

Canada 

International energy data and analysis

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[full report](#)

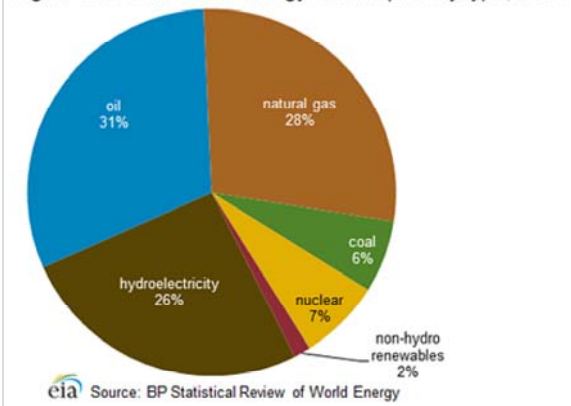
Overview

Canada is one of the world's five largest energy producers and is the principal source of U.S. energy imports.

Canada is a net exporter of most energy commodities and a significant producer of crude oil and other liquids from oil sands, natural gas, and hydroelectricity. Energy exports to the United States account for the vast majority of Canada's total energy exports. However, because of economic and other considerations, Canada is developing ways to diversify its trading partners, especially by expanding ties with emerging markets in Asia.

Canada is endowed with abundant and varied natural resources, ranking fifth in 2014 among the largest energy producers in the world, trailing only [China](#), the United States, [Russia](#), and [Saudi Arabia](#). Relatively energy intensive compared to other industrialized countries, Canada's economy is fueled largely by petroleum, natural gas, and hydroelectricity (Figure

Figure 1. Canada's total energy consumption by type, 2014 ¹⁾.

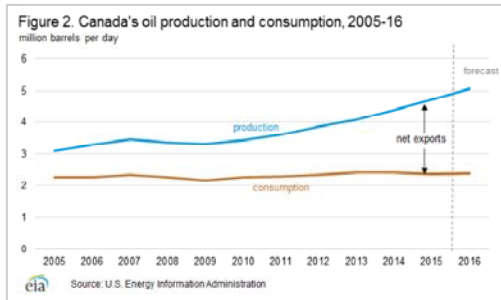


Crude oil and other liquids

Canada's oil sands are a significant contributor to the recent and expected future growth in the world's liquid fuel supply, and comprise most of the country's proved oil reserves, which rank third globally.

Overview

In 2014, Canada was the world's fifth-largest crude oil and other liquids producer and a net exporter of oil (Figure 2). Virtually all of its crude oil exports are destined for the United States, because Canada lacks sufficient export capacity to send its liquids elsewhere. Canada is a major producer of crude oil. The recent growth in its liquid fuels production has been driven by bitumen and upgraded synthetic crude oil produced from the oil sands of Alberta. Most of Canada's proved oil reserves and the expected future growth in the country's liquid fuels production will be derived from these resources.



Reserves

According to the *Oil & Gas Journal*, Canada had roughly 173 billion barrels of proved oil reserves at the beginning of 2015, ranking it third in the world. Only Saudi Arabia and Venezuela hold higher reserves. In addition, Canada is one of only two countries among the top 10 proved reserves holders that is not a member of the Organization of the Petroleum Exporting Countries (OPEC).

Canada's proved oil reserves from 1980 to 2002 were well below 10 billion barrels. In 2003, they rose to 180 billion barrels after oil sands resources were deemed to be technically and economically recoverable. Oil sands now account for approximately 166 billion barrels of proved reserves,¹ nearly all of Canada's current proved oil reserves. Oil sands proved reserves saw a slight year-on-year decline in 2014. Nevertheless, oil sands production during the year continued to be robust, despite the decline in crude oil prices.

Sector organization

Canada has a privatized oil sector that includes participation by many domestic and international oil companies. Many Canadian oil firms underwent strategic corporate restructuring, including consolidation, in the wake of the recent economic downturn. The technically sophisticated production processes required in the development of Canada's oil sands resources promote regional and functional specialization by independents and major oil companies.

Many Canadian firms participate in upstream oil and natural gas ventures, from large-scale active or planned commercial projects to smaller pilot projects that serve as test beds for new technologies. The largest Canadian energy companies with a presence in the domestic upstream and downstream sectors include Suncor (which acquired Petro-Canada in 2009), Syncrude, Canadian Natural Resources Limited, Imperial Oil, Cenovus (which was spun off from Encana), and Husky Energy. Other Canadian companies, particularly Enbridge and TransCanada, dominate midstream pipeline infrastructure.

