant to an agreement in writing under which the corporation agrees to incur CEE or CDE and to renounce such expenses to the investor.

It is not clear from this definition precisely when the corporation must qualify as a principal-business corporation. Therefore, for certainty, the agreement with the investor will require the corporation to warrant that it will be a principal-business corporation at all relevant times and that it will provide an indemnity to the investor if the investor is not entitled to the expenses renounced by the corporation.

The flow-through share concept is a tax concept, not a corporate concept. There is nothing in the corporate constating documents that would indicate that a share is a flow-through share. A share will be a flow-through share only to the **person** that enters into the agreement with the corporation, and not to any subsequent purchaser. Provided that a share is not a prescribed share (as determined under the **Regulations**), the share can have any attributes that the corporation and the investor choose. However, the Regulations are so detailed and restrictive that, effectively, only voting and non-voting common shares can be flow-through shares.

The corporation can renounce only the qualifying expenses incurred during the period commencing on the day the agreement is entered into and ending 24 months after the end of the month that includes that day. Investors in public transactions will typically require that the corporation renounce the expenses for the year in which the investor subscribes for

shares. The amount of CEE or CDE renounced to the investor is limited to the amount that the investor paid for the shares.

Although it is not necessary that the investor contribute its subscription proceeds to the corporation at the time the agreement is entered into, the subscription proceeds must be advanced before the corporation may issue the shares.

A corporation may not renounce as CEE or CDE:

- the cost of certain forms of seismic data including seismic data not incurred by the corporation; and
- CEE or CDE that is a **Canadian exploration and development overhead expense (CEDOE)**.

The CEDOE category anticipates that there are some expenses that might be defined as CEE or CDE but that are akin to operating expenses and should not afford a taxpayer the additional benefits that the taxpayer may realize if the expenses are defined as CEE or CDE.

Where a corporation renounces CEE or CDE to an investor, the investor is deemed to have incurred those expenses and, except for the purposes of the renunciation, the corporation is deemed never to have incurred the expenses.

The look-back rule

The look-back rule permits a corporation that incurs certain forms of **CEE** or **CDE** in a calendar year to renounce those expenses to an investor effective December 31 of the previous calendar year. The expenses are then considered to have been incurred by the investor in that previous calendar year.

For the look-back rule to apply to an expense:

- the agreement must have been made in the calendar year preceding the year in which the expense is incurred;
- the investor must have paid the consideration for the share in that preceding calendar year; and
- the corporation and investor must deal with each other at arm's length.

The effect of the look-back rule is to accelerate the deduction of CEE or CDE renounced to the investor. To compensate the federal government for the potential loss of tax revenue, the corporation is subject to an additional tax under Part XII.6 of the ITA. A summary of the Part XII.6 rules is provided in the box on the right.

PART XII.6 TAX: SUMMARY OF THE RULES

Application

As a result of the look-back rule, where a corporation renounces certain forms of CEE in a particular calendar year, the investor is deemed to have incurred the expenses in the preceding year and is entitled to deduct them in computing the tax payable for that year. The corporation, however, is required to incur expenses only before the end of the calendar year in which the renunciation is made. This difference in timing potentially results in a loss of tax revenue to the government, from the tax savings to the investor and the deferral of expenditures by the corporation. Part XII.6 therefore imposes a tax on the corporation, to compensate the government for the acceleration of the deduction provided to the investor.

Calculation of tax

Tax is payable for each month after January of the calendar year in which the renunciation is made and at the end of which all the expenses have not been incurred. The tax for a month is the product of:

- the amount of the expenses that have not yet been incurred by the end of the relevant month multiplied by
- the quotient obtained by dividing the prescribed rate of interest by 12.

In addition, if the corporation has failed to incur the renounced expenses by the end of the year, the corporation is liable to pay a tax in an amount equal to 10 percent of the unspent amount.

Stacking arrangements

A stacking arrangement allows a public corporation to renounce CEE or CDE incurred by a subsidiary where the parent and the subsidiary are both **principal-business corporations**. In a stacking arrangement, the parent issues flow-through shares to the public, and the subsidiary issues flow-through shares to the parent. The subsidiary incurs **resource expenses** and renounces those resource expenses to the parent. The parent then renounces to the purchasers of its flow-through shares the expenses incurred by the subsidiary and renounced to the parent.

The look-back rule permits a subsidiary to renounce qualifying CEE (including deemed CEE) to the parent in one year, which the parent can in turn renounce to the purchasers of its flow-through shares effective the previous year.

The parent may renounce expenses to its investors based on the look-back rule, but the subsidiary may only renounce to its parent after the expenditures are made (i.e., in accordance with the general rules).

Use of a limited partnership

A **limited partnership** is often used to subscribe for flow-through shares in a number of different corporations. For the purposes of the flow-through share rules, a partnership is a person.

In a typical transaction after the partnership has allocated the CEE or CDE, it transfers the shares on a tax-deferred basis to a corporation that qualifies as a mutual fund corporation. The partnership is then dissolved, also on a tax-deferred basis. From the viewpoint of an investor, one advantage of this arrangement is increased liquidity in respect of the investment. Another is that the investor's risk is spread over several share issues instead of being concentrated in a single issue.

Dispositions of flow-through shares

The cost of a flow-through share to an investor is deemed to be nil regardless of whether the corporation has actually renounced the qualifying expenditures. In most circumstances, flow-through shares will be considered capital property to the investor. Accordingly, the investor will realize a **capital gain** on disposition equal to the full proceeds from the sale of the shares.

Advantages and limitations of flow-through shares

For the investor

Advantages

An investor is entitled to deduct from its income renounced CEE or CDE equal to the full amount it paid for the flow-through shares. As a result, the

cost of the shares on an after-tax basis will be less than the cost of similar shares acquired on an ordinary subscription basis.

Limitations

There are no particular income tax disadvantages to an investor that acquires flow-through shares; however, under securities legislation, it may be necessary for the investor (that is, the original purchaser of the shares) to hold the shares for a particular period of time. As a result, if the shares start to decline in value, the investor may not be able to dispose of them immediately and limit the loss. If an individual or trust acquires these shares, alternative minimum tax may apply. This is a base amount of tax that these persons must pay in a given year. It is creditable against future income taxes owing in the following seven taxation years subject to the limitations provided by the rules in the ITA.



For the corporation

Advantages

Because of the tax savings available to the investor from the deduction of the renounced expenses, flow-through shares can be issued at a premium over the subscription price for ordinary shares of the corporation. The amount of the premium will depend upon market forces. There is less dilution as a result of the issuance of flow-through shares.

Limitations

A corporation is not entitled to renounce expenses other than CEE or CDE. This restriction limits the utility of flow-through shares, since a portion of any funds used in the oil and gas industry will be used to acquire **depreciable property**. In addition, flow-through shares cannot be issued to raise funds for general corporate purposes. To overcome these disadvantages, a corporation will frequently issue a unit consisting of a flow-through share and an ordinary common share. The corporation can then use the proceeds from the ordinary share portion for general corporate purposes and to acquire depreciable property.

The flow-through share provisions of the ITA do not require the tracing of the subscription funds; the provisions simply limit the amount renounced to the investors to the subscription amount of the flow-through shares.

There is also a potential tax cost to the issuance of flow-through shares, since the corporation is giving up deductions to which it would otherwise be entitled. The corporation must therefore consider whether the premium paid on the shares is sufficient to outweigh the increased incidence of tax resulting from the renunciation of CEE or CDE.

INVESTMENT TAX CREDITS

A taxpayer is entitled to a federal or provincial **investment tax credit (ITC)** when it incurs specified expenditures. A taxpayer may deduct ITCs against its tax payable. A dollar of ITC will reduce a taxpayer's tax payable by one dollar, whereas a dollar of deduction will reduce the tax payable only by one dollar multiplied by the tax rate; therefore, a dollar of ITC is more valuable than a dollar of deduction. In very limited circumstances, the ITA allows taxpayers to obtain cash payment for ITCs.

Any provincial tax credits reduce the amount of the federal tax credits.

A taxpayer may carry forward federal unused ITCs for 20 years.

Scientific research and experimental development credit

The scientific research and experimental development (**SR&ED**) program is designed to encourage Canadian

companies to conduct research and development (**R&D**) activities in Canada that will lead to new, improved, or technologically advanced products or processes. The SR&ED program provides tax incentives in the form of deductions in computing income and ITCs, which are based on the amount of expenditures incurred on eligible R&D activities.

Eligible SR&ED expenditures may include wages, materials, some overhead, and third-party R&D contracts. Only 80 percent of contract and third-party payments for SR&ED expenditures are eligible for ITCs, and eligible expenditures will not include capital expenditures.

Corporations (other than **Canadian-controlled private corporations (CCPCs)**) that incur eligible SR&ED expenditures may claim a non-refundable federal ITC equal to 15 percent. Corporations that are CCPCs are entitled to ITCs of up to 35 percent and are entitled to a refund of all or a portion of the credit.

Provincial R&D tax credits may also be available ranging from 3.5 percent in Ontario to 30 percent in Québec.

A taxpayer may carry forward unused federal ITCs for 20 years and carry back such federal ITCs for three years.

The SR&ED program covers technological projects carried out with the objective of creating or improving materials, devices, products, or processes, or solving

problems of a technical nature, provided that they meet all of the following criteria:

- *Scientific or technological advancement.* The activity is carried out to create a new product or a new process or to improve an existing product or process, and the activity must generate information that brings a scientific or technological advancement to the business.
- *Scientific or technological uncertainties.* Based on generally available scientific or technological knowledge or experience, it is not known whether a given result or objective can be achieved, or how to achieve it.
- *Scientific or technological content.* There must be evidence that qualified personnel with relevant experience in science, technology, or engineering have conducted a systematic investigation through means of experimentation or analysis.

In the resource industry, eligible projects can include the development of new petroleum recovery processes such as **enhanced steam assisted gravity drainage (E-SAGD)** or **vapour extraction (VAPEX)**. In the oil sands surface mining operations, potential projects include **bitumen** extraction, bitumen/sand **separation, tailing pond** clean up, bitumen upgrading, and water treatment and clean up. New product development, such as drilling and pumping

technologies and information technology, may be eligible projects.

The success or failure of the R&D activities is not important in determining whether the work undertaken is eligible for SR&ED ITCs.

To make an SR&ED claim, it is necessary to maintain documentation to show that the work undertaken meets the three criteria above.

Atlantic investment tax credit

A taxpayer is entitled to a 10 percent ITC on the cost of qualified resource property (i.e., investments in new buildings, machinery, and equipment) acquired for use in the Atlantic Provinces, the Gaspé Peninsula, or a prescribed offshore region. However, this ITC is being phased out.

Under grandfathering provisions, expenses incurred before 2017 for qualified resource property may earn ITCs at the rate of 10 percent if they are incurred in respect of qualified resource property acquired:

- under a written agreement entered into before March 29, 2012; or
- as part of a phase of a project if construction or engineering and design work were started before March 29, 2012.

Phase-in provisions also have been introduced for the implementation of the new rules. The specified percentage applicable to qualified resource property that is not grandfathered is:

- 10 percent if the property is acquired after March 28, 2012 and before 2014;
- 5 percent in 2014 and 2015; and
- 0 percent after 2015.

Grandfathering provisions may apply in certain circumstances.

QUALIFYING ENVIRONMENTAL TRUSTS

A taxpayer may deduct reclamation expenses in respect of a pipeline or mining property only at the time the expense is actually incurred. Historically, this has been after the pipeline or mine has ceased operations and is no longer generating income. Consequently, taxpayers in these industries have often been placed in a position where they have no income against which to deduct the reclamation expense. The qualifying environmental trust (QET) provisions of the ITA (and some provincial statutes) provide a mechanism allowing a taxpayer to set aside funds for future reclamation obligations and obtain a current deduction for the amount set aside.

The sole purpose of a QET must be for funding the reclamation of a site in Canada that had been used primarily for, or for any combination of:

- the operation of a mine;
- pipeline abandonment;
- the extraction of clay, peat, sand, shale, or aggregates (including dimension stone and gravel); or
- the deposit of waste.

The following is a summary of the QET rules:

- A taxpayer is entitled to a deduction for an amount contributed to a QET. There is no limitation on the amount that a taxpayer may contribute to a QET.
- Income earned in the QET is taxed at the trust level. However, the beneficiary is also required to report the income as if it had been earned directly, subject to the receipt of a refundable credit for tax already paid by the trust.
- When funds are withdrawn from a QET, the beneficiary is required to include amounts received from the QET in computing its income. However, there should be an offsetting deduction for reclamation costs actually incurred.
- A taxpayer is entitled to deduct consideration paid for the acquisition of an interest as a beneficiary

under a QET, excluding consideration that is the assumption of a reclamation obligation in respect of the trust.

- A taxpayer is required to include in income the total of all amounts received for the disposition of the taxpayer's interest as a beneficiary under a trust, excluding consideration received that is the assumption of a reclamation obligation in respect of a trust.

To qualify as a QET, the trust may invest only in qualified investments.

QET do not apply to oil and gas operations, excluding pipelines. One could argue that QET is not necessary for these operations because oil and gas producers continually reclaim oil and gas wells throughout their normal operations, so there is little concern that reclamation costs will become orphaned due to timing issues.

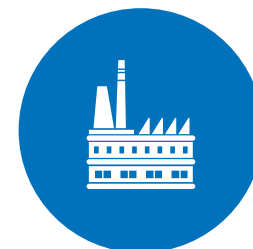
PROVINCIAL CREDITS AND ADJUSTMENTS

Flow-through shares – Québec

An investor who is an individual resident in Québec may be entitled to a 20 percent deduction in respect of Québec oil and gas exploration in addition to the basic deduction of 100 percent for CEE.

From a corporate perspective, where an eligible corporation incurs expenses that qualify as flow-through expenditures and does not renounce these expenditures to an investor, the corporation can instead claim a refundable resource tax credit. The refundable credit can range from 18.75 percent to 38.75 percent. The credit is treated as a payment by the corporation on account of its tax payable for the year. Therefore, the credit is applied first against any taxes owing for that year, and any excess is refunded to the corporation.

Expenses renounced to shareholders cannot qualify for this resource tax credit. However, if the shareholders subscribing to the flow-through shares are non-residents of Québec, it may be beneficial for the corporation to claim the resource tax credit instead.



Ontario resource allowance adjustment

Prior to May 7, 1974, **royalties** and taxes paid by a corporation to a provincial government in respect of the extraction of natural resources were deductible in computing income for the purposes of the ITA. In 1974, in response to soaring commodity prices, provincial governments substantially increased their royalties and taxes. This had the effect of substantially reducing the federal tax base. The federal government initially reacted by disallowing the deduction of provincial royalties and taxes and providing for an abatement. It subsequently replaced the abatement with the resource allowance, effective January 1, 1976. The resource allowance was 25 percent of resource profits as computed under the **Regulations**.

The federal government reversed its policy in 2002. It removed the resource allowance from the ITA and again allowed a federal deduction for provincial resource royalties and taxes. The resource allowance was phased out and ceased to be applicable after 2006.

At the time, Ontario had its own corporate tax legislation. It also had a policy of providing tax incentives and preferences to stimulate the development of the province's mining resources.

Ontario therefore chose not to adopt the new federal regime, but continued to allow the resource allowance for provincial purposes.

The harmonization of legislation required that income for the purposes of the Ontario legislation be the same as income under the ITA. However, Ontario wanted to maintain its distinct treatment of its resource industry. As a result, the harmonization legislation provides for additional tax and additional credits to put the taxpayer in the same position that it would have been in if the federal government had made no change to the resource allowance. Where the provincial taxes or royalties are greater than the resource allowance to which the taxpayer would have been entitled, the taxpayer must pay additional tax. Where the resource allowance is greater than the provincial taxes or royalties, the taxpayer is entitled to a credit. The amount of tax or credit depends upon the Ontario rate of tax and the portion of income allocable to Ontario. Credits not used in a year may be carried forward and applied in other years.

Ontario currently has very little oil and gas production. The Ontario Resource Allowance Adjustment was designed primarily for taxpayers engaged in

mining activities in Ontario. However, the resource allowance is computed under regulations similar to the regulations under the ITA as they applied prior to 2007. The current Ontario regulations apply to both mining and oil and gas activities in Canada. A taxpayer with a permanent establishment in Ontario and income allocated to Ontario would be subject to the Ontario Resource Allowance Allocation on income earned both from mining and from oil and gas activities throughout Canada.



Structuring oil and gas investments

A key decision for investors in the oil and gas industry is what structures to use for holding resource properties, for carrying out exploration and development activities, and for conducting oil and gas operations.

In Canada, the structures most commonly used for these activities are corporations, **partnerships**, and **joint ventures**. For direct investments in projects or operations outside Canada, Canadian residents can choose to operate through a branch of a Canadian corporation or through a foreign-incorporated subsidiary; similar options are available to non-residents investing directly in Canadian oil and gas operations. Alternatively, investments can be made indirectly through the purchase of interests in partnerships or shares in holding corporations. (While trusts are also an option, they lack the flexibility and tax advantages of other structures).

What structure is chosen will depend on the investor's objectives, including the desired return, the intended duration of the investment, and whether the investor seeks a controlling or a minority interest. The tax advantages afforded by a particular structure are also relevant to the decision. For example, there may be opportunities to defer or reduce Canadian tax liabilities by reorganizing **resource property** holdings or transferring assets to more tax-favoured entities. In the case of foreign property holdings, tax benefits may be available for certain holding arrangements or transactions under an applicable tax treaty.

This section highlights some tax-planning strategies that might be considered by Canadian residents and non-residents in structuring their oil and gas investments.

CORPORATE REORGANIZATIONS

The **ITA** contains rules related to tax-deferred corporate reorganizations that are applicable to all industries. However, certain aspects of these rules are particular to corporations carrying on an oil and gas business. In some circumstances, the rules limit the type or flexibility of reorganizations available to such corporations. One example is the successor corporation rules, discussed earlier, which may limit the deductibility of **resource expenses** of a corporation after a corporate reorganization (as discussed in [Deductions, Allowances, and Credits – Successor Corporation Rules](#)).

In other circumstances, the rules provide planning opportunities or greater flexibility in restructuring resource property holdings within a corporate group. In the case of corporate reorganizations involving resource properties held at the partnership level, the **ITA** provides that resource tax accounts are to be computed at the partner level, with the result that resource expenditures incurred by a partnership are automatically flowed out to partners at the end of the fiscal period of the partnership. This is in contrast to the treatment of **UCC** balances, which are computed at the partnership level.