The participation of international oil companies (IOCs), along with some national oil companies (NOCs) in Canada's oil sector has risen rapidly. Aside from economic and political motivations, investments in oil sands enable foreign companies to gain technological expertise that can be applied to unconventional resources elsewhere. While the Investment Canada Act stipulates that any large investment in Canada must be of net benefit to Canada, indicating possible limits on foreign control of strategic commodities, actual limits have been infrequent. U.S. companies involved in Canada's upstream and/or downstream oil industry include Chevron, ConocoPhillips, Devon Energy, and ExxonMobil. BP, Shell, Statoil, and

Total are among the other major IOCs² with producing or planned projects in the Canadian oil sands.

Chinese companies, including PetroChina, China National Petroleum Corporation (CNPC), China National Offshore Oil Corporation (CNOOC), and Sinopec, have invested heavily in the oil sands and other parts of Canada's energy sector. PetroChina owned a 60% interest in the MacKay River and Dover projects, and increased its MacKay River stake to 100% in January 2012. In 2010, Sinopec acquired ConocoPhillips' stake in Syncrude Canada. With its \$15 billion acquisition of Nexen, CNOOC became the first Chinese company to operate a commercial-scale oil sands operation.³

Federal and provincial bodies coordinate policy and regulation in Canada. Provincial authorities, the largest and most influential of which is the Alberta Energy Resources Conservation Board (ERCB), handle most sector oversight. Canada's national regulatory body is the National Energy Board (NEB).

Exploration and production

Canada produced about 4.4 million barrels per day (b/d) of petroleum and other liquid fuels in 2014, an increase of more than 300,000 b/d over the previous year. Canada's production is on track to increase again in 2015, despite decreases in crude oil prices that have curtailed investment.

Oil production in Canada comes from three principal sources: the oil sands, the resources in the broader Western Canada Sedimentary Basin (WCSB), and the offshore oil fields in the Atlantic Ocean.⁴ Production from the oil sands accounted for more than half of Canadian crude oil and other liquids output in 2014, a proportion that has steadily increased over the past decade. The province of Alberta accounted for 78% of Canadian oil production in 2014. About 81% of Alberta's total crude oil production came from oil sands.⁵ Other noteworthy producing provinces are Saskatchewan, with roughly 15% of national output from its share of the WCSB, and areas off the east coast of Canada, primarily offshore Newfoundland and Labrador.⁶ Because production from offshore reserves comes from mature oilfields with typically declining production rates, western provinces are expected to comprise an increasing proportion of overall Canadian crude oil and other liquids production.⁷

Canada is expected to continue to be one of the largest sources of growth in non-OPEC liquid fuel supply. EIA's *Short-Term Energy Outlook* forecasts that Canada's liquids production will grow by 60,000 b/d in 2015 and an additional 90,000 b/d in 2016. While most of the increase will come from oil sands production, continued robust growth in natural gas production will generate increased output of natural gas liquids.

Oil sands

Oil sands are a form of petroleum in a semi-solid state that is typically found blended with sand, clay, and water in its natural state. The existence of oil sands has been known for centuries, but commercial mining operation did not begin until 1967. It was not until the early 2000s, however, that the right combination of innovation and price spurred the growth in oil sands production.

Nearly all of Canada's proved oil reserves are located in Alberta, 97% of which are in the form of oil sands, according to Alberta's provincial government.⁸ Alberta is also Canada's most prolific oil-producing region, where the surge in oil sands production has boosted total Canadian output to fifth globally. Within Alberta, there are three major oil sands deposits, the largest of which is the Athabasca deposit, followed by Cold Lake and Peace River.

Two methods of extraction are used predominantly in the oil sands: traditional pit mining on the surface and in-situ drilling underground. When mined at the surface, bitumen-rich earth is shoveled into trucks for separation at a processing facility. Surface mining has historically been the largest source of production from the oil sands, but its share has declined in the past few years because approximately 80% of bitumen reserves are situated too deep underground to be accessible by surface mining. In-situ extraction injects steam into underground formations to soften the bitumen and then pump it to the surface through wells. Steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS) are the two leading in-situ extraction techniques. In 2014, about 58% of Canada's oil sands production occurred via the in-situ method.⁹

With experience and technological advances in producing hydrocarbons from oil sands, the cost of extraction falls. While previously more expensive than U.S. tight oil production, oil from oil sands in Alberta is now more competitive with U.S. tight oil production costs. Breakeven costs, which have been of particular interest in the wake of the oil price slide

since mid-2014, vary greatly for oil sands projects. Although some of the large projects, such as Kearl Phase 1, show breakeven costs below currently prevailing crude oil prices, many other new projects' breakeven prices indicate that these projects are uneconomic in the current price environment. According to Citibank's breakeven analysis of Canadian oil sands projects, new pit mining projects see breakeven oil prices jump to as high as \$95/barrel while in-situ new projects breakeven prices are above \$80/b.¹⁰ Existing oil sands projects are at a lower risk of shut-ins due to low oil prices. Oil sands projects by their nature have very long pay-back periods and their profitability is evaluated in decades' long terms. Although low oil prices can affect oil sands production, this is not likely to happen in large scale to projects already operating, despite the current low prices. Canadian oil sands operators may see upgraders taken out for maintenance and remaining out of service for extended periods of time, but a large-scale shutting in of projects is very unlikely.

Once extracted, bitumen is a heavy, viscous type of crude oil. To flow in a pipeline, the bitumen must be diluted with condensate or other light oils (upgraded) by complex processing units ("upgraders") into a light, sweet (low sulfur) synthetic crude oil (SCO).

The largest oil sands projects are surface mining operations, although there are a greater number of in-situ projects. There are more than a dozen notable current and planned oil sands operations:¹¹

- **Syncrude Canada** is a joint venture by leading oil sands operators in mining and upgrading operations in the projects of Mildred Lake and Aurora. Syncrude received regulatory approval for a roughly 200,000 b/d expansion in Aurora SouthTrain 1 and 2. Syncrude Canada's current production capacity is 350,000 b/d.
- **Suncor Energy's** oil sands production averaged approximately 420,000 b/d of upgraded bitumen and SCO in 2014.¹² This production level is significantly below the company's total production capacity of more than 850,000 b/d, spread among mining and upgrading projects in Alberta's Athabasca region. Suncor has announced a number of planned greenfield and brownfield expansions in Chard, Lewis, Meadow Creek, Voyageur South, and additional stages to its Firebag and MacKay River operations. Suncor, in a joint venture with Total, began to develop the Fort Hills mine (160,000 b/d), which is expected to begin production in 2017.
- **Shell Albian Sands** is the leading owner and operator of the Athabasca Oil Sands Project, which includes the Muskeg River mine (155,000 b/d), the Jackpine mine (100,000 b/d), and the Scotford upgrader (255,000 b/d). Shell has received regulatory approval for expansions to its Muskeg and Jackpine operations, although the company has not yet announced a start date. Meanwhile, plans for its Pierre River project (which would add 200,000 b/d of oil sands production capacity to the company's portfolio) have been canceled.
- **Canadian Natural Resources** has two sizeable oil sands projects currently in production as well as a number of large planned projects. Its Horizon Oil Sands is an integrated mining and upgrading facility that can produce up to 152,000 b/d of light, sweet SCO in its first phase. Horizon will undergo process improvements and expansions over the next few years, with two phases planned to come onstream in 2016 and 2017. In addition, its Primrose and Wolf Lake operation has an in-situ capacity of 120,000 b/d. The company also began first-phase of operations at the in-situ Kirby project in 2013, with planned expansions for 2017 and 2022. In the next 10 years, Canadian Natural Resources aspires to construct other medium-sized in-situ projects, including Birch Mountain (120,000 b/d), Gregoire Lake, (120,000 b/d), and Grouse (40,000 b/d).
- **Imperial Oil** operates one of the largest in-situ projects, Cold Lake, which has a current capacity of 180,000 b/d, having expanded in January 2015 following the commission of the steam injection facility at the Nabiye expansion. The company is also operating its Kearl project, a 220,000 b/d mining operation, with the most recent expansion of 110,000 b/d brought online in June 2015. Future debottlenecking, which has received regulatory approval, is expected to increase Kearl production capacity to 345,000 b/d.
- **Cenovus** operates two large in-situ projects, Foster Creek and Christina Lake. Foster Creek was the first commercial SAGD project and now produces approximately 150,000 b/d, with additional phases in various stages of development. Phase G, the next stage slated to start production, is expected to begin during the first half of 2016. Phase H, however, was postponed indefinitely in response to declining crude oil prices. Christina Lake operates at a capacity of 138,800 b/d with expansion up to 150,000 b/d. Cenovus has also announced additional in-situ projects at East

McMurray, Grand Rapids, Narrows Lake, Steepbank, Telephone Lake, and West Kirby.