Tax-deferred transfers

Where a taxpayer transfers an **eligible property** to a taxable Canadian corporation for consideration that includes shares of the corporation, the transferor and the corporation may jointly elect under the **ITA** an amount ("the elected amount") that is then deemed to be the transferor's proceeds of disposition and the corporation's cost of the property. Similar rules apply to the transfer of an eligible property by a partnership to a corporation. For the purpose of these provisions, an eligible property includes a **Canadian resource property** and a **foreign resource property**.

Elected amount

The elected amount cannot:

- exceed the fair market value of the property transferred
- or
- be less than the fair market value of the non-share consideration (i.e., received by the transferor on the transfer).

The elected amount also cannot be less than the lesser of the tax cost of the transferred property and the fair market value of the property.

Usually the transferor and transferee will elect an amount that will not result in an income inclusion for the transferor. For example, where the property

transferred is a **non-depreciable capital property**, the elected amount will usually be the **adjusted cost base** of the property. A **resource property** has no cost associated with it since its cost is added to the relevant account of the transferor. As a result, the parties may elect nominal proceeds where there is no non-share consideration.

In a straightforward situation, the elected amount in connection with a transfer of a Canadian **oil and gas property** will be a nominal amount. However if a higher amount is desired, the elected amount will not exceed the aggregate of the **CCEE**, **CCDE**, and **CCOGPE** accounts of the transferor.

Amalgamations

Federal and provincial corporate statutes provide rules that apply where two or more corporations amalgamate to become one. Under such legislation, the amalgamating corporations are treated like tributaries that flow together to form a single river; there is no concept of a surviving corporation. The amalgamation will be a tax-deferred event for both the corporations and their shareholders provided that:

- all of the property of the amalgamating corporations becomes property of the new corporation;
- all of the liabilities of the amalgamating corporations become liabilities of the new corporation; and

- all of the shareholders of the amalgamating corporations receive shares of the new corporation.

The successor corporation rules may apply on an amalgamation (as discussed in [Deductions, Allowances, and Credits – Successor Corporation Rules](#)).

Wind-ups of subsidiaries

Tax-deferred wind-ups

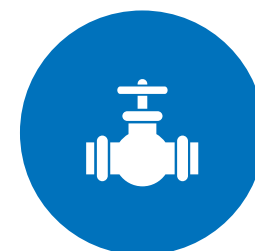
A tax-deferred wind-up of a Canadian subsidiary corporation into its parent is permitted under the ITA where:

- the parent is a taxable Canadian corporation and owns at least 90 percent of each class of shares of the subsidiary corporation;
- the subsidiary is a taxable Canadian corporation; and
- all of the shares of the subsidiary that are not owned by the parent immediately before the wind-up are owned at that time by **persons** with whom the parent was dealing at arm's length.

In practice, the parent typically owns 100 percent of the shares of the subsidiary.

Where the tax-deferral rules apply, the subsidiary is considered to have disposed of, and the parent is deemed to have acquired for nil proceeds, each

Canadian resource property and each foreign resource property distributed by the subsidiary to the parent on the winding-up. As a result, where all of the resource properties of the subsidiary are transferred to the parent, there is no reduction in the resource-related accounts of the subsidiary and no addition to the resource-related accounts of the parent. However, for the purposes of computing resource deductions, the parent is deemed to be a continuation of the subsidiary and can deduct the subsidiary's resource deductions. If any Canadian resource properties or foreign resource properties are transferred to minority shareholders, those properties are considered to have been disposed of by the subsidiary and acquired by the shareholders at their fair market value. Such a disposition will result in a reduction of the relevant accounts of the subsidiary and an increase in the relevant accounts of the minority shareholders (as discussed in [Deductions, Allowances, and Credits – Successor Corporation Rules](#)).



Other wind-ups

If the tax-deferral rules do not apply to the wind-up of a corporation, the wound-up corporation is deemed to have distributed all of its resource properties at their fair market value. As a result, there will be a reduction in the resource-related accounts of the corporation, and the corporation may realize income. There will also be a corresponding increase in the resource-related accounts of the shareholders of the corporation.

If it is possible for the wound-up corporation to transfer **all or substantially all** of its Canadian or foreign resource properties to one corporation, then that person could be a successor corporation to the wound-up corporation. The successor corporation rules may apply on a wind-up (as discussed in [Deductions, Allowances, and Credits – Successor Corporation Rules](#)).

Election to bump cost of acquired property

Where a parent winds up a subsidiary corporation under the tax-deferral rules or a parent corporation amalgamates with one or more wholly owned subsidiary corporations, the parent or the amalgamated corporation may elect to step up or “bump” the cost of non-depreciable capital property of the subsidiary. Property that is eligible for the bump includes land, shares of subsidiary corporations, and partnership interests.

The cost of the bumped property cannot be increased to more than the fair market value of the property at the time the parent last acquired **control** of the subsidiary. The total amount by which the cost of all the properties can be increased (the “bump room”) is the amount by which the cost of the shares of the subsidiary to the parent exceeds the net cost of all the assets to the subsidiary. The bump room may be restricted for the following types of property of the subsidiary:

- A partnership interest, to the extent that the fair market value of that interest is attributable to depreciable property imbued with an inherent capital gain; Canadian resource property or foreign resource property; or inventory and eligible capital property imbued with an inherent capital gain. This rule strives to deny the bump of a partnership interest to the extent that the property of the partnership would not be eligible for the bump.
- Shares of a foreign affiliate, to the extent that the affiliate has a “tax-free surplus balance.” This rule strives to deny the bump of shares of a foreign affiliate to the extent that the bump otherwise would result in duplication of tax attributes (as discussed in [Structuring Oil and Gas Investments – Non-Resident Investors – Acquiring Assets Versus Acquiring Shares](#)).

The bump is quite important, and is most often used, where a corporation acquires control of another corporation and wishes to sell or transfer property of the acquired corporation (as discussed in [Structuring Oil and Gas Investments – Non-Resident Investors – Operating in Canada Through a Subsidiary](#)).

ACQUISITION OF CONTROL

The ITA contains rules that apply to a corporation where a **person**, or a group of persons, acquires **control** of the corporation. Acquisition of control includes *de jure* control in all circumstances and *de facto* control in some limited circumstances.

These acquisition-of-control rules are designed to restrict loss trading between arm’s length parties. The acquisition-of-control rules include:

- an automatic end to the taxation year of the acquired corporation immediately before the acquisition of control (the deemed year-end rule);
- a limitation on the utilization of **non-capital losses**;
- elimination of **capital losses**;
- a limitation on the deduction of UCC and **cumulative eligible capital (CEC)** balances;

- a limitation on the deduction of **ITCs**; and
- a limitation on deductions in respect of **CCEE**, **CCDE**, **CCOGPE**, and **ACFRE** accounts.

The deemed year-end rule was designed to make it more difficult for taxpayers to transfer losses. However, it is a rule of general application and has widespread implications.

The ITA imposes restrictions on the entitlement of a corporation to claim losses when a person or a group of persons acquires **control** of the corporation. The corporation cannot carry forward **net capital losses** after the acquisition of control. A corporation is permitted to file an election to crystallize accrued gains on capital property (including **depreciable property**). The election will result in an income inclusion; however, the corporation can apply against that income any net capital losses that would otherwise expire upon the acquisition of control and any non-capital losses.

A corporation may not carry back its net capital loss for a taxation year beginning after an acquisition of control to taxation years commencing before the acquisition of control. In addition, the corporation must treat as a capital loss realized in the year ending immediately before the acquisition of control the amount by which

the adjusted cost base of any capital property exceeds the fair market value of the property.

After an acquisition of control of a corporation, the corporation can deduct pre-acquisition-of-control non-capital losses only if the business that gave rise to those losses is carried on with a view to profit, and only against income arising from carrying on the same or a similar business. Non-capital losses arising after an acquisition of control can be carried back only against income from the same or a similar business.

Any amount by which the UCC or CEC balance exceeds the fair market value of the related depreciable property or **eligible capital property** is treated as a non-capital loss. The UCC or CEC balances are reduced accordingly. The deemed losses are subject to the acquisition-of-control rules.

The ITCs of a taxpayer on an acquisition of control are subject to rules similar to those applicable to non-capital losses.

On an acquisition of control of a corporation, deductions from the CCEE, CCDE, CCOGPE, and ACFRE accounts of the corporation are subject to the successor corporation rules.

ITCs and the successor corporation rules are discussed in [Deductions, Allowances, and Credits](#).

PARTNERSHIPS AND JOINT VENTURES

In the oil and gas industry, a **partnership** or **joint venture** may provide a more flexible investment structure, as compared with a corporation, where **arm's length** parties wish to undertake joint exploration, development, or production activities.

Unlike corporations, which are purely creations of statute, partnerships are to a large extent created and governed by contract; however, various provinces have enacted legislation applicable to partnerships. Joint ventures are completely created and governed by contract.

The distinction between a joint venture and partnership is not always clear-cut. In simple terms, a joint venture can be described as a contractual arrangement under which two or more parties hold a property in common. Typically, each party contributes the use of its own assets to the venture and shares in the expenses and revenues of the venture, as agreed by contract.

A partnership is often governed by a contract, whereby the parties specifically agree that their intention is to carry on business together as a partnership; and, as in a joint venture, they each contribute their own assets in exchange for a share in the expenses and the revenues of the business. However, partnerships do not require a contract and may be considered to exist even where the parties did not intend such an arrangement. A partnership may be deemed to exist if the parties carry on business in common with a view to profit.

Apart from the tax consequences, described below, the following consequences flow from a partnership arrangement:

- Subject to statutory rules governing **limited partnerships**, partners are jointly and severally liable for the actions of any partner in respect of the partnership activities.
- Property used in the business of the partnership will be considered property of the partnership and not the property of any particular partner.
- Subject to statutory rules governing limited partnerships, one partner may bind all other partners in the normal course of the business of the partnership, whether or not the partner has authority under the partnership agreement to bind the partnership, unless the **person** with whom the partner is dealing knows that the partner in question has no authority to act on behalf of the partnership.

To overcome the disadvantage of unlimited liability, participants in an oil and gas project may establish a limited partnership, in which a general partner manages the interests of the participants (the limited partners). However, investors may prefer the flexibility afforded by a joint venture arrangement. In order to ensure that the arrangement is not considered to be a partnership, the parties should:

- explicitly state in the joint venture agreement that their intention is not to create a partnership;
- share gross revenues and not net revenues; and
- fund each expense directly and not out of undrawn revenues.

The tax treatment of joint ventures and partnerships, discussed below, may govern the investment decision.

Income tax consequences

The ITA does not recognize joint venture arrangements. A joint venture therefore is not a separate taxable entity; instead, each party to the joint venture is directly taxable in its own right, with no intermediary computation of income or loss at the joint venture level.

In contrast, the ITA recognizes the existence of partnerships and provides for extensive rules relating to the computation of income and deductions by a partnership.

Except for some specific provisions (such as the rules applying to **flow-through shares** and to **SIFT entities**) discussed below, a partnership is not a separate taxable entity under the ITA. However, a partnership computes its income as if it were a separate person resident in Canada, and each partner, in computing its income in a taxation year, is required to include its share of the income or loss of the partnership for each fiscal period of the partnership ending in that taxation year. As a result, where a corporation is a member of a partnership and the fiscal period of the partnership ends after the taxation year-end of the corporation, the corporation may be able to defer its share of partnership income until the following taxation year. However, the ITA contains detailed rules that limit this deferral.

If the corporate partner (together with related or affiliated persons or partnerships) owns more than 10 percent of the interests in the partnership, the corporation is required to accrue partnership income for the portion of the partnership's fiscal period that falls within the corporation's taxation year (a **stub period**). In particular, the corporation must include in income an amount called "**adjusted stub period accrual**" (ASPA) in respect of the partnership for the stub period. ASPA is computed by a formula that prorates forward over the stub period the corporation's share of a partnership's net income from a business or property and net taxable capital gains for the partnership's fiscal periods that fall within the corporation's taxation year. The corporation

may reduce ASPA by making either or both of the following discretionary designations:

- If the partnership incurs qualified resource expenses (QRE), which consist of CEE, CDE, FRE and COGPE incurred by the partnership in the stub period, the corporation may be entitled to designate some or all of such QRE for the year to reduce its ASPA.
- The corporation may designate a discretionary amount to reduce ASPA to reflect the corporation's expectation or knowledge of the partnership's actual income for the stub period. The corporation may be required to include an interest charge in its income in the following year if the designation results in a deferral of partnership income by the corporation.

These rules were introduced in 2011. As a result of the addition of the new rules, a corporation might have been required to include in income an amount that represented more than one year of partnership income. A transitional reserve apportions the incremental income realized by the corporation on the transition over a five-year period.

The computation of the income or loss of the partnership excludes any proceeds from the disposition of a **Canadian resource property** or **foreign resource property** and any deductions in respect of CEE, CDE, COGPE, or FRE. Instead,

proceeds of disposition are allocated to the partners according to their respective interests in the partnership; and CEE, CDE, COGPE, or FRE incurred by a partnership in the partnership's fiscal year are included in computing the CCEE, CCDE, CCOGPE, and ACFRE accounts of the individual partners, who can then claim deductions for those expenses.

In contrast, other deductions or expenses, such as **CCA** claimed by a partnership and operating expenses of the partnership, are deductible by the partnership in computing its income or loss.

Provided that a partnership claims the maximum deductions available to it, the income tax consequences to a partner will be the same whether or not the partner claimed a share of the deductions directly.

SIFT legislation

In the first decade of this century, a number of publicly traded corporations converted to trusts or partnerships. The conversion enabled the entities to avoid corporate-level income tax and **capital tax**.

The government became concerned about the erosion of the corporate tax base and perceived distortions to the economy that arose because the entities chose to distribute most of their income rather than reinvest in their businesses. Accordingly, the government

introduced the **SIFT legislation** to tax publicly traded trusts and partnerships in a manner similar to corporations. In particular, the SIFT legislation imposes an entity-level tax on the non-portfolio earnings of SIFT partnerships and SIFT trusts that is similar to a corporate tax, and treats distributions of non-portfolio earnings by SIFT partnerships and SIFT trusts as dividends.

The ITA imposes tax on the business income of public partnerships; these are partnerships whose units have a market. The ITA equates these partnerships to corporations in respect of their non-portfolio earnings. Partners pay tax on their share of the after-tax business income as if it were a dividend.

Advantages of partnerships

A partnership can be used by a small number of persons wishing to carry out exploration and development where the desired tax and commercial results cannot be secured by the use of a corporate structure. Where applicable, a non-resident member of a partnership will be deemed to be carrying on business in Canada and will be required to file an annual federal income tax return.

A partnership provides a number of advantages over the use of other forms of organization.

Reorganization of partnerships

The ITA contains a set of beneficial reorganization provisions for **Canadian partnerships**. These provisions permit:

- a person to transfer property to the partnership on a tax-deferred basis in exchange for a partnership interest,
- the winding-up of the partnership on a tax-deferred basis, and
- the merger of two or more Canadian partnerships.

A partnership form of organization permits one person to transfer an indirect interest in oil and gas assets to another in exchange for the funding by the other of the exploration for or development of the assets (in some circumstances, this result may be accomplished through the use of a **farm-in** arrangement, described below). In contrast, the direct transfer of an interest in the oil and gas assets from one person to another would be a taxable event.

Dispositions

Partnership interests may be held on capital account so that a future disposition could result in a **capital gain**. In contrast, since parties to a joint venture hold assets directly, a disposition of a joint venture interest is regarded as a disposition of the underlying assets in respect of that joint venture, potentially resulting in income in the case of **resource property** (if the proceeds cause the CCDE account to be negative

at the end of the year) or recapture in the case of **depreciable property**, as well as a capital gain on capital property.

As an alternative to a corporation

Frequently, two or more persons (usually corporations) wish to cooperate in carrying out an exploration or development program. If the persons entering into the project are in different circumstances and wish to participate differently in the project, the creation of a new corporation may not be appropriate for the project.

Subject to anti-avoidance rules, a partnership may be used to allocate disproportionately the amount of eligible deductions incurred through the project, as illustrated in Example 3.

A partnership may also be used as an alternative to a sole purpose corporation for the development of a project. A sole purpose corporation may not be appropriate because the deductions generated by the project may be used only against the income generated from the project. It may well be that the partners could use the deductions generated by the project directly against their own income long before the sole purpose corporation would be entitled to do so. Consequently, in such circumstances, a partnership could be used and the various expenses could be allocated to the partners that could use the deductions sooner.

EXAMPLE 3

Allocation of partnership expenses

- Corporation A contributes a Canadian resource property to the arrangement.
- Corporation B contributes the funds necessary for exploration.
- Corporations A, B, and C agree to fund the development of any discovered reserves.

From a business perspective, it is appropriate to allocate the expenses arising from the contribution of the property to Corporation A; to allocate to Corporation B all the exploration expenses; and to allocate the cost of development, including CCA, to each of Corporations A, B, and C in their respective portions. This result can be accomplished through the use of partnership allocations but not through the use of a corporation (however, flow-through shares may be used in some circumstances to accomplish some of the objectives).

FARM-INS/FARM-OUTS

A **farm-out** arrangement is one in which one party (a **farmor**) has an interest in a **resource property** and agrees to grant an interest in that resource property to another party (a **farmee**), in exchange for the farmee's either funding or performing exploration and development work on the farmor's property. The farmee's undertaking is typically referred to as a **farm-in** and the farmor's commitment is referred to as a farm-out. There is no standard form of farm-out agreement. Instead, the terms of each farm-out agreement are unique to the particular circumstances.

The taxation of farm-out arrangements is, in practice, heavily dependent on certain administrative concessions by the **CRA**. In the absence of these concessions, a farm-out arrangement involving a transfer to the farmee of beneficial ownership of all or part of a farmor's **working interest** in a resource property might result in a taxable disposition by the farmor.

Since there is little case law that has considered the taxation of farm-out arrangements, taxpayers will typically try to fall within the CRA's administrative policies concerning these arrangements. In particular, it is the CRA's assessing practice that a farm-out results in the farmor having a disposition but not receiving any proceeds of disposition. Instead, the farmee is considered to incur **resource expenses**

in order to earn an interest in the property. After the farmee has completed its spending commitment, the farmor and farmee will have an agreed ownership interest in the **working interest**. The CRA, however, limits this administrative position to only unproven resource properties, which the CRA considers to be resource properties to which proven reserves have not been attributed. CRA has not developed a position in the oil and gas industry permitting the farmor to give up and the farmee to acquire **depreciable property** on a tax-exempt basis.