- **Devon Canada** operates the in-situ Jackfish project, which includes three operational phases, each with a capacity of 35,000 b/d. The Pike project, which received regulatory approval, will have a total capacity of 105,000 b/d. The first phase of that project is expected to come online in 2019.
- **CNOOC**, with its Nexen acquisition, operates the Long Lake project. It includes a SAGD facility that is producing 92,000 b/d of bitumen, of which about 59,000 b/d of SCO will be produced from an upgrader that became operational in 2009. The next phase of Long Lake, Kinosis, has a planned capacity of 37,500 b/d.
- **ConocoPhillips** produces a total of 148,000 b/d at its Surmont in-situ project. Phase 2 of the SAGD project started in late May 2015, adding 118,000 b/d. Production is expected to ramp up through 2017. ConocoPhillips expects to have additional phases of Surmont online after 2020.
- **Husky Energy** operates the 30,000 b/d Tucker in-situ project north of Cold Lake along with the 60,000 b/d Sunrise Athabasca in-situ project. First production at Sunrise began in mid-March 2015, with additional phases approved, although the company has yet to announce anticipated start-up dates.
- **MEG Energy** operates 60,000 b/d of combined production from the first two phases of the Christina Lake in-situ project. A third phase, which has received regulatory approval, will add 150,000 b/d for a total project capacity of more than 200,000 b/d. MEG Energy's 120,000 b/d Surmont project is under regulatory review.
- **Brion Energy**, a subsidiary of PetroChina, purchased the Mackay River and 40% of Dover in-situ projects from Athabasca Oil Sands Corp. Currently, only Phase 1 of Mackay River has commenced production this year, with a capacity of 35,000 b/d. Once all phases are brought onstream, Mackay River is expected to produce 150,000 b/d.
- **Statoil's** presence in Canada's oil sands is focused on the Leismer in-situ project, currently operating at 10,000 b/d capacity; several phases and expansions are planned.
- **Sunshine Oil Sands** has announced three separate in-situ projects that it intends to bring online over the next decade at Legend Lake, Thickwood, and West Ells, with a combined future capacity of 290,000 b/d. To date, Sunshine has brought online the first phase of its West Ells SAGD project at 5,000 b/d.
- **Total** received regulatory approval for the 100,000 b/d Joslyn North mine, but the project has been put on hold because of costs and oil price declines. The company continues to participate in building its Fort Hills and Surmont projects.

Western Canada Sedimentary Basin

The traditional center of Canada's oil production has been the Western Canada Sedimentary Basin (WCSB), which stretches from British Columbia across Alberta and Saskatchewan to Manitoba and part of the Northwest Territories. The WCSB contains some of the world's most abundant supplies of oil and natural gas, and remains a significant source of conventional oil production, despite the fact that it was surpassed by output from oil sands in 2006.

The depletion rates of traditional oil production in the WCSB are expected to fall in the coming years, because enhanced recovery techniques are applied to old wells and new resource deposits. In particular, technological advances in and the combination of horizontal drilling and hydraulic fracturing has made tight oil production from shale formations an increasingly attractive alternative to traditional production.

The two most prolific tight oil plays in Canada are the Bakken, which stretches across southern Saskatchewan and Manitoba (as well as the northeast corner of Montana and North Dakota) and the Cardium formation in Alberta.¹³ The Bakken has been for a key component of the recent growth in U.S. crude oil production.

Offshore

Most offshore crude oil and other liquids production in Canada occurs in the Jeanne d'Arc Basin, off the eastern shore of Newfoundland and Labrador. Light crude oil production from offshore areas in eastern Canada averaged about 220,000 b/d in 2014, nearly 14% of Canada's total crude oil production.¹⁴ Most of Canada's offshore output comes from the

ExxonMobil-operated Hibernia field, which came online in 1997 and produced about 115,000 b/d in 2014.