In the oil and gas industry, the most common form of farm-out arrangement is one in which the farmor has an interest in oil and gas claims and the farmee is an oil and gas corporation. Usually, the farmee agrees to incur a fixed dollar amount of exploration work over a specified period of time. Provided that the farmee incurs the expenses in accordance with the agreement, the farmee will typically be entitled to receive a transfer of the oil and gas claims and the farmor will be entitled to a **gross overriding royalty (GORR)** in the property.

A second arrangement in the oil and gas industry is one in which the farmee agrees to incur a fixed dollar amount of exploration work on the farmor's oil and gas claims over a specified period of time in order to earn an interest in the property (i.e., working interest). Thereafter, the parties share the requisite expenses to explore and develop the property in proportion to their interests.

FOREIGN OPERATIONS

For a Canadian resident carrying on oil and gas operations in a foreign jurisdiction, an important decision is whether it is better, from a tax perspective, to carry on the activity through a branch or through a foreign entity. While most foreign jurisdictions will allow the investor to choose the vehicle through which it prefers to carry on business, some will require a non-resident to establish a subsidiary in the particular jurisdiction to undertake the oil and gas activities. From a Canadian tax perspective, the difference between operating through a branch and operating through a foreign entity can be significant.

Where a **Canadian corporation** carries on business through a foreign entity, the Canadian tax consequences will depend greatly on whether the foreign entity is treated as a corporation for Canadian tax purposes. In making this determination, the legal characteristics of the foreign entity under the laws of the foreign jurisdiction must be compared with the legal characteristics of entities in Canada. The entity should be classified in the same manner as the Canadian entity with which it shares the most similarities. It is sometimes very difficult to determine the appropriate classification of the foreign entity.

Operation through a branch

Canadian corporations operating in foreign jurisdictions through a **branch** are subject to Canadian tax on the income earned by that branch, whether or not any funds are remitted to Canada. Operating through a branch may be advantageous during the initial exploration and start-up phases of an oil and gas project, since losses incurred by the branch may shelter other income earned by the Canadian corporation from Canadian tax. However, a subsequent transfer of the assets of the foreign branch to a foreign subsidiary would be a taxable transaction for Canadian tax purposes. Any proceeds of disposition of a **foreign resource property** would be included in income of the Canadian corporation, net of reasonable expenses. An election is also available to treat the proceeds as a reduction of the ACFRE account of the taxpayer and may result in income subject to tax. Under the ITA, proceeds of disposition of a foreign resource property are on income account and not on capital account (as discussed in [Deductions, Allowances, and Credits – Foreign Resource Expenses](#)).

There is, therefore, a trade-off between tax payable in the future and the upfront deduction of losses. There is also a risk that the assets of the branch may not be transferable to a corporation on a tax-deferred basis under foreign law or under the provisions of a relevant

tax treaty. Therefore, theoretically, assets should be transferred at an early stage before a significant appreciation in value occurs. This is easier said than done. In the oil and gas context, one successful well may turn a property with nominal value into one of significant value.

A transfer of property may also result in other taxes, such as sales and transfer taxes or stamp duties. Consequently, the potential liability for such taxes must be taken into account in considering which vehicle to use at the time of commencement of operations. In addition, a subsequent transfer of assets may require government approvals, as well as consents from third-party participants in the oil and gas operations.

Where the income earned by the branch is subject to tax in the foreign jurisdiction, a foreign tax credit may reduce the Canadian federal income tax liability and prevent double taxation. A foreign tax credit may be claimed for the income taxes paid or payable to a foreign jurisdiction in respect of the business profits of the branch to the extent that the foreign taxes do not exceed the Canadian income taxes otherwise payable on those profits. To the extent that the foreign income taxes paid to a jurisdiction exceed the Canadian income taxes otherwise payable on branch profits, the unused credit may be carried back for three years and forward for 10 years in the case of business-income taxes.

These carryforward and carryback provisions do not apply to taxes that are not in respect of income earned by the taxpayer from a business carried on in the country (e.g., non-business-income taxes, such as foreign withholding taxes on dividends, interest, and royalties). Further, the foreign tax credit is available only in respect of taxes assessed, based on a measure of income or profits. Therefore, royalties, stamp duties, and **capital taxes**, as well as sales, value-added, certain alternative minimum taxes or turnover taxes are not eligible for the foreign tax credit, unless the relevant tax treaty specifically identifies the tax as one for which Canada must grant a credit.

Provincial foreign tax credits are available only for non-business-income taxes paid or payable, since foreign business profits should not be subject to tax in any Canadian province.

Operation through a foreign corporation

Where foreign operations are expected to be profitable, there may be significant advantages to the use of a foreign subsidiary corporation over a branch. As described in more detail below, the **active business income** earned by a **foreign affiliate** should not be taxable in Canada until a dividend is paid to a Canadian-resident corporation or individual. Further, dividend income received by a Canadian corporation

from a foreign affiliate that is resident in and carries on an active business in a jurisdiction with which Canada has concluded an income tax treaty or a **tax information exchange agreement (TIEA)** should be exempt from Canadian income tax (as discussed in [Structuring Oil and Gas Investments – Foreign Affiliates](#)). Income of a foreign entity that is not a controlled foreign affiliate is subject to Canadian tax only when the income is distributed to Canada by way of dividend.

This exemption of Canadian tax is available only where the foreign corporation is a resident of the foreign jurisdiction under Canadian domestic law as well as an applicable income tax treaty. Under Canadian common law principles, a foreign corporation may be considered to be a resident of Canada if the central management and **control** of the foreign corporation is exercised in Canada. If its central management and control are exercised in another country, it may be considered a resident of that other country, not of Canada. To substantiate that the foreign entity is not resident in Canada, it is critical that the directors (or equivalent) of the foreign affiliate meet regularly in that foreign jurisdiction, that they have the authority to manage and oversee the affairs of the corporation, and that they exercise that authority independently. The directors can consider the wishes of the Canadian shareholders in arriving at their decisions, but they must still exercise independence in deciding whether or not to implement those wishes.

Distributions from a foreign corporation to a Canadian shareholder may be subject to foreign withholding tax, and a gain realized on a sale of the shares of the foreign corporation (including, in some jurisdictions, an indirect sale) may also be subject to foreign income tax under local domestic law, as well as to Canadian income tax. Intermediary holding corporations in treaty jurisdictions may be used to reduce the rate of foreign withholding tax on distributions to Canada, and to eliminate Canadian and foreign income tax on capital gains that may otherwise be payable on the disposition of the shares of the foreign corporation. Although the tax benefits of these structures may be substantial (see the discussion in [Structuring Oil and Gas Investments – Foreign Affiliates](#)), they may be subject to challenge by tax authorities under a “substance-over-form” doctrine or general beneficial ownership principles. Furthermore, certain foreign jurisdictions have enacted specific anti-avoidance rules that could deny the benefits of a treaty to the intermediary holding corporation, by looking through the structure to the Canadian parent. Other countries have enacted rules of general application that deem capital gains derived from the sale of an offshore company to be subject to local tax if more than a specified percentage of the fair market value, assets, or income of the foreign holding corporation is directly or indirectly derived from domestic operations or assets.

Foreign affiliates

As discussed above (see [Structuring Oil and Gas Investments – Foreign Operations](#)), a Canadian-resident investor undertaking oil and gas activities outside Canada must weigh the domestic and foreign tax consequences associated with the different business structures through which oil and gas operations can be carried on. Where the oil and gas venture is generating a profit, it can be advantageous to operate through a **foreign affiliate**. However, Canada’s foreign affiliate rules are complex, and careful planning is necessary to achieve the desired tax result. The summary that follows provides a simplified overview of the tax treatment of foreign affiliates under the ITA.

The foreign affiliate regime

The ITA provides a combined exemption/credit system for income earned by a Canadian-resident taxpayer through a foreign affiliate. A foreign affiliate of a Canadian resident is defined as a non-resident corporation in respect of which the Canadian resident owns:

- not less than 1 percent, and
- either alone or together with related **persons**, 10 percent or more

of the shares of any class of the corporation. A foreign affiliate is a **controlled foreign affiliate** if the Canadian resident:

- has control of the foreign affiliate, or
- would have control over the foreign affiliate if it held, together with its own shares, all of the shares of up to four arm's length Canadian resident shareholders and all of the shares owned by related persons to the Canadian taxpayer and the four arms-length Canadian resident shareholders.

Generally, when referring to **control** in the definition of a **controlled foreign affiliate**, it means de jure control. De jure control has been interpreted to mean the right of control that rests in ownership of such a number of shares which carries the right to a majority of the votes in the election of the board of directors.

An exemption/credit applies to income received by the Canadian resident corporation in the form of dividends paid by the foreign affiliate. A reduction of tax may also be available in respect of gains on a sale of shares of the foreign affiliate.

The Canadian tax rules relating to foreign affiliates can be grouped into two categories: the **surplus rules** and the **foreign accrual property income (FAPI)** rules.

The surplus rules

The surplus rules are relevant in determining:

- the tax payable by a **Canadian corporation** on dividends received from both controlled and non-controlled foreign affiliates, and
- the gain that is subject to tax on a sale by a Canadian-resident corporation of shares of a foreign affiliate.

A Canadian-resident taxpayer that sells shares of a foreign affiliate is subject to tax on the **taxable capital gain**. Similarly, a Canadian-resident taxpayer is also subject to tax on the taxable capital gain realized on the sale by one foreign affiliate of shares of another foreign affiliate unless the shares of the foreign affiliate that are sold are **excluded property** (see [The FAPI rules](#)). Shares of a foreign affiliate are excluded property if they derive **all or substantially all** of their fair market value from property that is principally used for the purpose of gaining or producing income from an active business. A Canadian corporation may elect to reduce the proceeds of disposition (which are relevant to computing the **capital gain** or **capital loss**) to the extent of the underlying surplus. Where an election is made, these rules deem a dividend to have been paid for the amount elected, and consequently reduce the gain.

Regardless of its legal form, a pro rata distribution by a foreign affiliate is deemed to be a dividend except where the distribution is made:

- in the course of a liquidation and dissolution of the affiliate;
- on a redemption, acquisition, or cancellation of a share of the affiliate; or
- as a “qualifying return of capital” in respect of the share.

On a distribution of paid-up capital of a foreign affiliate, which otherwise would be treated as a dividend, a taxpayer may elect to treat the distribution as a qualifying return of capital. Under this election:

- the distribution is received tax-free to the extent of the **adjusted cost base** of the taxpayer's shares of the foreign affiliate, and
- the adjusted cost base to the taxpayer of its foreign affiliate shares is reduced by the amount of the distribution.

The tax payable by a corporation resident in Canada in respect of a dividend received from a foreign affiliate depends on the surplus account of the foreign affiliate

out of which the dividend is paid. There are four surplus accounts:

- **exempt surplus,**
- **hybrid surplus,**
- **taxable surplus, and**
- **pre-acquisition surplus.**

Dividends paid by a foreign affiliate to a Canadian resident are deemed to be paid out of the surplus accounts in the following order:

- 1 exempt surplus,
- 2 hybrid surplus,
- 3 taxable surplus, and then
- 4 pre-acquisition surplus.

A taxpayer may be able to vary the application of the dividend ordering rules by making an appropriate election. Pursuant to such an election, dividends may, in certain circumstances, be paid out of taxable surplus before hybrid surplus, and pre-acquisition surplus before exempt, hybrid surplus, or taxable surplus.

Dividends can be paid out of a particular surplus account only if the balance in that account exceeds the total of any deficit balances in the other surplus accounts. For example, dividends may be paid out of exempt surplus only to the extent that the amount

of exempt surplus exceeds the total of any hybrid deficit and taxable deficit. A similar rule applies for dividends paid out of hybrid and taxable surplus. Pre-acquisition surplus is a residual concept where any dividend paid in excess of the net positive balance in the other surplus accounts is deemed to be paid from pre-acquisition surplus.

Exempt surplus of a foreign affiliate includes the **active business income** of the foreign affiliate that is earned in a treaty country or in a country with which Canada has a TIEA, provided that the foreign affiliate is also resident in a treaty country or a TIEA country under both Canadian domestic law and for purposes of the applicable tax treaty or TIEA. Exempt surplus also includes any capital gain from the disposition of property used in a qualifying active business, and the non-taxable portion of other capital gains (with the exception of gains included in hybrid surplus, discussed below). Dividends that are received by a Canadian-resident corporation out of a foreign affiliate's exempt surplus are exempt from tax in Canada.

Hybrid surplus includes the amount of a capital gain realized by a foreign affiliate on a disposition of excluded property that is a share of another foreign affiliate, a partnership interest, or a currency hedging contract that relates to certain excluded property. One-half of the amount of dividends received out of

hybrid surplus is exempt, and the other half is taxable, subject to a deduction for a grossed-up amount of the foreign tax paid on the capital gain that generated the dividend and for any foreign withholding tax paid on the dividend itself.

Taxable surplus includes all other income earned by the foreign affiliate, including FAPI, as well as **non-qualifying active business income**. Taxable surplus also includes taxable capital gains that are not included in exempt surplus or hybrid surplus. Dividends received by a Canadian-resident corporation out of a foreign affiliate's taxable surplus are taxable in Canada, subject to a deduction for a grossed-up amount of the foreign tax paid on the income that generated the dividend and for any foreign withholding tax paid on the dividend itself.

Pre-acquisition surplus is a residual concept in that only dividends in excess of exempt, hybrid, and taxable surplus are deemed to arise from pre-acquisition surplus. Dividends from pre-acquisition surplus are exempt from tax in Canada, but unlike other surplus dividends, they reduce the tax cost of the shares of the foreign affiliate payer. If the cumulative pre-acquisition surplus dividends and returns of capital exceed such tax cost, a deemed capital gain arises.

The upstream loan rules

It was previously common practice for foreign affiliates engaged in oil and gas operations to repatriate amounts by way of loans to their Canadian parent or, if the Canadian parent was a subsidiary of a non-resident corporation, to the non-resident corporation. As a result, they avoided the Canadian tax that would have arisen on a dividend paid out of taxable surplus.

The “upstream loan rules” seek to ensure that no Canadian tax benefit is obtained through the use of an upstream loan rather than a dividend. Where a foreign affiliate of a taxpayer makes a loan to a **specified debtor**, such as the Canadian-resident shareholder of the foreign affiliate or a person that does not deal at arm’s length with such shareholder, the taxpayer must include in income the **specified amount** of the loan. Where the specified debtor is the Canadian taxpayer, the specified amount is the product of the principal amount of the loan and the Canadian-resident shareholder’s direct or indirect equity interest in the lending foreign affiliate. If the specified debtor is another foreign affiliate of the Canadian taxpayer, the specified amount is the product of the principal amount of the loan and the difference between the Canadian-resident shareholder’s direct or indirect equity interest in the lending and borrowing affiliates. If the loan is repaid (other than as part of a series of loans or other transactions and repayments) within two years, the taxpayer is not required to include the

specified amount in income. Where the taxpayer does have an income inclusion, the taxpayer is entitled to a final deduction in the year in which the loan is ultimately repaid in proportion to the amount that was previously included in income.

Where a taxpayer has an income inclusion pursuant to the upstream loan rules, it may deduct a portion of such income inclusion under a special reserve-like mechanism. More specifically, the taxpayer may deduct a portion of the income inclusion if the taxpayer demonstrates that the portion would, were it paid to the taxpayer directly or indirectly by the foreign affiliate as dividends out of exempt, hybrid, taxable, or pre-acquisition surplus, reasonably be considered to have been deductible in computing taxable income. The taxpayer is required to add back into income its deduction for the immediately preceding taxation year, and may then claim a fresh deduction for the current year if the conditions for application continue to be met. The reserve mechanism does not reduce the surplus accounts of the foreign affiliate, but if those surplus accounts diminish for a taxation year while the loan remains outstanding, the taxpayer may realize an income inclusion.

The FAPI rules

The purpose of the **FAPI** rules is to prevent the deferral of Canadian tax on passive property income, or income deemed not to be active business income, earned offshore.

FAPI includes property income (e.g., interest, dividends, rents, and royalties), as well as income from an investment business and certain taxable capital gains. A Canadian resident is taxable on a current basis in respect of FAPI earned by a controlled foreign affiliate (but not a non-controlled foreign affiliate), whether or not the income is repatriated (distributed to the Canadian resident), subject to a tax credit for foreign taxes paid on the income.

An investment business includes a business carried on by a foreign affiliate whose principal sources of income include:

- income from property,
- income from the insurance or reinsurance of risk,
- income from the factoring of receivables, or
- profits from the disposition of investment property (including commodities and Canadian and **foreign resource properties**).

A business (other than a business conducted principally with non-arm’s length parties) that derives income or profit principally from these sources may not be an investment business if it employs, alone or together with certain other related parties, more than five full-time employees in the business throughout the year. This exception does not apply to all types of “passive” businesses listed above (only certain listed types of activities qualify), although it generally applies to foreign resource royalties on foreign resource properties.

In some cases, income that would otherwise be FAPI is re-characterized as active business income for tax purposes, with the result that the FAPI rules do not apply. This occurs typically where the income is connected to an active business carried on by another foreign affiliate of the Canadian resident. For example, the interest income of a foreign affiliate derived from an intercompany financing arrangement with another foreign affiliate is not FAPI to the extent that the interest payments are deductible in computing the other foreign affiliate's active business earnings. The same treatment will apply to royalty income where, for example, one foreign affiliate earns resource royalties paid by another foreign affiliate with active oil and gas operations.

Canada has rules to prevent taxpayers from eroding the Canadian tax base by diverting income from Canadian-source activities to foreign affiliates. This income may relate to income from the sale of property, services, interest and leasing, and insurance and reinsurance. In such cases, the income is considered FAPI.

The entitlement of a Canadian resident to deduct a tax credit for foreign taxes paid on FAPI is subject to the "foreign tax credit generator" rules. These rules can deny a foreign tax credit where foreign taxes are incurred as a part of a transaction that involves a "hybrid instrument" that is characterized as equity

for Canadian tax purposes but as debt under foreign tax law. These rules are intended to deny recognition of foreign tax credits where the foreign tax burden is not ultimately borne by the taxpayer. However, the rules are broadly drafted and can apply in unexpected circumstances. Specifically, there is no requirement for a direct link between the hybrid instrument and the transaction generating the FAPI; the rules will apply whenever there is a hybrid instrument in the same chain of ownership as the affiliate earning the FAPI. Thus, if a hybrid instrument or entity is present in a foreign affiliate group, the implications for all affiliates in the same ownership chain needs to be considered.

The foreign affiliate dumping rules

The foreign affiliate dumping rules deter certain arrangements that allowed non-residents of Canada with Canadian subsidiaries to undertake transactions that reduced their liability for Canadian tax without, in the government's view, providing an economic benefit to Canada.

The foreign affiliate dumping rules apply to an "investment" in a foreign affiliate by a "corporation resident in Canada" (CRIC) that is controlled by a non-resident corporation. An "investment" in a foreign affiliate includes:

- an acquisition of shares of the foreign affiliate;
- a contribution of capital to the foreign affiliate;

- an acquisition of shares of another corporation resident in Canada whose shares derive more than 75 percent of their value from foreign affiliate shares;
- a loan to or an acquisition of a debt of a foreign affiliate;
- the extension of the maturity date of a debt obligation owing by a foreign affiliate to a CRIC; and
- the extension of the redemption, acquisition, or cancellation date of shares of a foreign affiliate held by a CRIC.

Certain trade debts and debts acquired from an arm's length person in the ordinary course of business are excluded. In certain cases, an election is available to treat a debt obligation as a "pertinent loan or indebtedness" (PLOI). The foreign affiliate dumping rules do not apply to the PLOI, but the CRIC must include in income interest on the PLOI at a prescribed rate (less any interest actually charged pursuant to the terms of the debt obligation).

Where the rules apply, the following consequences may result:

- If the CRIC paid non-share consideration for the investment, the CRIC is deemed to have paid to its foreign parent a dividend in an amount equal to the fair market value of such consideration. Canadian

withholding tax applies to the deemed dividend. In certain circumstances, under an offset mechanism, the paid-up capital in the shares of the CRIC can be reduced to decrease or eliminate the deemed dividend.

- If the CRIC issued shares in consideration for the investment, the paid-up capital in such shares is reduced by the amount of the investment in the foreign affiliate. The elimination of paid-up capital restricts thin capitalization room to limit the ability of the CRIC to deduct interest expense on cross-border debt and restricts the amount that can be repatriated as a return of capital free of Canadian withholding tax.

There are two main exceptions that will preclude the application of the rules where a CRIC makes an investment in a foreign affiliate. The first exception is intended to exempt investments that are strategic expansions of a Canadian business abroad; however, this exception is unlikely to be useful since its scope is very narrow. The second exception applies where the investment is part of an internal reorganization that is not considered to result in a new investment in a foreign affiliate.

Where the paid-up capital in the shares of the CRIC is reduced under the rules, such paid-up capital can be reinstated, provided certain conditions are met, immediately before:

- a return of capital by the CRIC to its foreign parent, or

- an in-kind distribution of:
 - the shares of the foreign affiliate that constituted the original investment,
 - shares of another foreign affiliate substituted therefor, or
 - the proceeds of disposition of such shares or certain other distributions from another foreign affiliate.

The paid-up capital reinstatement before the return of capital avoids a deemed dividend arising on the transaction to the extent that the amount distributed on the return of capital exceeds the paid-up capital in the shares of the CRIC.

International holding corporations

Holding corporations incorporated in foreign jurisdictions are often considered by oil and gas corporations to hold other foreign oil and gas corporations. Both the commercial and tax aspects of a foreign holding corporation need to be considered.

Dividends paid to a holding corporation will not be subject to Canadian tax and may be subject to little or no tax in the jurisdiction of the holding corporation. The use of a holding corporation therefore defers tax on the earnings until they are ultimately repatriated to Canada. Distributions to Canada may qualify for an exemption or credit where they are paid out of exempt, hybrid, or taxable surplus (refer to [The surplus rules](#)).

A holding corporation may also be used to defer the payment of Canadian tax on capital gains realized from a sale of shares of a foreign affiliate where the shares constitute **excluded property**.

However, the use of holding corporations presents a number of issues. Many jurisdictions are becoming more aggressive in challenging international holding corporations based on either specific legislations or more general rules such as substance over form, beneficial ownership and treaty abuse. This is particularly the case where the holding corporation does not carry on active business operations of its own.

A number of jurisdictions have also introduced legislation to tax sales of the shares of foreign corporations that derive a significant portion of their value from domestic assets, operations, or shares of a domestic company (so-called “indirect sales”). Typically, the source country will impose liability for any tax unpaid by the vendor (and related interest and penalties) on the purchaser or the domestic (target) entity.

International financing corporations

Most inter-affiliate payments (including interest, rents, royalties, and insurance premiums) are exempt from FAPI treatment (and thus not taxable in Canada) if the payer is a foreign affiliate in which the Canadian taxpayer has an interest consisting

of at least 10 percent of the votes and value of the foreign affiliate and the expense is deductible from the active business income of the payer. It is therefore common for a Canadian multinational to establish an affiliate in a low-tax jurisdiction to finance its foreign operations (as discussed in OECD BEPS project and the impact on transfer pricing rules). Similar benefits can be achieved using international leasing, licensing, or captive insurance affiliates. If the financing affiliate is resident in a treaty or **TIEA** country and the payer is both resident in and carries on business in (another) treaty country, the income earned by the financing entity is exempt surplus and can be repatriated to Canada free of tax. This allows for a permanent tax saving to the Canadian parent.

Transfer pricing

Transfer pricing refers to the process of setting prices for cross-border transactions within a multinational group. Most countries, including Canada, have rules in place to prevent the erosion of the country's tax base through inappropriate transfer pricing.

Common cross-border intra-group transactions in the oil and gas industry which would be subject to transfer pricing rules include:

- The sale of product, including procurement of inputs, and marketing of finished and semi-finished products
- The provision of head office services such as management and support services

- The provision of strategic and technical services
- Intercompany loans and other financing, and provision of guarantees of third party financing

Canadian transfer pricing rules and guidance

The foundation of Canada's transfer pricing rules is the 'arm's length principle' found in the Related Persons article of most tax treaties. The arm's length principle requires associated enterprises to transact with each other at terms and conditions that would otherwise have prevailed in the open market.

Where a Canadian taxpayer transacts with an associated enterprise on terms and conditions that are less favorable than would have been agreed with an arm's length party, the transfer pricing rules allow the CRA to adjust the amounts of the transaction in computing the taxpayer's taxable income. In exceptional circumstances, the transaction can be disregarded, where such a transaction would, in the CRA's opinion, not have occurred between arm's length parties.

In interpreting the operation of the transfer pricing rules, the CRA has issued substantial guidance in the form of information circulars and transfer pricing memoranda. This guidance closely follows the guidance in the internationally recognized OECD Transfer Pricing Guidelines for Multinational Enterprises and Tax Administrations (OECD Guidelines).

Transfer pricing penalties and contemporaneous documentation requirements

Where a transfer pricing adjustment is made, a penalty may apply if the CRA determines that the taxpayer did not make reasonable efforts (as defined in Transfer Pricing Memorandum 9) to determine and use arm's length transfer prices. If applied, the penalty is computed as 10 percent of any transfer pricing adjustments, irrespective of whether any income tax has been underpaid. The penalty will only apply where the adjustment to income exceeds the lesser of 10 percent of gross revenue or \$5 million.

For purposes of calculating transfer pricing penalties, taxpayers are deemed not to have made reasonable efforts unless they have prepared contemporaneous documentation, as prescribed in the ITA, to document the analysis undertaken to determine and use arm's length transfer prices.

In addition to penalties, transfer pricing adjustments may also give rise to deemed dividends, subject to withholding tax.

OECD BEPS project and the impact on transfer pricing rules

Transfer pricing, as well as a number of other International tax areas, are currently undergoing substantive global review, as part of the OECD's **Base Erosion and Profit Shifting (BEPS)** Action Plan. This

extremely ambitious endeavor, fully supported by the G-20 and with extensive consultation with developing countries, is expected to substantively modernize and change current Transfer Pricing and International Tax norms and standards, as well as documentation and reporting obligations.

Canada release draft legislation in June 2016 introducing country-by-country reporting requirements for multinationals with consolidated revenues in excess of €750 million. The draft legislation is consistent with the OECD's recommendation. The first period to report will be taxation years started on or after January 1, 2016.

Canada has been an active participant in the BEPS project and is expected enact or follow the majority of the OECD's transfer pricing recommendations, which also include:

- Expanded transfer pricing documentation requirements following a global 'masterfile' and local country file format
- Adoption – likely retroactively to all open tax years – of revisions to the OECD guidelines including:
 - An increased emphasis in transfer pricing analyses on the performance of significant people functions, including strategic leadership, as a key value driver
 - A requirement to positively confirm that the taxpayer's actual conduct matches relevant written intercompany agreements

- A new chapter on determining transfer pricing for commodities
- A safe harbour for low value intragroup services.

NON-RESIDENT INVESTORS

Acquiring assets versus acquiring shares

A non-resident investor that intends to start up an oil and gas business in Canada, or to acquire an existing business, must consider:

- whether it will acquire the assets directly or acquire shares of a corporation holding the assets; and,
- whether it will carry on business in Canada directly or through a Canadian corporation.

An asset purchase may be advantageous to the purchaser from a Canadian income tax perspective because it will allow the purchaser to claim deductions, such as CCA and **resource deductions**, using the fair market value of the assets at the time of purchase rather than their historical cost to the vendor. An asset purchase may, however, result in the realization of ordinary income to the vendor, as opposed to a **capital gain**. In particular, the sale of intangible oil and gas rights may give rise to ordinary income. Asset sales are more complicated than share sales and frequently require government consents and third-party approvals.

If the investor decides to invest in Canada through an acquisition of shares, there may be an opportunity to increase (or bump) the tax cost of non-depreciable capital assets (land, other than **Canadian resource property**, and shares of a subsidiary) held by the acquired corporation to their fair market value subsequent to the acquisition (as discussed in [Structuring Oil and Gas Investments – Corporate Reorganizations](#)). The tax benefits of a bump are limited because it is not possible to increase the tax cost of property in respect of which a taxpayer may claim deductions in computing income.

However, the bump can be of great significance to a foreign purchaser of a **Canadian corporation** where the Canadian corporation owns subsidiaries that carry on business only in foreign jurisdictions. A foreign purchaser in such circumstances may want to:

- incorporate a Canadian corporation to purchase the Canadian target;
- wind up the Canadian target (or amalgamate the Canadian purchaser and the Canadian target) in order to bump the tax cost of the shares of the foreign subsidiaries; and
- transfer the foreign subsidiaries out from under the Canadian target.

The reason for this form of transaction is that it may be more efficient for the foreign purchaser to hold such foreign subsidiaries directly or in a dedicated offshore holding structure (for example, such a corporate organization avoids an additional layer of Canadian withholding tax on future repatriations). The bump may allow the purchaser to effect the transfer without incurring any significant Canadian tax. This feature of the Canadian tax system is particularly useful on a takeover where the target has no Canadian operations but is a holding corporation that has only subsidiaries with **oil and gas properties** situated in other jurisdictions; such a corporate organization is common for junior and intermediate oil and gas companies listed on the Canadian stock exchange. However, the bump is not available where the foreign purchaser issues its own shares as consideration for the acquisition if shares of the foreign purchaser derive more than 10 percent of their fair market value from bumped property (as discussed in [Structuring Oil and Gas Investments – Wind-Ups of Subsidiaries – Election to Bump Cost of Acquired Property](#)).

Where a Canadian corporation owns shares of foreign subsidiaries, two other considerations may affect the decision of a non-resident investor to acquire shares of the Canadian corporation:

- The foreign affiliate dumping rules may apply in certain cases. In particular, certain Canadian public

companies do not undertake significant direct oil and gas operations but act as holding companies for foreign subsidiaries that carry on those activities in foreign jurisdictions. The foreign affiliate dumping rules may apply where a foreign corporation acquires such a Canadian public company through the use of a Canadian acquisition corporation.

- Certain rules attempt to ensure that an unrelated party cannot obtain aggregate tax attributes of a foreign affiliate on an acquisition of control in excess of the fair market value of the foreign affiliate's shares. Two rules work together to achieve this objective:
 - On an **acquisition of control** of a Canadian corporation, the exempt surplus of the corporation's top-tier foreign affiliates is reduced immediately before the acquisition of control to the extent that the aggregate of each affiliate's tax-free surplus balance and the adjusted cost base of the affiliate's shares exceeds the fair market value of those shares. The top-tier foreign affiliate's tax-free surplus balance is the total of the top and lower-tier foreign affiliates' surplus balances to the extent that a dividend paid by the top-tier foreign affiliate would be fully deductible.
 - On a tax deferred wind-up of the Canadian corporation, or an amalgamation, the bump of

the shares of the foreign corporation may be restricted. More specifically, the bump room in respect of the foreign affiliate's shares is reduced by the foreign affiliate's tax-free surplus balance.

Operating in Canada through a branch

A foreign corporation may operate in Canada directly as an unincorporated business, or through a **joint venture** or **partnership** structure (as discussed in [Structuring Oil and Gas Investments – Partnerships and Joint Ventures](#)). In these circumstances, the foreign corporation will be subject to tax in Canada on income from its Canadian branch, similar to a Canadian corporation. The branch will be treated as a separate and independent entity for the purposes of determining its Canadian-source income subject to tax in Canada, and expenses incurred by the head office may be allocated to the branch under general transfer pricing principles. Since Canada does not have a loss consolidation regime (see [Overview of the Canadian Tax Regime – Income Taxation – Utilization of Losses](#)), losses incurred by the branch cannot be used to offset any income earned by other Canadian corporations held by the foreign investor in Canada. Foreign corporations carrying on business in Canada are required to file a corporate tax return annually with the CRA.

Foreign corporations carrying on business in Canada are also subject to a branch profits tax, which is a statutory 25 percent tax on after-tax income of the branch that is not reinvested in Canadian business assets. The tax rate is generally reduced under Canada's tax treaties to the rate of withholding tax imposed on dividends paid by a Canadian subsidiary to a parent in the jurisdiction of the parent (usually 5 percent). Some treaties also provide for an exemption for the first \$500,000 of earnings subject to the branch profits tax.

A key advantage to the branch structure is that the losses incurred by the branch may be used to shelter other sources of income from tax in the foreign jurisdiction. This structure may not be advantageous, however, where the foreign jurisdiction does not have an exemption system and the corporate tax rate is higher than the Canadian corporate tax rate. Further, the foreign corporation will have limited control over the payment of Canadian branch profits tax (which is determined by formula regardless of actual transfers of cash to the head office) as compared with the payment of dividends by a Canadian corporation. The branch tax formula may hamper the ability to adequately plan in jurisdictions with a foreign tax credit system.

A Canadian branch can be incorporated into a Canadian subsidiary on a tax-deferred basis for Canadian tax purposes. The new subsidiary inherits

the UCC and resource pools (although the latter are subject to restrictions (as discussed in [Deductions, Allowances, and Credits – Successor Corporation Rules](#)). However, any loss carryforwards of the branch cannot be transferred to the Canadian subsidiary or otherwise offset against income of any Canadian-resident entity or any other foreign entity with a Canadian branch. The tax consequences in the foreign corporation's country of residence of incorporating the assets must also be considered. Such consequences may include the recognition of gain and the recapture of branch losses previously deducted in computing the income of the foreign corporation.

For taxation years beginning after 2013, a Canadian branch will be denied a deduction for interest paid or payable on "outstanding debts to specified non-residents" to the extent that such debts exceed 1.5 times its "equity amount." In this regard,

- "Outstanding debts owing to specified non-residents" will include a loan used by the Canadian branch from any non-resident that does not deal at arm's length with the non-resident corporation (including a debt from the non-resident corporation itself); and
- The "equity amount" of the non-resident corporation will be 40 percent of the amount of the difference between:
 - The cost of its property used in carrying on

business in Canada, and

- The total of its debts outstanding (other than an outstanding debt to specified non-residents of the corporation).

Accordingly, a debt-to-asset ratio of 3:5 will apply for Canadian branches. This parallels the 1.5:1 debt-to-equity ratio used for Canadian subsidiaries (discussed below).

If the thin capitalization rule denies the deduction of interest expense by the Canadian branch, the non-resident corporation may bear additional branch tax liability. As branch tax and dividend withholding tax function similarly, the treatment of denied interest expense under the thin capitalization rule will be treated similarly for both branches and subsidiaries of non-resident corporations.



Operating in Canada through a subsidiary

Corporations organized under the laws of Canada or of a province of Canada are Canadian-resident corporations for the purposes of the ITA and therefore subject to tax in Canada on their worldwide income. All transactions between the Canadian corporation and its foreign parent or other related companies must take place on arm's length terms and conditions, and should be supported by contemporaneous transfer pricing documentation. Non-capital losses incurred by the corporation can be carried back for three taxation years or carried forward for 20 taxation years from the year in which the loss was incurred. Capital losses on the other hand can be carried back three taxation years and carried forward indefinitely.

Repatriation of profits

Dividends paid by a Canadian corporation to a non-resident **person** are subject to withholding tax at a statutory rate of 25 percent under Canadian domestic law. The domestic rate may be reduced to as low as 5 percent under Canada's tax treaties. Canada has an extensive tax treaty network, comprising some 92 treaties currently in force; however, this obviously leaves many foreign investors, or potential investors, without direct access to treaty benefits in their country of residence. A foreign investor in a non-treaty country may nevertheless be able to use an intermediary holding corporation in a treaty jurisdiction to avail itself of reduced rates of withholding tax on dividends paid from Canada or to reduce tax on a

future disposition. In order for the treaty-reduced dividend withholding tax rate to apply, the corporation incorporated in the treaty jurisdiction must be able to establish that it is resident under the treaty in that jurisdiction and is the beneficial owner of the dividend. The application of Canada's **general anti-avoidance rule (GAAR)** should also be considered.

Equity contributions made to the corporation in exchange for shares generally increase the corporation's paid-up capital balances, subject to the foreign affiliate dumping rules. Distributions made by a private Canadian corporation (which includes a subsidiary of a foreign public corporation) out of paid-up capital to a non-resident corporation are treated as a return of capital that is not subject to Canadian withholding tax. Distributions out of paid-up capital will, however, reduce the adjusted cost base of the shares and, as a result, may increase the gain otherwise realized on the sale of the shares of the corporation in the future. Unlike many other jurisdictions, Canada allows for distributions from paid-up capital before the payment of taxable dividends. Accounting capital is not the same as paid-up capital determined for tax purposes. Paid-up capital is based on legal stated capital, subject to certain adjustments under the ITA. Therefore, legal counsel should assist in determining stated capital and paid-up capital before the corporation makes a return of capital, to ensure that the amount distributed is paid-up capital and not deemed to be a dividend that is subject to withholding tax.

Financing

Interest expense paid or payable by a corporation on borrowed money used for the purpose of earning income from a business or property in Canada is deductible for Canadian tax purposes. The thin capitalization rules, however, may limit the deduction of interest paid by a corporation to non-resident parties that are related to the Canadian corporation, or that hold a substantial interest in the Canadian corporation.