Two other significant offshore fields are Terra Nova and White Rose. Terra Nova, operated by Suncor on behalf of a large consortium, accounted for nearly 46,000 b/d of production in 2014. Output at this field increased in 2014 compared with the prior year, although that level is still lower than production achieved in the past decade. Husky Energy operates White Rose, production from which was well below its historical levels, at about 54,000 b/d in 2014 (combined with the North Amethyst field production). So far in 2015, Terra Nova and White Rose have produced about 37,000 b/d and 33,000 b/d, respectively.¹⁵ In May 2010, Husky started production at the North Amethyst field, one of the White Rose satellites that could offset declines elsewhere and extend the field complex's production life.¹⁶

Canada's offshore exploration and production is confined by many regulatory and legal impediments. A 1972 moratorium restricts field development off the Pacific coast, where there are an estimated 9.8 billion barrels of recoverable resources.¹⁷ A federal review of offshore drilling has resulted in limited E&P activity in the Arctic, but oil companies such as Imperial Oil, ExxonMobil, BP, and Chevron have secured acreage in the Beaufort Sea.¹⁸ However, drilling in the high-cost Arctic areas of Canada likely will be postponed for years, as the much lower crude oil prices since mid-2014 and the ensuing cuts in capital expenditures among oil producers have resulted in more conservative outlooks for Arctic oil exploration and development.

Trade

Nearly all of Canada's oil exports were directed to the United States in 2014. Canada is the largest source of U.S. crude oil and refined products imports, accounting for about 37% in 2014. That year, the United States imported 3.4 million b/d of oil and petroleum products from Canada, of which 2.9 million b/d were crude oil, including diluents.

While overall U.S. imports of crude oil are declining, Canada is one of the few countries from which U.S. crude oil imports are increasing. Over the past decade, U.S. imports of crude oil and other liquids from Canada have increased 58%, while oil imports from the other major suppliers have decreased, displaced largely by increased domestic production. The United States' net crude oil imports from Canada averaged 2.9 million b/d in 2014. Due to legal restrictions, Canada is the only country to import U.S. crude oil. Imports averaged 331,000 b/d in 2014, more than doubling year-over-year. Canada's petroleum product imports from the United States were 478,000 b/d in 2014.

Nearly all of Canada's crude oil exports to the United States come from the western provinces,¹⁹ nearly 70% of which (1.9 million b/d) goes to the U.S. Midwest (Petroleum Administration for Defense District [PADD] 2). The U.S. Gulf Coast (PADD 3) imported 193,000 b/d of crude oil from Canada in 2014, accounting for only about 6% of its total imports. Although the Gulf Coast refineries are best suited to handle the heavier crudes coming from western Canada, the current pipeline infrastructure allows the Gulf Coast to import less than a tenth of the crude oil that is sent to the Midwest. The eastern Canadian provinces, which are more densely populated but have less oil production, import some of the energy products they consume from the United States, including crude oil.

Pipelines

Pipelines connect the centers of Canadian production with refining and export centers in the eastern provinces, western Canada, and especially the United States. Pembina, Plains Midstream, Spectra Energy, Access Pipeline, and Inter Pipeline operate some of the largest domestic pipeline systems in western Canada. Four companies operate the majority of the export pipelines: Enbridge, Kinder Morgan, Spectra, and TransCanada. In total, members of the Canadian Energy Pipeline Association transported 3.4 million b/d of crude oil and other liquids over approximately 25,000 miles of pipeline in 2014.²⁰ However, an increasing volume of oil is transported by rail because of infrastructure constraints in the midcontinent region.

Operational export pipelines

Enbridge operates the largest Canadian export oil pipeline network. The Enbridge Mainline system, composed of the Canadian Mainline and the U.S. Mainline (Lakehead) pipeline networks, transports roughly 2.2 million b/d of petroleum and other liquids from western Canada, Montana, and North Dakota to the U.S. Midwest and eastern Canada. The Lakehead system includes the Alberta Clipper pipelines connecting Hardisty, Alberta to Superior, Wisconsin at a capacity of 450,000 b/d, following an expansion that was completed in August 2014.²¹ The Southern Lights pipeline lays parallel to the Alberta Clipper, but it runs in the opposite direction to transport lighter hydrocarbons back to Alberta for use as a diluent

in transporting and processing bitumen.²² Along with its other smaller pipelines on both sides of the border, Enbridge's large pipeline systems transport 53% of the U.S.-bound oil exported from Canada.