In particular, the interest deduction of the Canadian corporation will be reduced to the extent that the corporation's ratio of interest-bearing debt owing to related non-resident persons to its equity held by related non-residents exceeds 1.5:1. A guarantee is not considered to be a loan for these purposes (however, see the discussion below regarding [Back-to-back loan arrangements](#)).

Non-participating interest payments made by a resident of Canada to foreign arm's length lenders are not subject to withholding tax. However, interest expenses denied pursuant to the thin capitalization rules are deemed to be dividends subject to Canadian withholding tax.

Where financing is to be obtained from related corporations, interest payments are subject to withholding tax at a statutory rate of 25 percent subject to reduction by an applicable tax treaty. The reduced rate varies, depending on the treaty, but is typically 10 percent or 15 percent. For non-participating interest payments made to US residents,

the withholding rate is reduced to zero under the Canada–US treaty. Foreign investors that wish to finance their Canadian operations from internal sources may be able to benefit from the exemption under the Canada-US treaty by providing the funds through a US-resident entity. However, such financing arrangements will be subject to the limitation-on-benefits article of the Canada–US treaty, GAAR, and to the back-to-back loan provisions. To qualify for the treaty rate, the ultimate parent must be publicly listed on a major US stock exchange and meet minimum trading requirements, or it must be majority-owned by US or Canadian residents. The zero withholding rate may also apply if the US entity carries on an active trade or business that is sufficiently similar and is substantial relative to the Canadian business. This may be the case where a multinational has operations in both countries.

Back-to-back loan arrangements

In an effort to curtail attempts to circumvent the thin capitalization and withholding tax rules through the use of intermediaries to facilitate financing of Canadian corporations, the Canadian government introduced legislation in 2014 to expand the existing anti-avoidance rule in the thin capitalization provisions and add a back-to-back loan provision to the withholding tax rules.

For thin capitalization purposes, the back-to-back loan rules apply where certain conditions are met.

The Canadian taxpayer must have certain outstanding debts or obligations to pay amounts to an intermediary (the taxpayer debt).

For the purposes of the thin capitalization rules, an intermediary does not include:

- A person resident in Canada with whom the taxpayer does not deal at arm's length;
- A non-resident person who owns (either alone or together with persons with whom that non-resident person is not dealing at arm's length) at least 25 percent of the votes or value of the Canadian corporation (a specified non-resident shareholder); or
- A non-resident person that does not deal at arm's length with a specified shareholder of the Canadian taxpayer; (the latter two persons are collectively referred to herein as the connected non-residents).

The intermediary (or a person that does not deal at arm's length with the intermediary) must also have an outstanding obligation owing to a connected non-resident ("intermediary debt") that meets either of the following conditions:

- Recourse in respect of the intermediary debt is limited in whole or in part to the taxpayer debt; or
- It can reasonably be concluded that all or part of the taxpayer debt became owing, or was

permitted to remain owing, because all or part of the intermediary debt was entered into or was permitted to remain outstanding.

The rules will also apply where the intermediary (or a person that does not deal at arm's length therewith) has a specified right in respect of a particular property that was granted directly or indirectly by a connected non-resident, and either:

- The existence of the specified right is required under the terms and conditions of the taxpayer debt; or
- It can reasonably be concluded that if the specified right were not granted, all or part of the taxpayer debt would not have been entered into or permitted to remain outstanding.



A specified right in respect of a property means a right to use, mortgage, hypothecate, assign, pledge or in any way encumber, invest, sell or otherwise dispose of, or in any way alienate, the property.

The rules will not apply unless the total of the outstanding intermediary debt and the fair market value of the property in which a specified right was granted in respect of a taxpayer debt is at least 25 percent of:

- The taxpayer debt; and
- All other amounts owed to the intermediary by the taxpayer or a person not dealing at arm's length with the taxpayer under the agreement, or a connected agreement, if the intermediary is granted security and the security secures the payment of the relevant debts.

The back-to-back loan rules target situations where the connected non-resident effectively funds 25 percent or more of the loan made by the intermediary to the Canadian taxpayer. While the *de minimis* threshold may permit a multinational group to make use of cross-collateralized loans and notional cash pooling arrangements, very strict conditions must be met or the back-to-back loan rules will be triggered.

Where the rules apply, all or a portion of the taxpayer debt is deemed to be owed directly by the Canadian taxpayer to the connected non-resident. Interest payable on the taxpayer debt is deemed payable to that person and the taxpayer debt becomes subject to the thin capitalization rules.

For withholding tax purposes, the back-to-back loan rules apply in a similar manner, except that the rules apply to back-to-back loans with all non-residents as there is no exclusion for connected non-resident intermediaries. Where the withholding tax payable to the intermediary is lower than the withholding tax payable to the non-resident person, the rules will apply to deem all or a portion of the loan to have been made directly for the purposes of determining the appropriate withholding tax rate.

Disposing of a Canadian subsidiary

Capital gains realized by non-residents on the sale of **taxable Canadian property** are subject to tax in Canada. Taxable Canadian property includes shares of a Canadian or a foreign corporation that derives its value principally from **Canadian resource properties**. A number of tax treaties exempt the sale of such shares from tax in Canada where the resource property is used by the corporation in its

business operations. This exemption, however, is not available in all treaties. In particular, it is not available in Canada's treaties with the United States and Japan. In these cases, it may again be possible to use an intermediary holding corporation in a treaty jurisdiction to reduce the Canadian taxes otherwise payable on the disposition of the shares, subject to Canadian anti-avoidance provisions. Luxembourg and the Netherlands are jurisdictions that have tax treaties with Canada containing this favourable provision, and are also otherwise favourable holding corporation jurisdictions.



Provincial royalties and other taxes

BRITISH COLUMBIA

The government of British Columbia levies royalties on oil and gas produced from Crown land, and it levies production taxes on oil and gas produced from freehold land. This government has various royalty programs and credits to encourage the development of oil and gas resources.

The BC government's Ministry of Finance administers the province's oil and gas royalties and its production taxes. Producers are liable for the payment of monthly royalties and taxes, and producers as well as facility operators are required to submit various reports in prescribed forms to the Ministry. The Ministry then assesses the reports, calculates the applicable royalties and taxes, and invoices the producers on a monthly basis.

Oil royalty

The oil royalty is determined by multiplying the royalty share by the average net value before taking applicable deductions.

A producer's royalty share for a well is calculated by multiplying the oil royalty rate by the monthly production volume, pro-rated based on the producer's ownership percentage. The oil royalty rate varies between 0 percent and 40 percent, depending on the production volume, the origin of the oil (Crown or

freehold), and the kind of oil the well produces (new oil, old oil, third tier oil, or heavy oil).

The average net value (on a per unit basis) is determined using the weighted average selling price from all sales during the month by the producer, less transportation cost and other allowable adjustments for the oil. If there is production but no sale for a particular month, there is no oil royalty imposed on the producer for that month.

Certain productions are exempted from oil royalty, including lost oil production and certain "discovery" oil productions.

Natural gas royalty

The net natural gas royalty is determined by taking the product of natural gas royalty rate, the marketable gas volume (the amount of gas that is available for sale measured at the plant inlet), and the reference price, and then applying the relevant deductions or royalty credits to the product.

The natural gas royalty rate varies between 5 percent and 27 percent, depending on the origin of the gas (Crown or freehold), the type of gas (conservation or non-conservation), the reference price, and the select price. A reduced rate is applied automatically for low productivity, Coalbed Methane ("CBM"), and marginal and ultra-marginal gas productions.

In addition, producers engaged in high-risk and high-cost oil and gas developments can apply for a lower rate under the British Columbia Government's Net Profit Royalty Program.

The reference price is the greater of the producer's actual sale price (reduced by the cost allowance for processing and transmission) and the posted minimum price set by the Ministry of Energy and Mines.

The gross royalty is reduced by a Producer Cost of Service Allowance (PCOS). This reduction is intended to compensate producers for the costs associated with the field-gathering, dehydration, and compression of gas. There are, in addition, a number of royalty credits and programs available to offset royalty liabilities, as discussed below.

Byproducts recovered from the production of natural gas, such as natural gas liquids and sulphur, like natural gas, are also subject to royalties.

Deep royalty programs

The BC Government provides three different credits for deep gas well explorations and productions: the *deep discovery well exemption*, the *deep well credit*, and the *deep re-entry credit*. The deep discovery well exemption relieves producers that are drilling deep discovery wells from the requirement to pay royalties. The deep well credit reduces the royalty payable,

depending on the depth and type of well. The deep re-entry credit incentive also reduces royalty payable and is based on the depth of the well event and the amount of incremental drilling done to date. The deep well credit and the deep re-entry credit cannot be claimed simultaneously.

Effective April 1, 2014, deep gas wells are classified as either tier 1 or tier 2 wells. Deep well producers whose net royalty payable is zero after having claimed the deep well credit or the deep re-entry credit are subject to a 6 percent (tier 1 wells) or 3 percent (tier 2 wells) minimum royalty.

Coalbed methane (CBM) Royalty program

This program is intended to encourage the development of BC's **coalbed methane** resources by reducing the royalty payable by producers of this kind of natural gas. The amount of credit granted to a producer under this program depends on the rate of production from the producer's well, on the producer's additional PCOS allowance, and on the value of the credits already granted for each coalbed methane well drilled.

Infrastructure development credit

This credit is intended to encourage oil and gas companies to invest in new oil and gas roads and pipeline projects and to improve year-round access to oil and gas resources in BC. It can be worth as much as 50 percent of the costs incurred in the construction of roads, pipelines, and related facilities.

Other natural gas exemptions

BC provides producers of natural gas with various other exemptions from gas royalty, in addition to the deep discovery well exemption discussed above, including those for lost gas productions, for discontinued well productions, and for gas by-products used for oil and gas productions.

Other oil and gas related levies or taxes

Oil and gas producers in BC are also subject to a range of regulatory levies and taxes commissioned by the BC Oil and Gas Commission.

Beginning January 1, 2017, producers who conduct liquefaction activities at a Liquefied Natural Gas ("LNG") facility in BC will be subject to LNG income tax. The LNG income tax is to be determined on a facility-by-facility basis, and a LNG income tax return must be filed on an annual basis.

The LNG income tax is a two-tier tax. The tier 1 tax at a rate of 1.5 percent is applicable on LNG net operating income from liquefaction activities before the recovery of capital investment costs. Such tax paid is accumulated in a pool to be applied against the tier 2 tax on LNG net income at a higher rate of 3.5 percent (which will increase to 5 percent in 2037 and thereafter) when the facility becomes profitable. The LNG net income is based on LNG net operating income, minus deductions for net operating loss account and capital investment account.

In the taxation year of permanent closure of a LNG facility, producers may claim the closure tax credit, which is a refundable tax credit based on eligible expenditures incurred during the process of permanently closing the facility, to the extent of total LNG income taxes paid on net income over the life of the facility.

ALBERTA

The government of Alberta collects royalties from oil and gas operations on Crown land that are exploring for, extracting, producing, and selling oil and gas. These royalties are deductible for income tax purposes.

Modernized royalty framework

The Modernized Royalty Framework was introduced on July 11, 2016 for crude oil, liquid and natural gas, and non-project crude bitumen wells spud on or after January 1, 2017. Companies will have to pay a flat royalty rate of 5 percent on a well's early production until the well's total revenue from all hydrocarbon products equals the drilling and completion cost allowance, which is a proxy for well costs based on the average industry drilling and completion costs based on a function of the well's true vertical depth, total lateral length, and total proppant placed. After this threshold is reached, royalty rates of up to 40 percent will apply. The modernized royalty framework will not impact royalties on production from an approved oil sands royalty project.

New wells spud before January 1, 2017 that qualify may elect for early opt-in to the modernized royalty framework by applying in writing to the Executive Director of Royalty Operations. To qualify, new wells must:

- be spud after July 12, 2016;
- represent additional capital investment, and;
- it can be demonstrated the well would not otherwise be drilled in 2016.

New wells that did not meet the criteria will continue to operate under the previous royalty framework until December 31, 2026.

PREVIOUS ROYALTY REGIME

Natural gas royalty

The **royalty** rate payable by producers of natural gas depends on the energy content of the natural gas produced. Natural gas stream components typically include methane, ethane, propane, butane(s), and pentanes-plus. The producer's royalty obligation is calculated by applying the natural gas royalty rate to the contents of the natural gas stream on a monthly basis. The natural gas royalty rate is referred to as the Well Event Average Royalty Rate (**WEARR**) and is set monthly for each well event. WEARR is calculated by taking the weighted average royalty rates for

components in the natural gas stream at the particular well event. Between January 1, 2011 and December 31, 2016, royalty rates range from a combined 5 percent to 36 percent of net revenue. The Alberta government collects natural gas royalties in the form of cash payment and not in-kind.

Horizontal well rate

The Alberta government provides a Horizontal Gas New Well Royalty Rate to encourage the deployment and development of **horizontal drilling** technologies. This rate is 5 percent and is restricted to a maximum of 18 months' production and a volume cap of 7,949 m³ oil equivalent. For a well event to qualify for this rate, the following conditions must apply:

- the well event must be identified as a horizontal one according to the records of the Energy Resources Conservation Board (**ERCB**);
- the well event must have a Crown interest greater than zero; and
- the spud date is on or after May 1, 2010.

Shale gas

The Alberta government provides a shale gas new well royalty rate of 5 percent. This royalty rate is designed to accelerate research into the province's shale gas resources and, ultimately, to achieve commercial natural gas production from shale deposits.

To qualify, a well event must have:

- a fluid code of "Shale Gas Only" when it commences production,
- no production prior to May 1, 2010, and
- a Crown interest greater than zero when it commences production.

The cap for the shale royalty is 36 production months. There is no volume cap. All qualifying shale well events in a well contribute to a single shale gas cap.

Coalbed methane (CBM)

Alberta has a large resource base of **coalbed methane**, which is estimated to constitute over 500 trillion cubic feet. While there has been some initial development of these reserves, the deeper coal tends to contain saline water that complicates production and, consequently, hinders the economic viability of developing the resource. For this reason, the government of Alberta has extended the 5 percent front-end royalty rate for wells of this type, which have to undergo the de-watering phase. This rate is known as the coalbed methane new well royalty rate. To qualify for this royalty rate, the well event must have:

- a fluid code of "Coalbed Methane–Coals Only" when it commences production,

- no production prior to May 1, 2010, and
- a Crown interest greater than zero when it commences production.

Wells that have prior production do not qualify. The cap is 36 production months, or a Crown production cap of 11,924 m³ oil equivalent. All qualifying coalbed methane well events in the well contribute to a single coalbed methane new well royalty rate cap.

Conventional oil

The royalty rate applicable to **conventional oil** is based on a single sliding scale and is dependent upon the production volume, the price of the product, and the quality of the oil produced. Royalty rates are calculated monthly and can range from 0 percent to 40 percent. The royalty rate for new wells is set at 5 percent. This rate applies for the new well's first 12 production months and is capped at a production volume of 50,000 barrels of oil.

The Alberta government collects crude oil royalties in kind and markets the oil on behalf of the Crown.

Oil sands

Alberta's royalty regime for oil sands projects is based on a sliding scale. The rate depends on the current price of oil, on the financial status of the project, and on whether payout has been achieved. Payout

is the point at which the developer has recovered all of the allowable costs. The sliding scale has been implemented to allow for different rates to be applied to pre-payout and post-payout production. The applicable rates before January 1, 2017 are as follows:

- The royalty before payout is calculated as 1 percent to 9 percent of gross revenue (project revenue).
- The royalty after payout is the greater of 1 percent to 9 percent of gross revenue and 25 percent to 40 percent of net revenue (project revenue less allowable costs).

The base royalty or base net royalty is increased for every dollar that the world oil price, as reflected by West Texas Intermediate (WTI), rises above \$55 per barrel, to a maximum of \$120, as outlined above.

SASKATCHEWAN

The government of Saskatchewan collects royalties from oil and gas operations on Crown land that are exploring for, extracting, producing, and selling oil and gas. As in Alberta, these royalties are deductible for income tax purposes.

Natural gas royalties

The Crown royalty rate applicable to natural gas in Saskatchewan depends on the productivity of each well and on the type of gas produced; this rate is then

adjusted based on the current provincial average gas price. Using a prescribed formula, the producer will calculate the percentage of the production volumes from each well that will be payable on a monthly basis in royalties to the Crown. This Crown royalty volume is then translated into a dollar value by multiplying the Crown royalty volume determined for each well by the wellhead value of the gas for the month. To calculate the wellhead value of the gas, the provincial average gas price or the operator average gas price can be used, less the allowable gas cost allowance of \$10 per thousand m³.

Gas is categorized according to when the well was drilled. The classification system is as follows:

- Old gas is gas produced from a gas well drilled prior to October 1, 1976.
- New gas is gas produced from a gas well drilled on or after October 1, 1976.
- Third tier gas is gas produced from a gas well drilled on or after February 9, 1998.
- Fourth tier gas is gas produced from a gas well drilled on or after October 1, 2002.

The applicable Crown royalty rates will vary according to the type of gas the well is producing. The formulas used to calculate these rates can be found in Information Circular PR-IC02 on the Government of Saskatchewan

website at www.gov.sk.ca. For example, if a well's monthly gas production is 250,000 m³, one of the following royalty rates will apply:

- Old gas – 20 percent of the first \$35 of the price and 45 percent of the remaining price;
- New gas – 15 percent of the first \$35 of the price and 35 percent of the remaining price;
- Third tier gas – 15 percent of the first \$50 of the price and 35 percent of the remaining price; and
- Fourth tier gas – 5 percent of the first \$50 of the price and 30 percent of the remaining price.

Gas royalty programs

Exploratory drilling incentive

To encourage exploratory drilling, the Saskatchewan government provides an Exploratory Drilling Incentive. This incentive permits a 2.5 percent royalty rate for the first 25 million m³ of natural gas produced from a qualifying exploratory well. To qualify for this incentive, the gas well must meet various criteria as outlined in Information Circular PR-IC04 (available, as mentioned above, on the Government of Saskatchewan website).

Oil royalties

In Saskatchewan, the **Crown royalty** rate applicable to conventional oil depends on the well's productivity and on the type of oil being produced. This rate is then adjusted based on the level of the reference oil price set by the government for each type of oil.

Using a prescribed formula, the producer calculates the percentage of the production volumes from each well that will be payable on a monthly basis in royalties to the Crown. This Crown royalty volume is then translated into a dollar value by multiplying the Crown royalty volume determined for each well by the wellhead value of the oil for the month. To calculate the wellhead value of the oil, the actual price received by the producers at the point of sale is used, less certain eligible transportation expenses.

Oil is categorized according to where and when the well that produced the oil was drilled. Oil is categorized as *heavy oil*, *southwest-designated oil*, or *non-heavy oil*. Heavy oil is all oil produced in the Lloydminster and Kindersley-Kerrobert areas – except for oil produced from the Viking zone. Southwest-designated oil is oil produced from wells drilled on or after February 9, 1998 as well as incremental oil produced from water floods commencing operation on or after February 9, 1998 in the southwest area of the province. Non-heavy oil is all other oil – in other words, oil that is neither heavy oil nor southwest-designated oil.

Each of these three types (heavy oil, southwest-designated oil, and non-heavy oil) is further subdivided into new oil, third tier oil, and fourth tier oil. New oil is oil produced from an oil well drilled on or after January 1, 1974. Third tier oil is oil produced from an oil well drilled on or after January 1, 1994. Fourth tier oil is oil produced from an oil well drilled on or after October 1, 2002. Non-heavy oil includes a fourth

subcategory – old oil. Old oil is non-heavy oil produced from an oil well drilled prior to 1974.

The royalty formulas for oil in Saskatchewan are based on the following principle: the government retains a base royalty rate on a base price plus a marginal royalty rate on the price that exceeds the base price. This program is applied at a fixed reference well-production rate. The Crown royalty rates applicable to each type of oil range from 5 percent to 45 percent of production volumes, as illustrated in Table 3.

Oil royalty programs

Vertical well drilling incentives

Certain vertical oil wells drilled on or after October 1, 2002 are subject to a reduced royalty rate of 2.5 percent on a fixed amount of production. Depending on the type of vertical well drilled, the volume of oil subject to the reduced royalty rate varies between 4,000 and 16,000 m³. The type of vertical well depends on the nature of the drilling (i.e., exploratory or development) and on the depth of the drilling.

Horizontal well drilling incentives

Horizontal oil wells drilled on or after October 1, 2002 are likewise subject to a reduced royalty rate of 2.5 percent on a fixed amount of production. Depending on the type of horizontal well drilled, the volume of oil subject to the reduced royalty rate varies between 6,000 and 16,000 m³. The type of horizontal well depends on the depth of the drilling.

Table 3: Oil – Crown royalty rates

	Base royalty rate	Base price	Marginal royalty rate	Reference well
Heavy oil				
New oil	10%	\$50/m ³	25%	100 m ³ /month
Third tier oil	10%	\$100/m ³	25%	100 m ³ /month
Fourth tier oil	5%	\$100/m ³	30%	250 m ³ /month
Southwest designated				
New oil	12.5%	\$50/m ³	35%	100 m ³ /month
Third tier oil	12.5%	\$100/m ³	35%	100 m ³ /month
Fourth tier oil	5%	\$100/m ³	30%	250 m ³ /month
Non-heavy oil				
Old oil	20%	\$50/m ³	45%	100 m ³ /month
New oil	15%	\$50/m ³	35%	100 m ³ /month
Third tier oil	15%	\$100/m ³	35%	100 m ³ /month
Fourth tier oil	5%	\$100/m ³	30%	250 m ³ /month

Source: www.energy.alberta.ca/Tenure/pdfs/FISREG.pdf

MANITOBA

The government of Manitoba collects royalties from oil and gas operations on Crown land that are exploring for, extracting, producing, and selling oil and gas. As in other provinces, the royalties charged are not considered a tax.

Natural gas royalties

The Crown royalty rate applicable to natural gas is equal to 12.5 percent of the volume sold, calculated for each production month.

Oil royalties

The Crown royalty rates applicable to conventional oil depend on the productivity of each well and on the type of oil produced. With respect to royalties, oil produced in Manitoba is categorized as either old oil, new oil, third tier oil, or holiday oil. The classification scheme is as follows:

- Old oil is oil that is produced from a well drilled prior to April 1, 1974.
- New oil is oil that is produced from:
 - a well drilled on or after April 1, 1974 and prior to April 1, 1999;
 - an abandoned well re-entered on or after April 1, 1974 and prior to April 1, 1999;
 - an old oil well that, in the opinion of the Director, can be reasonably attributed to an increase in reserves from an enhanced recovery project implemented after April 1, 1974 and prior to April 1, 1999; or
 - a horizontal well.
- Third tier oil is oil produced from:
 - a vertical well drilled on or after April 1, 1999;

- an abandoned well that is re-entered on or after April 1, 1999; oil produced from an inactive well, activated after April 1, 1999;
- a *marginal well* that has undergone a *major workover*; or
- an old oil well or new oil well that, in the opinion of the Director, can be reasonably attributed to an increase in reserves from an enhanced recovery project implemented under *The Oil and Gas Act* after April 1, 1999.
- Holiday oil is oil that is exempt from any royalty payable under the *Crown Royalty and Incentives Regulation* and from any tax payable under the *Oil and Gas Production Tax Regulation*. However, wells drilled or receiving a *marginal well major workover incentive* after December 31, 2013 and prior to January 1, 2019, have a requirement to pay a minimum royalty on Crown production.

Oil royalties are based on the production volumes from each spacing unit or unit tract, on a monthly basis. The Crown royalty rates, expressed as a percentage of production, are illustrated in Table 4.

For wells drilled after December 31, 2013 and before January 1, 2019, there will be a minimum Crown royalty. Based on specific monthly volumes and well type, the Crown royalty will be the lesser of

- 3 percent of oil produced; and
- Crown royalties otherwise payable if the oil was not considered holiday oil.

Table 4: Manitoba Oil – Crown royalty rates

Production (m ³ /month)	Third Tier Oil	Third Tier holiday	New oil	New oil Holiday	Old oil	Pre MDIP 2014 holiday
0	0.0	0.0	0.0	0.0	0.0	0.0
20	0.0	0.0	0.0	0.0	0.0	0.0
30	0.0	0.0	0.0	0.0	4.7	0.0
40	0.0	0.0	1.1	1.0	9.0	0.0
50	1.7	1.0	3.4	1.0	13.3	0.0
60	3.3	1.0	5.7	1.0	17.6	0.0
70	4.4	1.0	7.9	1.0	21.3	0.0
80	5.2	1.0	9.3	1.0	24.0	0.0
90	5.8	1.0	10.5	1.0	26.1	0.0
100	6.4	1.0	11.4	1.0	27.8	0.0
150	7.9	1.0	14.1	1.0	32.8	0.0
200	8.7	1.0	15.5	1.0	35.3	0.0
250	9.1	1.0	16.3	1.0	36.8	0.0
300	9.5	1.0	16.9	1.0	37.8	0.0
350	9.7	1.0	17.2	1.0	38.5	0.0
400	9.8	1.0	17.5	1.0	39.0	0.0
450	10.0	1.0	17.8	1.0	39.4	0.0
500	10.1	1.0	18.0	1.0	39.8	0.0
550	10.2	1.0	18.1	1.0	40.0	0.0
600	10.2	1.0	18.2	1.0	40.3	0.0

Source: www.gov.mb.ca/iem/petroleum/regime/regime2014.doc

Manitoba drilling incentive program (MDIP)

The Manitoba Drilling Incentive Program (MDIP) allows the licensees of newly drilled wells or of qualifying wells where a major workover has been completed to claim a volume of the oil produced as holiday oil. In order to be designated as holiday oil, the oil volumes must be produced within 10 years of the finished drilling date of a newly drilled well, or within 10 years of the completion date of a major workover on a marginal well. Production from these wells will be subject to a minimum Crown royalty rate or to minimum production tax. The MDIP consists of seven components:

- 1 Vertical well incentive
- 2 Exploration and deep well incentive
- 3 Horizontal well incentive
- 4 Marginal well major workover incentive
- 5 Pressure maintenance project incentive
- 6 Solution gas conservation incentive
- 7 Holiday oil volume account

The specific requirements of each of these incentives can be found in the *Manitoba Petroleum Fiscal Regime* report, available from the Government of Manitoba website (www.gov.mb.ca).

NOVA SCOTIA

The Nova Scotia Department of Finance collects royalties from oil and gas operations on Crown land that are exploring for, extracting, producing, and selling oil and gas. The provincial government has regimes in place for both onshore and offshore development of petroleum resources. As in other provinces, the royalties imposed and collected are not classified as an income tax.

Onshore oil and gas royalties

Nova Scotia has a generic royalty regime for all onshore petroleum resources (except coal gas). All petroleum produced in the province is subject to a royalty equal to 10 percent of the fair market value of the petroleum at the wellhead produced each month. When determining the royalties to be paid on any petroleum other than oil, an allowance for the cost of processing or separation can be deducted as determined in each particular case by the Minister. In the case of lands that have been leased from the government and that are subject to an exploration

agreement, no royalty will be payable on any oil or gas produced on that land for a period of two years from the date of commencement of the lease.

All coal gas produced under the authority of a coal gas production agreement is subject to a royalty of 5 percent of the fair value of the coal gas produced each month.

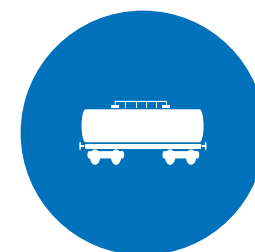
Offshore oil and gas royalties

Nova Scotia has a generic royalty regime for all offshore petroleum resources (except those projects with special arrangements). This regime is a four-tier system that increases the royalty percentage payable as the payout and profitability of the project increase. The royalties payable are calculated as follows:

- Tier 1 – 2 percent of gross revenues until simple payout return allowance, based on 5 percent of the Long Term Government Bond Rate, is reached;
- Tier 2 – 5 percent of gross revenues until simple payout return allowance based on 20 percent of the Long Term Government Bond Rate is reached;
- Tier 3 – 20 percent of net revenue until simple payout return allowance based on 45 percent of the Long Term Government Bond Rate is reached;
- Tier 4 – 35 percent of net revenue.

“Simple payout” occurs at the point where project revenues first reach or exceed the sum of allowed exploration costs, capital costs, operating costs, and royalties paid. Corporate income taxes are not an allowable cost for royalty purposes. The “return allowance” is a percentage of unrecovered project costs. Once simple payout is reached, the return allowance ceases to be calculated.

Incentive regimes are provided for projects considered “small oil” or high risk. Both attract a royalty regime that is similar to the generic regime outlined above, but has a few modifications.



NEWFOUNDLAND

Newfoundland and Labrador has one regulatory system for its onshore oil and gas resources, and another for its offshore resources. Resource development onshore is regulated by the province's *Petroleum and Natural Gas Act*, while offshore petroleum resources are jointly managed by the federal and provincial governments through the Canada-Newfoundland and Labrador Petroleum Board.

Onshore oil and gas royalties

Newfoundland and Labrador has a generic onshore royalty regime for all onshore petroleum resources. There are no royalties payable (i.e., a royalty holiday) on the first 2 million barrels or equivalent of production from a project. After the first 2 million barrels or equivalent of production, a *basic royalty* of 5 percent of gross revenue is payable. Further, an additional *net royalty* becomes payable after *net royalty payout* occurs. Net royalty payout occurs when the costs related to a particular project are recovered, plus a specified return allowance on those costs. This additional net royalty consists of a two-tier profit-sensitive royalty, calculated as follows:

- Tier 1: 20 percent of the net revenue after a return allowance is achieved of 5 percent plus the long

term government bond rate. The basic royalty is a credit against this royalty. Therefore, the total royalty owing is the higher of the basic royalty or the tier 1 net royalty.

- Tier 2: 5 percent of net revenue after a return allowance is achieved of 15 percent plus the long term government bond rate. The Tier 2 net royalty is in addition to any other royalties payable.

Offshore natural gas royalties

The province's offshore natural gas royalty regime consists of two components, basic royalties and net royalties. The basic royalty is based on project production and the royalty rates are driven by the netback value of production. The higher the netback price earned, the higher the royalty rate. The minimum basic royalty rate is 2 percent and the maximum basic royalty rate is 10 percent. The net royalty is based on project cost recovery. The net royalty rate is driven by the projects cumulative revenue to cumulative costs ratio. The minimum net royalty rate is 0 percent and the maximum net royalty rate is 50 percent. The net royalty percentage is then applied to revenues net of transportation costs, project capital and operating costs, and basic royalties paid.

Offshore oil royalties

The province's offshore oil royalty regime is similar to the offshore natural gas royalty regime in that there are basic royalties as well as net royalties based on project cost recovery. The basic royalty rates depend on how much of a project's costs have been recovered. Starting in the first month in which oil is produced and continuing until costs recovered and profitability (as measured by the revenue over cost index calculation, the "R Factor") reaches 25 percent, 1 percent of revenues less transportation costs are payable as royalties. Depending on the R Factor achieved, the basic royalty rates go up to a maximum of 7.5 percent. Further, an additional net royalty becomes payable after project costs are completely recovered. The net royalty rate ranges from 10 percent to 50 percent depending on the cumulative revenues and costs incurred. The net royalty rate is applied to revenues net of transportation, capital, and operating costs.



YUKON

The Yukon Territory introduced oil and gas royalty regulations in February 2008, authorizing the government of Yukon to collect royalties for oil and gas recovered from Crown lands. The base oil and gas royalty rate is equal to 10 percent of production and increases to a maximum of 25 percent based on a price-sensitive formula. During an initial period, during the royalty rate is kept to 2.5 percent; it remains there until certain production thresholds are met.

NORTHWEST TERRITORIES AND NUNAVUT

Natural resources in Canada are owned by the provinces, and therefore the royalties charged on natural resource production fall under provincial jurisdiction. With the exception of the Yukon, natural resources in areas that are not provinces or are not subject to special agreement, such as the Northwest Territories and Nunavut, fall under federal jurisdiction.

Federal royalties applicable to natural resource production are categorized as relating to either frontier lands or reserve lands. Royalties on frontier lands are governed by the *Canadian Petroleum Resources Act*, while royalties on reserve lands are governed by the *Indian Oil and Gas Act* (IOGA).

Frontier land oil and gas royalties

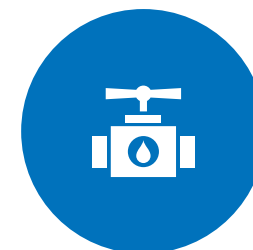
The federal government administers the royalty program relating to Crown land (i.e., frontier land) in Nunavut and the Northwest Territories. The Minister of Aboriginal Affairs and Northern Development manages the oil and gas rights on lands north of 60 degrees. Oil and gas projects on frontier land are subject to a 1 percent royalty rate on gross revenues at start up, and this increases by 1 percent every 18 production months to a maximum of 5 percent or until payout is reached. After payout, the royalty is calculated as the greater of 30 percent of net revenues or 5 percent of gross revenues.

Reserve land oil and gas royalties

The federal government holds the reserve lands for the benefit of and use by native bands. The IOGA allows for special royalty arrangements. There are many examples of special royalty arrangements within Canada. A detailed summary of them is beyond the scope of this book.

OTHER PROVINCES

We have provided a summary of the oil and gas taxation systems in Canadian provinces that have significant oil and gas operations. We have not done so for the provinces – Québec, Ontario, New Brunswick, and Prince Edward Island – that have limited oil and gas activity. Should you require information regarding taxation in these provinces, please contact your KPMG adviser for assistance.



Other taxes

Resource development activities in Canada may be subject to other federal and provincial taxes, in addition to the taxes on income described in the preceding sections of this book. These additional taxes include value-added and sales taxes, customs duties, and land transfer taxes or registration fees. A brief summary of these types of levies is provided below.

VALUE-ADDED AND SALES TAXES

Federal

The federal government levies a form of value-added tax known as the goods and services tax (**GST**). The current GST rate is 5 percent and applies to a broad range of goods and services supplied in Canada, with certain specified exceptions. Goods and services that are not subject to 5 percent GST may be zero-rated (that is, taxable at 0 percent) or exempt (not taxed).

In common with most value-added tax regimes around the world, the GST applies at each stage of the production and distribution of goods and services; however, it is fully recoverable to the supplier at each stage up to purchase of the supply by the final consumer. Thus, it is the final consumer who ultimately bears the tax. The recovery mechanism is the availability of an input tax credit for GST incurred on expenditures.

Five provinces – Ontario, Prince Edward Island, New Brunswick, Nova Scotia, and Newfoundland and Labrador – have repealed their provincial sales taxes

(PST) and have harmonized their sales tax regimes with the GST. These provinces have adopted a single harmonized sales tax (**HST**) consisting of a federal and a provincial component. Both components of the HST are recoverable by suppliers, with some exceptions.

For a time, British Columbia also had an HST; however, the British Columbia government reversed its decision to harmonize and reinstated a separate PST, effective April 1, 2013. British Columbia's current PST is substantially the same as the one it repealed in July 2010.

Provincial

Three provinces – Saskatchewan, Manitoba, and British Columbia – currently levy a PST under provincial statutes that operate independently from the federal GST legislation. These provincial sales taxes are similar to the sales and use taxes levied in many US states. PST typically applies to sales and leases of goods and to certain services at the retail level (subject to various exemptions). Unlike GST/HST, PST incurred by businesses is not recoverable.

Québec levies its own form of value-added tax, the Québec sales tax (**QST**). Like the GST/HST, the QST applies to a broad range of goods and services at each stage of production and distribution, and it is recoverable by the supplier as an input tax refund in the same manner as the GST/HST input tax credit. The QST applies in much the same manner as the GST.

Alberta, Yukon, the Northwest Territories, and Nunavut do not currently impose separate sales taxes. Supplies of goods and services in these jurisdictions are subject to GST.

Table 5 shows the federal and provincial rates for value-added and sales taxes in effect in 2017.

Table 5: Value-added and sales tax rates, Canada, as at October 1, 2017

Province	Sales tax rate
British Columbia	5 percent GST + 7 percent PST
Alberta	5 percent GST
Saskatchewan	5 percent GST + 6 percent PST
Manitoba	5 percent GST + 8 percent PST
Ontario	13 percent HST
Québec	5 percent GST + 9.975 percent QST
New Brunswick	15 percent HST
Nova Scotia	15 percent HST
Prince Edward Island	15 percent HST
Newfoundland and Labrador	15 percent HST
Yukon	5 percent GST
Northwest Territories	5 percent GST
Nunavut	5 percent GST

Saskatchewan's 2017 budget increased the PST rate to 6% effective March 23, 2017.

Application to the oil & gas industry

GST/HST and QST

The oil and gas industry is subject to the same GST/HST and QST rules as other businesses. GST/HST and QST apply to inputs (acquisitions of materials/products and services) and outputs (supplies of products and services made to others) in the course of exploration, development, and operation. As discussed above, the rate of tax that applies depends on the province in which the oil and gas operations take place. For example, in 2017, expenditures incurred by an oil and gas business will attract 13 percent HST in Ontario, 14.975 percent combined GST and QST in Québec, and 5 percent GST in Alberta and the three territories.

While GST/HST incurred is recoverable through input tax credit claims, large businesses (those with annual revenues over \$10 million) are not entitled to recover the provincial portion of the HST incurred in Ontario and PEI on expenditures in the following categories:

- energy (excluding energy used in production);
- telecommunications (other than internet access and toll-free number charges);
- vehicles under 3,000 kg and fuel used in such vehicles (excluding diesel); and
- meals and entertainment, to the extent that these expenses are restricted for income tax purposes.

These restrictions were introduced when Ontario's HST came into effect on July 1, 2010; beginning in 2015 these restrictions began to be phased out as shown in the table below. PEI adopted these rules as well when the HST in that province became effective on April 1, 2013.

Since July 1, 2015 the RITC requirement in Ontario is being gradually phased out by reducing the recapture rate over the following years:

Day on which the provincial part of the HST becomes payable without having been paid or is paid without having become payable	Ontario RITC recapture rate
July 1, 2010 to June 30, 2015	100 percent
July 1, 2015 to June 30, 2016	75 percent
July 1, 2016 to June 30, 2017	50 percent
July 1, 2017 to June 30, 2018	25 percent
July 1, 2018 and beyond	0 percent

In Québec, large businesses (those with annual revenues in excess of \$10 million) are not entitled to claim an input tax refund for the QST incurred on the same categories of expenditures listed for Ontario and PEI above. Québec will phase out these restrictions on the same basis as Ontario as part of its plan to make the QST operate in the same manner as the

GST in virtually all respects. The phase-out schedule will be as follows:

Day on which the QST becomes payable without having been paid or is paid without having become payable	Québec RITR recapture rate
Before December 31, 2017	100 percent
January 1, 2018 to December 31, 2018	75 percent
January 1, 2019 to December 31, 2019	50 percent
January 1, 2020 to December 31, 2020	25 percent
January 1, 2021 and beyond	0 percent

The rate of GST/HST that applies to the sale of petroleum products depends on the shipping destination of the product. Where the shipping destination is in Canada, the GST/HST rate that applies is the rate applicable in the province/territory to which the product is shipped. Petroleum product shipped to a destination outside Canada is zero-rated (taxable at 0 percent).



The QST applies to petroleum products shipped to a destination in Québec. Petroleum products shipped to a destination outside Québec are zero-rated for QST purposes.

PST

British Columbia

Effective April 1, 2013 British Columbia's 7 percent PST applied to goods and certain services (repair and maintenance, telecommunications, and legal services) acquired for use in that province. Most of the exemptions that existed prior to July 1, 2010 under the "old" PST apply under the new PST and include:

- machinery and equipment used exclusively in the exploration for, discovery of, or development of petroleum or natural gas; and
- machinery and equipment used primarily in the extraction or processing of petroleum or natural gas.

The sale of petroleum products in British Columbia is subject to PST unless the product is acquired for resale, export or further processing.

Saskatchewan

Saskatchewan's 6 percent PST applies to goods and a variety of services acquired for use in that province. All equipment and materials acquired for use in exploration, development, and operation of oil and gas wells are subject to PST unless a specific exemption applies.

Specific exemptions are provided for:

- equipment designed for and used exclusively in geophysical exploration; and
- equipment designed for and used exclusively in exploration and development of an oil well.

The sale of oil products in Saskatchewan is subject to PST unless the product is acquired for resale, export or further processing.

Manitoba

Manitoba's 8 percent PST applies in a similar manner to Saskatchewan's PST. All equipment and materials acquired for use in oil and gas exploration, development, and operation are subject to PST unless a specific exemption applies. The exemptions include the following materials and equipment:

- prescribed equipment used in oil and gas exploration or geophysical exploration, and
- drill bits and explosives used in mineral exploration or development.

Manitoba also provides an 80 percent reduction in the rate of PST on electricity used in petroleum production.

The sale of petroleum products in Manitoba is subject to PST unless the product is acquired for resale, export, or further processing.

CUSTOMS DUTIES

Canada's *Customs Act* defines duties to mean "any duties or taxes levied or imposed on imported goods under the *Customs Tariff*, the *Excise Act, 2001*, the *Excise Tax Act*, the *Special Import Measures Act* or any other Act of Parliament." Therefore, imported commercial goods are subject to both import duty and the GST.

Customs duty is assessed on the basis of the tariff classification of the imported goods and the corresponding duty rates set out in the *Customs Tariff*. The most favoured nation (**MFN**) rates apply unless the imported goods are eligible for preferential tariff treatment based on their country of origin. The MFN rates of duty usually range from free to 8 percent on machinery and equipment used in production.

The following summary highlights a few key areas relating to oil and gas.



Machinery and equipment

The federal government implemented measures to eliminate tariffs on a wide range of manufacturing inputs, machinery, and equipment imported into Canada. The MFN rates of duty on these items were gradually reduced to free by January 1, 2015.

There are various other provisions in the *Customs Tariff* that may also be considered if the imported goods attract customs duty. For example, there are special provisions that provide relief of customs duty on certain goods used in specific oil and gas applications.

End use provisions

The *Customs Tariff* provides duty relief to certain goods (machinery, equipment and production material) that are imported into Canada for use in activities relating to the development, maintenance, testing, depletion, or production of oil or natural gas wells. Likewise eligible for duty relief under this Act are materials that are for use in the manufacture of certain machinery and equipment that are employed in the exploration, maintenance, testing, depletion, or production of oil or natural gas.

Temporary importations

Certain provisions in the *Customs Tariff* allow machinery and equipment to be imported free of customs duty if they are being imported only temporarily for use in Canada. To qualify for these provisions, the goods must be exported within a certain time frame and cannot be imported for sale, lease (the imported goods can be leased to the importer but the importer cannot lease the goods to another party in Canada), further manufacturing, or processing (among other conditions). Full or partial relief of the GST may be available for these temporarily imported goods, depending on what they are and what they are to be used for while in Canada. If the goods do not attract duty upon full importation and no relief from the GST is available, there is no benefit to entering the goods under these provisions.

CAPITAL TAX

Canada no longer imposes a federal **capital tax**. In addition, all provinces, with the exception of Saskatchewan, have eliminated corporate capital tax on resource companies.

Although Saskatchewan's capital tax base rate was eliminated on July 1, 2008, large resource companies

in Saskatchewan continue to be subject to a capital tax surcharge – the **resource surcharge** – equal to 1.7 percent (wells drilled after September 30, 2002), or 3.0 percent (wells drilled before October 1, 2002) of the value of sales of oil and gas produced in the province. Provincial capital tax is deductible in computing taxable income.

LAND TRANSFER TAXES

Most of the provinces impose land transfer taxes on transfers of real property – land, buildings, and other improvements. The rates of land transfer tax vary by province and range from 0.25 percent to 2.00 percent of the consideration for the real property transferred. Certain exemptions from land transfer taxes apply to non-arm's length transactions. In addition, transfers of resource properties are in many cases exempt from land transfer tax.

No stamp or transfer duties are payable on the transfer of shares. Some of the provinces may impose land transfer tax if a transfer of shares occurs within a certain period after the transfer of real property that was eligible for a non-arm's length exemption.

Carbon pricing in Canada

Carbon pricing in Canada has been steadily evolving over the past number of years. Currently British Columbia and Alberta have implemented carbon pricing regimes that impact the consumption of fossil fuels in those provinces and Ontario and Québec have adopted Cap and Trade regimes, not covered herein, that are harmonized with other jurisdictions outside Canada. Through these four jurisdictions, a full 90 percent of Canadians are impacted by a price on carbon. The federal government has announced that it will impose a minimum price on carbon emissions upon the provinces that do not have an equivalent carbon regime, which will begin at \$10 per tonne of CO₂e in 2018 and increase to \$50 per tonne CO₂e in 2022.

BRITISH COLUMBIA CARBON TAX

Cap and trade legislation

British Columbia has introduced legislation authorizing hard limits (caps) on greenhouse gas (GHG) emissions through the *Greenhouse Gas Reduction (Cap and Trade) Act*. This legislation enables British Columbia to participate in the trading system that is being developed with other jurisdictions through the Western Climate Initiative. Through the *British Columbia Reporting Regulation*, which falls under the Act, reporting operations outside the public sector that emit more than 10,000 tonnes of carbon dioxide-equivalent (CO₂e) are required to report annually. The *British Columbia Reporting Regulation* also requires any British Columbia business facility that emits 25,000 tonnes or more of

CO₂e per year to complete a third-party audit of its annual emissions report. The British Columbia Ministry of Environment estimates that 160 to 200 British Columbia facilities are required to file reports, and 80 to 100 of those are required to have third-party audits. Many of the latter are companies with oil and gas operations in British Columbia (i.e., the requirement to file is based on the location of the actual operations and not the location of head office). Currently the information is used as an inventory of emissions; however, if cap and trade is implemented, the reported emissions for each sector and operation will be used to drive the cap and trade process.

Carbon tax

British Columbia levies a carbon tax – a tax based on GHG emissions generated from burning fossil fuels. Carbon tax applies to the purchase or use of fossil fuels within British Columbia, including gasoline, diesel fuel, natural gas, home heating fuel, propane, coal, pentanes, and gas liquids. The tax also applies to tires and peat used as fuel.

Carbon tax applies in addition to the tax payable in respect of motive fuels taxed under the British Columbia *Motor Fuel Tax Act*. The carbon tax rate is of \$30 per tonne. Table 7 shows the tax rates that apply for the principal fuel types as at July 1, 2014.

All consumers and businesses purchasing fossil fuels in British Columbia are subject to the tax, with certain exceptions – for example, fuel purchased for air or marine travel out of British Columbia, and fuel purchased as feedstock to produce other products.

The new BC government has reinforced the province's commitment to reduce its carbon tax emissions. It announced that it will raise the carbon tax rate by \$20 a tonne in annual \$5 increments starting in April 2018.

BC also announced in October 2017 the creation of a Climate Solutions and Clean Growth Advisory Council to meet its emissions reduction targets by expanding the base to other sectors such as natural gas, transportation, forestry and agriculture industries and utilities, and public sectors.

For fuels other than natural gas, collection and remittance procedures for the carbon tax are similar to those under the *Motor Fuel Tax Act*, with fuel sellers being required to pay security equal to the tax payable on the final retail sale and consumers being ultimately liable to pay the tax. For natural gas, the tax is collected at the time of sale to a person intending to consume or use the gas in British Columbia.

Table 7: Carbon tax rates, British Columbia, as of November 2017

Type of fuel	Rate as at November 2017
Gasoline	6.67 cents per litre
Diesel fuel	7.67 cents per litre
Natural gas	5.70 cents per cubic meter
Propane	4.62 cents per litre
Coal – low heat value	\$53.31 per tonne
Coal – high heat value	\$62.31 per tonne

ALBERTA CARBON TAX

The Alberta government announced an economy wide carbon pricing back in November 2015. Under the new plan, Alberta has a hybrid carbon pricing approach that consists of an output-based pricing system and a carbon levy.

Output-based pricing system

Starting in 2018, the Carbon Competitiveness Regulation (“CCR”) is replacing the Specified Gas Emitters Regulation (“SGER”) that was in place since 2017.

Under the SGER regime, facilities are required to become more efficient over time as compared to their respective baseline emission intensities. In this respect, facilities that emit over the baseline level are required to take compliance actions and those facilities that are able to reduce their emission intensities below the target can generate emission performance credits that are tradable or can be saved for use in future years.

CCR is a product-based, emissions performance standard. Under the CCR, facilities will not be compared to their baseline GHG emissions. Rather, they will be compared to GHG emissions intensities from other similar facilities. Facilities that emit more than 100,000 tonnes of CO₂ per year will be allocated emissions permits each year these facilities include:

- Electricity production
- Heat production and usage
- Hydrogen
- In-situ Bitumen Extraction
- Oil Sands Mining and Extraction
- Refining

- Landfills
- Pulp and paper
- Food processing

The allocation will be based on benchmarks from high performing industry peers or “best-in-class” operators who produce similar products. Under this framework, facilities that emit more GHG emissions in their respective sectors will be required to take compliance actions to become more efficient. Facilities that emit at least 1 megaton of CO₂ per year will have to report and submit their compliance quarterly. They will also have to communicate their anticipated emission production on an annual basis.

Like the SGER, facilities under the CCR can meet their obligations by purchasing and using CCR emissions performance credits or offsets, or contributing to the Climate Change and Emissions Management Fund. However, while the SGER allows for the unlimited use of the emission performance credits and offsets, the CCR regime is expected to limit their use at a certain level to be determined in the regulations.

Many programs such as the renewable energy program, the oil sands emission cap, and the electricity transition will not be governed by the CCR but will be subject to different processes.

Carbon levy

On January 1, 2017 Alberta introduced a broad based carbon levy on fuel. The levy was introduced at a rate of \$20/tonne in 2017 and is set to increase to \$30/tonne on January 1, 2018. The carbon levy is included in the price of all fuels that emit GHG when combusted, such as diesel, gasoline, natural gas and propane.

The consideration payable is subject to the GST. Rebates are provided to offset the costs of the carbon levy.

Some exemptions are available such as:

- Fuels used in the operations of an SGER person
- Fuel used in a production process before 2023
- Fuels flared or vented in conventional oil and gas before 2023
- Fuels used in industrial processes or as raw materials to create another fuel or product
- Marked fuel purchased by farmers in their farming operations
- Inter-jurisdictional air flights
- Fuel purchased by a person with an exemption certificate or a license

Table 8: Carbon levy rates, Alberta

Type of fuel	January 1, 2017 rate (\$20/ton)	January 1, 2018 rate (\$30/ton)
Diesel	5.35 ¢/L	8.03 ¢/L
Gasoline	4.49 ¢/L	6.73 ¢/L
High Heat Value Coal	\$44.37 /ton	\$66.56 /ton
Low Heat Value Coal	\$35.39 /ton	\$53.09 /ton
Natural Gas	\$1.011 /GJ	\$1.517 /GJ
Non-Marketable or Raw Gas	\$1.150 /GJ	\$1.720 /GJ
Propane	3.08 ¢/L	4.62 ¢/L

Glossary

Abbreviations

ACFRE	Adjusted cumulative foreign resource expense
ASPA	Adjusted stub period accrual
CBM	Coalbed methane
CCA	Capital cost allowance
CCDE	Cumulative Canadian development expense
CCEE	Cumulative Canadian exploration expense
CCOGPE	Cumulative Canadian oil and gas property expense
CCPC	Canadian-controlled private corporations
CDE	Canadian development expense
CEC	Cumulative eligible capital
CEDOE	Canadian exploration and development overhead expense
CEE	Canadian exploration expense
CFRE	Cumulative foreign resource expense
COGPE	Canadian oil and gas property expense
CRA	Canada Revenue Agency
CRIC	Corporation resident in Canada
CTCA	Cumulative tax credit account
ERCB	Energy Resources Conservation Board
FAPI	Foreign accrual property income
FEDE	Foreign exploration and development expense
FRE	Foreign resource expense
GAAP	Generally accepted accounting principles
GAAR	General anti-avoidance rule
GHG	Greenhouse gas

GST	Goods and services tax
HST	Harmonized sales tax
IFRS	International financial reporting standards
ITA	<i>Income Tax Act</i> , RSC 1985, c. 1 (5th Supp.), as amended
ITC	Investment tax credit
LCT	Large corporations tax
LFE	Large final emitters
LNG	Liquefied Natural Gas
MFN	Most favoured nation
NPI	Net profits interest
PFIC	Passive foreign investment company (US)
PLOI	Pertinent loan or indebtedness
PST	Provincial sales tax
QET	Qualifying environmental trust
QRE	Qualified resource expense
QST	Quebec sales tax
R&D	Research and development
SC	Successor corporation
SGER	Specified gas emitters regulation
SIFT	Specified investment flow-through
SR&ED	Scientific research and experimental development
TIEA	Tax information exchange agreement
UCC	Undepreciated capital cost
WEARR	Well event average royalty rate

Tax terms

Acquisition of control	Transaction where one corporation acquires control of another corporation under the ITA.
Active business income	In the context of the foreign affiliate rules, active business income includes income earned from any business (other than an investment business or a non-qualifying active business) and certain income from property such as interest, royalties, and rent that is deemed by the foreign affiliate rules to be active business income.
Adjusted cost base	The cost of acquisition of a capital property as adjusted by the ITA.
Adjusted cumulative foreign resource expense (ACFRE)	Consists of cumulative foreign resource expenses as adjusted to take into account a transaction subject to the successor corporation rules.
Adjusted stub period accrual (ASPA)	See discussion on page 34.
“All or substantially all”	The ITA does not define the term “all or substantially all.” The CRA takes the position that all or substantially all means 90 percent but does not provide a methodology to use in the calculation of all or substantially all. The limited jurisprudence available does not provide much guidance.
Allowable capital loss	One-half of a capital loss.
Amalgamation	A merger of two or more corporations to form one corporate entity. See the discussion at page 20.
Arm’s length	While not precisely defined in the ITA, two parties are considered <i>not</i> to be dealing at arm’s length if they are considered related persons as defined in section 251 of the ITA.
Base Erosion and Profit Shifting (“BEPS”)	An initiative headed by the Organization for Economic Cooperation and Development (“OECD”), BEPS is an attempt supported by the world’s major economies to try to address the widespread perception that corporations don’t pay their fair share of taxes.
Branch	Local offices of foreign companies that allow these companies to carry on business as well as administrative duties within the local context without incorporating in a local jurisdiction.
Canadian-controlled private corporation (CCPC)	A private corporation that is a Canadian corporation and that is not controlled by one or more non-residents of Canada, one or more public corporations, or any combination of them.
Canadian corporation	A corporation incorporated in any jurisdiction in Canada or resident in Canada.
Canadian development expense (CDE)	See discussion on page 15.
Canadian exploration expense (CEE)	See discussion on page 15.
Canadian oil and gas property expense (COGPE)	See discussion on page 17.
Canadian partnership	At any time is a partnership all of the members of which are resident in Canada at that time.
Canadian resource property	An oil and gas property or a mining property in Canada.

Capital cost allowance	The amount allowed to be deducted from income to account for the depreciation of capital property. The amount of capital cost allowance available for a property in a year will depend on its cost and what type of property it is. The Regulations contain a detailed categorization of types of property and the rates at which they can be depreciated.
Capital gain	A capital gain from a disposition of capital property is the amount by which the proceeds of disposition exceed the adjusted cost base and any reasonable costs of disposition.
Capital loss	A capital loss from a disposition of capital property is the amount by which the adjusted cost base and any reasonable costs of disposition exceed the proceeds of disposition.
Capital property	Capital property is property that, when disposed of, will give rise to a capital gain or a capital loss, rather than a gain or loss recognized on account of income. Property is capital property if the taxpayer acquires it to produce income rather than to resell it for a profit. Thus, inventory is not capital property, but each of land (other than a resource property) and machinery used in the oil and gas development process is capital property.
Capital tax	A tax on the capital of a corporation. For these purposes, the capital of a corporation consists of its equity and debt less an investment allowance for its interests in the equity and debt of other corporations.
Control	There are two types of control of a corporation recognized by the ITA: de jure control and de facto control. De jure control contemplates the right of control that rests in ownership of such a number of shares as carries with it the right to a majority of the votes in the election of the board of directors. De facto control contemplates control of a corporation, directly or indirectly in any manner whatever, as a matter of fact by the exertion of influence on the business and affairs of the corporation. For the purposes of the acquisition-of-control rules in the ITA, an acquisition of control of a corporation occurs where a person acquires de jure control of the corporation.
Controlled foreign affiliate	A foreign affiliate is a controlled foreign affiliate if a Canadian resident owns more than 50 percent of the voting shares of the foreign affiliate, or would own more than 50 percent of the voting shares if it held all of the shares owned by related persons and up to four arm's length Canadian residents and persons related to them.
Cumulative Canadian development expense (CCDE)	See discussion on page 16.
Cumulative Canadian exploration expense (CCEE)	See discussion on page 16.
Cumulative Canadian oil and gas property expense (CCOGPE)	See discussion on page 17.

Cumulative eligible capital (CEC)	Three-quarters of the cost of eligible capital property is added to cumulative eligible capital and three-quarters of the proceeds of disposition of eligible capital property is deducted from cumulative eligible capital. A taxpayer may claim a deduction of 7 percent on a declining balance basis of its cumulative eligible capital.
Cumulative foreign resource expense	See discussion on page 17.
Depreciable property	Capital property whose cost can be deducted from income over time. The amount that can be deducted in a year is limited to the capital cost allowance for the particular class of property.
Eligible oil sands mine development expenses	Expenses incurred, after March 21, 2011 and before 2015, to bring an oil sands mine into production. A portion of such expenses qualifies as CEE.
Eligible capital expenditure	The cost of eligible capital property.
Eligible capital property	Consists of intangible capital property such as goodwill, franchises, incorporation fees, and customer lists.
Eligible property	Property that is eligible to be transferred to a corporation on a tax-deferred basis under section 85 of the ITA.
Excluded property	Property whose disposition by a foreign affiliate of a Canadian resident does not result in foreign accrual property income.
Exempt surplus	See discussion on page 41.
Farm-in/farm-out	See discussion on page 37 and following.

Farmee	A person who acquires an interest in a resource property of another person (the farmor) in consideration for funding or performing exploration and development work on the property.
Farmor	A person that has an interest in a resource property and grants an interest in that resource property to another person (the farmee) in consideration for the farmee's either funding or performing exploration and development work on the property.
Flow-through share	A share or a right to acquire a share of a principal-business corporation issued by the corporation to an investor pursuant to an agreement in writing under which the corporation agrees to incur qualifying CEE or qualifying CDE and to renounce such expenses to the investor.
Foreign accrual property income (FAPI)	Income of a controlled foreign affiliate of a Canadian resident that is imputed to the Canadian-resident as it is earned. Includes most passive property income such as interest, rent, royalties, and taxable capital gains realized by the controlled foreign affiliate on dispositions of property other than excluded property.
Foreign affiliate	A non-resident corporation will be a "foreign affiliate" of a Canadian-resident taxpayer if the Canadian resident owns directly or indirectly 1 percent or more of the shares (of any class) of the non-resident, and, either alone or together with related persons, 10 percent or more of the shares (of any class) of the non-resident.
Foreign exploration and development expense (FEDE)	An expense that would be a foreign resource expense if it were incurred after 2000.

Foreign resource expense (FRE)	See discussion on page 17 and following.
Foreign resource property	Property that would be a Canadian resource property if it were located in Canada.
Functional currency	See discussion on page 14.
Functional currency year	A taxation year in which a functional currency election is effective.
Generally accepted accounting principles (GAAP) and international financial reporting standards (IFRS)	Accounting standards accepted by a recognized professional body.
General anti-avoidance rule (GAAR)	A statutory rule in the ITA that applies to deny a tax benefit arising from an avoidance transaction if the transaction otherwise would result in a misuse or abuse of the provisions of the statute. An avoidance transaction is a transaction, or a transaction that is part of a series of transactions, that cannot reasonably be considered to have been undertaken or arranged primarily for bona fide purposes other than to obtain the tax benefit.
Hybrid surplus	See discussion on page 41.
Inter-vivos trust	A trust that takes effect during the lifetime of its creator.
Investment business	See discussion on page 42 and following.
Investment tax credit	A deduction from tax payable earned by incurring qualifying expenses such as pre-production oil and gas expenditures and scientific research and experimental development expenses (SR&ED).
Joint venture	An undertaking carried out by two or more persons pursuant to which assets of the business are owned directly by the participants in the joint venture.

Large corporations tax	A federal capital tax that was previously imposed under Part I.3 of the ITA.
Limited partnership	A partnership in which one or more partners is a general partner that manages the business of the partnership and has unlimited liability for the debts of the partnership, and one or more partners is a limited partner that does not manage the business of the partnership and has limited liability for the debts of the partnership.
Net capital losses	The difference between allowable capital losses and taxable capital gains realized on the disposition of capital properties.
Non-capital losses	Net operating losses from a business or a property (i.e., losses other than net capital losses).
Non-depreciable capital property	Capital property for which a deduction for capital cost allowance is not permitted; includes land (other than a resource property), shares, and partnership interests held as an investment to produce income.
Non-portfolio property	Includes Canadian resource properties, Canadian real property, and shares or securities of another entity that have a value in excess of 10 percent of the value of the subject entity.
Non-qualifying active business income	Active business income earned in a non-treaty or non-TIEA country.
Oil and gas property	Includes any right, license, or privilege to take petroleum, natural gas, or related hydrocarbons; rental or royalty interests in an oil or gas well; and any land that derives its principal value from its petroleum or natural gas content.
Oil and gas well	Any well drilled for the purpose of producing petroleum or natural gas, or for the purpose of determining the existence, location, extent, or quality of a natural accumulation of petroleum or natural gas; excludes bituminous sands or oil shale.

Original owner	The person who incurred resource expenses that a successor may deduct in accordance with the successor corporation rules.
Participating interest/ Participating debt interest	Interest that is paid or payable dependent on the success of the payer's business or investments.
Partnership	A business carried on in common with a view to profit by the partners of the partnership.
Person	An individual, a trust, or a corporation. A partnership is not a person for the purposes of the ITA except where expressly provided. A joint venture is not a person for tax purposes.
Pre-acquisition surplus	See discussion on page 41.
Predecessor owner	A person who acquires properties from an original owner and transfers them to a successor in accordance with the successor corporation rules.
Principal-business corporation	A corporation whose principal business includes: <ul style="list-style-type: none"> – mining or exploring for minerals; – processing mineral ores for the purposes of recovering metals therefrom; – the production, refining or marketing of petroleum, petroleum products or natural gas; or – exploring or drilling for petroleum or natural gas; and – all or substantially all of the assets of which are shares of the capital stock or indebtedness of one or more other corporations that are related to the corporation and whose principal business is described in the foregoing items. <p>– A principal-business corporation may be a Canadian corporation or a foreign corporation.</p>

Qualifying CEE/ Qualifying CDE	Canadian exploration expense and Canadian development expense that may be renounced in accordance with the flow-through share rules.
Qualifying environmental trust (QET)	See discussion on page 27 and following.
Qualified resource expense (QRE)	See discussion on page 35.
Regulations	The Income Tax Regulations (Canada) promulgated under the ITA.
Resource deduction or resource expense	Canadian development expense, Canadian exploration expense, Canadian oil and gas property expense, foreign exploration and development expense, or foreign resource expense.
Resource property	A mining property or an oil and gas property.
Resource surcharge	A capital tax imposed by Saskatchewan on large resource companies and resource trusts; equal to 1.8 percent or 3 percent, depending on certain conditions, of the value of sales of potash, uranium, and coal produced in Saskatchewan.
Scientific research and experimental development (SRED)	See discussion on page 26.
Specified investment flow-through (SIFT) entity	A specified flow-through partnership or trust resident in Canada the units of which have a public market and which holds property that constitutes non-portfolio property.
SIFT legislation	Legislation that imposes a tax on income from a business carried on in Canada by a SIFT entity.

Specified amount	The amount of the loan from a non-resident to a taxpayer that is required to be included in income if it is not repaid within two years.
Specified debtor	A person with which the taxpayer does not deal at arm's length.
Specified oil sands mine development expenses	Expenses incurred, after March 21, 2011 and prior to 2015, in bringing an oil sands mine into production; a form of CEE.
Specified non-resident shareholder	A specified shareholder of a corporation who is, at that particular time, a non-resident person.
Specified shareholder	A shareholder in a corporation who owns, directly or indirectly, at any time of the year, 10 percent or more of the issued shares of any class of the capital stock of the corporation or any corporation that is related to it.
Stub period	See discussion on page 34.
Successor	See discussion on page 18 and following.
Surplus rules	See discussion on page 40 and following.
Tax-free surplus balance	See discussion on pages 32 and 47.
Taxable Canadian property	Canadian property that includes real estate located in Canada, Canadian resource property, timber resource property, or an income interest in a trust and a life insurance policy in Canada; does not include shares of corporation (and partnership interests and interests) that did not, at any time during the previous 60 months, derive their value principally from real or immovable property in Canada, Canadian resource property, or timber resource property.

Taxable capital gain	One-half of a capital gain.
Taxable surplus	See discussion on page 41.
Tax information exchange agreement (TIEA)	A bilateral agreement entered into by two countries to exchange information for tax purposes.
Testamentary trust	A trust that takes effect on the death of its creator.
Undepreciated capital cost	The portion of the cost of a depreciable property of a particular class prescribed by the Regulations that has not been deducted from income in previous years. Calculated as the cost of the property less the capital cost allowance claimed for that class of property in previous years.
Working interest	The right that a person receives from the owner of the resource to drill or take petroleum, natural gas, or related hydrocarbons. Frequently the Crown is the owner of the resource but in the case of freehold rights, the working interest holder will be someone to whom the Crown has granted the resources.



Oil and gas terms

Battery	The facility in which oil, gas, and water are separated and stored.
Bitumen	A viscous mixture of hydrocarbons obtained naturally or as a residue from petroleum distillation; used for road surfacing and roofing and capable of being upgraded to synthetic crude oil.
Casing	A large pipe assembled and inserted into a recently drilled section of a borehole and typically held in place with cement.
Coalbed methane (CBM)	A form of natural gas extracted from coal beds.
Coal gas	A mixture of gases obtained by the destructive distillation of coal and formerly used for lighting and heating.
Completion	The process of making a well ready for production; excludes the drilling process.
Completion rig	Machinery that is capable of pulling pipe or tubing in and out of a well.
Compressor	A mechanical device that increases the pressure of natural gas within a pipeline by reducing its volume.
Conservation gas	Gas that is produced in association with oil, and is conserved and marketed, rather than flared into the atmosphere.
Conventional/unconventional oil and gas deposits	Conventional oil and gas deposits can be extracted, after the drilling operations, just by the natural pressure of the wells and pumping or compression operations. Unconventional oil and gas deposits exist in less accessible types of rock and require special extraction methods.

Crown royalties	Compensation made to the government by businesses using Crown lands for the purpose of producing oil and gas; generally expressed in terms of payment for each unit produced.
Decommissioning	A regulatory requirement that an oil and gas producer restore to its original state the surface of land where drilling and producing was done.
Downhole pumps	A pump with a hermetically sealed motor that allows it to operate inside a well and thereby increases the well's production.
Drilling	The process of boring a hole into the ground to access petroleum and other hydrocarbon reserves trapped within the earth.
Exploratory probe	A kind of probe, not included in the definition of an oil or gas well and not defined in the ITA, that is used in the oil and gas industry to understand reserve aspects.
Fractionation plants	A plant in which mixtures of light hydrocarbons are separated into individual, or industrially pure, substances.
Fracturing	Well-stimulation technique in which rock is fractured by a hydraulically pressurized liquid to allow production of oil or gas that would otherwise be trapped in certain rock formations.
Freehold rights/royalties	Compensation made to the landowner by the oil and gas producer for the use of the land to produce oil and gas; generally expressed as a percentage payment for each unit produced.
Freehold lease rentals	Rental payment made by the oil and gas producer to the landowner for the right to access the surface land.

G3 expenses	CEE consisting of geological, geophysical, or geochemical expenses incurred for the purpose of determining the existence, location, extent, or quality of oil or gas in Canada (see the discussion at page 15).
Gas	Any combustible fluid used as fuel.
Gathering systems (or lines)	A pipeline, or system of pipelines, that transports gas from the point of production to a transmission line or main.
Gross overriding royalty (GORR)	A fractional, undivided interest in an oil and gas property with the right to participate or receive proceeds from the sale of said property's production. The interest lies in the proceeds or revenue from the oil and gas, not in the minerals themselves. Generally, GORRs are bound to the term limits of the existing mineral lease, and dissolve with the lease.
Horizontal drilling	The practice of drilling non-vertical wells; also known as directional drilling.
Land – subsurface rights	Rights that confer on the holder the right to exploit an area for minerals it harbors; also known as mineral rights.
Lease bonus	Consideration that is paid by the lessee for the right to drill, explore, or take oil and gas from the landowner.
Liquefied Natural Gas	Natural gas that has been converted to liquid form for ease of storage or transport.
Mineral	A substance, which may or may not be of economic value, that occurs naturally in the earth. It is homogeneous, has a certain chemical composition, and appears in crystal or grain form.

Net profits interest (NPI)	A royalty that is based on the net profit from the a resource property or properties.
Non-conservation gas	All gas that is not classified as conservation gas (including gas produced in association with oil that is part of a concurrent production scheme).
Oil	A viscous liquid derived from petroleum, especially for use as a fuel or lubricant.
Oil sands	A deposit of loose sand or partially consolidated sandstone containing petroleum or other hydrocarbons.
Pipeline	A linear sequence of specialized pipe used for transporting oil, gas, or related hydrocarbons.
Production tubing	A tube used in a wellbore through which production fluids travel. Production tubing is run into the drilled well after the casing is run and cemented in place.
Proven reserves/ Proven resource property	Proven reserves for an oil and gas resource property are the estimated quantities of petroleum and natural gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in the future under existing economic and operating conditions.
Pumpjack	An above ground drive used to mechanically lift liquids out of an oil well if there is not enough bottom hole pressure for the liquid to flow all the way to the surface.
Refinery	An industrial plant where oil is processed and refined into more useful products.
Seismic exploration	A type of geophysical exploration that uses seismic waves to detect potential drilling opportunities.

Separation	Separating products produced from oil and gas wells into gaseous and liquid components.
Separator	A pressure vessel used to separate well fluids produced from oil and gas wells into gaseous and liquid components.
Shale gas	Natural gas occurring within or extracted from shale rock.
Steam Assisted Gravity Drainage (SAGD)	A drilling technique that is used to extract heavy oil that is too deep or otherwise economically inefficient to mine by traditional methods.
Straddle plants	Extraction plants located near or on a gas transmission line. The natural gas liquids are extracted from the natural gas before re-injecting the natural gas into the pipeline.
Surface lease rentals	The payment required to acquire the right to access the surface land in order to drill.
Surface rights	The right to access certain lands in order to drill and gain access to the petroleum or hydrocarbon deposit therein.
Tailings	The finely ground residue or waste materials rejected from a mill after most of the recoverable minerals have been extracted.
Tailings pond	A containment area for refused tailings, where the solid particles are separated from the water.
Tangible/intangible assets	Generally, any mineral right, license or privilege, including casing, are considered an intangible property. A tangible asset is one that is moveable between well-sites above the ground.

Tubing	Metal piping, normally 1 to 3.25 inches in diameter, inserted in the well to permit the production of oil or natural gas. This is sometime referred as production tubing and fits within the casing.
Unproven resource property	A resource property for which proven reserves have not been attributed.
Vapour extraction (Vapex)	An oil and gas extraction technique that uses hydrocarbon solvents injected into an upper well to dilute bitumen and enables the diluted bitumen to flow into a lower well.
Wellhead	The component at the surface of an oil or gas well that provides the structural and pressure-containing interface for the drilling and production equipment.



Appendix

Contact numbers and websites for various relevant federal and provincial government organizations

▶ Alberta Tax and Revenue Administration 780-427-3044 finance.alberta.ca/publications/tax_rebates/index.html	▶ New Brunswick Department of Finance 506-453-2451 gnb.ca	▶ Prince Edward Island Department of Finance and Municipal Affairs 902-368-4000 gov.pe.ca/finance
▶ British Columbia Ministry of Finance 877-388-4440 gov.bc.ca/fin	▶ Northwest Territories 867-873-7117 fin.gov.nt.ca	▶ Revenu Québec 800-567-4692 revenuQuebec.ca/en
▶ Canada Revenue Agency 800-267-6999 cra-arc.gc.ca	▶ Nova Scotia Finance 902-424-5554 gov.ns.ca/finance/en	▶ Saskatchewan Ministry of Finance 306-787-6768 finance.gov.sk.ca
▶ Manitoba Finance 204-945-5603 gov.mb.ca/finance	▶ Nunavut 867-975-5800 gov.nu.ca/finance	▶ Yukon 867-667-5811 finance.gov.yk.ca
▶ Newfoundland and Labrador Department of Finance 709-729-6165 fin.gov.nl.ca/fin	▶ Ontario Ministry of Finance 866-668-8297 fin.gov.on.ca/en	

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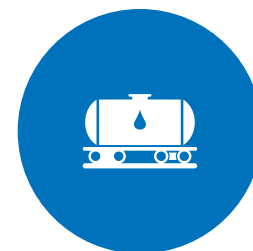
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KPMG's energy tax practice

If you require more information on the matters discussed in this publication, please call your KPMG Oil and Gas Tax Adviser. We welcome the opportunity to meet with you to discuss how we can best assist you.

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