Kinder Morgan operates the Trans Mountain Pipeline System, which is the only pipeline system that transports crude oil to the west coast of North America. The pipeline originates in Edmonton, Alberta and travels to various marketing and refining stations near Vancouver, British Columbia. Its capacity is rated at 300,000 b/d.²³

TransCanada has established a foothold in Canada's crude oil export market through its Keystone system. The 2,600 mile pipeline with a capacity of 590,000 b/d runs from Hardisty, Alberta to Manitoba and crosses the border to Steele City, Nebraska where it splits into two systems servicing the U.S. Midwest and U.S. Gulf Coast.²⁴

Spectra operates the Spectra Express pipeline, which runs from Hardisty, Alberta to Casper, Wyoming at a designed capacity of 280,000 b/d.²⁵

Proposed export pipelines

TransCanada has proposed Keystone XL as an addition to the Keystone system. The pipeline was supposed to travel directly from Hardisty, Alberta, to Steele City, Nebraska, with a capacity of 830,000 b/d.²⁶ Since the pipeline would cross an international border, a presidential permit needed be granted stating that the project is in the United States' national interest. In May 2012, TransCanada reapplied for a presidential permit after the Administration denied its initial application because of environmental concerns that had not been resolved as of the deadline for a decision. TransCanada's new application included alternative routes through Nebraska but was ultimately denied in November 2015. As an alternative to the Keystone XL pipeline, crude oil from Alberta will continue to be shipped by rail.²⁷

While Keystone XL was initially proposed as an integrated pipeline from Canada to the U.S. Gulf Coast, a shorter section that is entirely within the United States was pursued as a separate project when the presidential permit for the cross-border segment was not approved. The TransCanada pipeline that connects Cushing, Oklahoma with the Texas refining sector, now known as the Gulf Coast Pipeline Project, has helped resolve some of the infrastructure constraints that led to a glut of oil at the Cushing hub. The pipeline began operating in January 2014 at 520,000 b/d; TransCanada plans to expand its capacity to 700,000 b/d.²⁸

Enbridge, Kinder Morgan, and Spectra have new or expansion pipeline projects in development that would ultimately increase the pipeline capacity to deliver oil from Alberta to the U.S. Midwest and U.S. Gulf Coast, and servicing areas in between.

Enbridge recently completed a number of pipeline expansions and is planning further expansions that will allow western Canadian crude oil to reach existing markets in the U.S. Midwest and Ontario and new markets in the U.S. Gulf Coast. These expansions include the replacement of its Line 3 pipeline, which when completed will have a capacity of 760,000 b/d. A number of other projects are also being developed, including expansion to the Alberta Clipper and Southern Access lines as well as construction of the Northern Gateway pipeline, which would end at a deepwater port in Kitimat, British Columbia. Northern Gateway would include a 525,000 b/d crude oil pipeline and a smaller parallel pipeline to carry condensate back to Alberta that is expected to begin in 2018.²⁹

Kinder Morgan aims to expand its existing Trans Mountain pipeline system by building a second pipeline within the same right-of-way. The expansion would increase Trans Mountain's capacity to 890,000 b/d.

The completion of either or both of the competing Kinder Morgan Trans Mountain and Enbridge Northern Gateway projects would create a new export outlet for oil sands. Additional pipeline capacity to Canada's west coast would reduce Canada's overland dependence on the U.S. market while providing access to growing Asian economies in the Pacific Basin, which could have important implications for trade flows and the prices received by Canadian crude oil producers. The proposed west coast projects must overcome opposition, particularly concerns about the risk of pipeline or tanker spills in British Columbia and among affected aboriginal First Nations groups.³⁰

Rail

The rapidly increasing supply of liquid fuels from the oil sands in western Canada has far outpaced pipeline capacity and the expansion efforts of the pipeline companies. With

infrastructure already in place serving the demand destinations for western Canadian crude, rail has proven to be an adequate substitute. In 2014, crude oil transported by rail reached 185,000 b/d,³¹ of which 140,000 b/d were exported to the United States. Compared to the previous year, exports by rail increased 172%. In 2014, 51% of crude oil exports by rail went to the East Coast (PADD 1), 40% went to the U.S. Gulf Coast (PADD 3), and 7% went to the West Coast (PADD 5).

The Canadian Association of Petroleum Producers (CAPP) projects that by 2016, Canada will transport up to 250,000 b/d of crude oil by rail, and crude oil by rail could grow up to 600,000 b/d in 2018 if the Keystone XL pipeline is not in place. Current rail loading capacity is estimated at 776,000 b/d.³²

Downstream

According to CAPP, Canada has 16 refineries with a total crude oil processing capacity of 1.9 million b/d. Western Canada's eight refineries have a total capacity of 711,000 b/d, and Eastern Canada's eight refineries have 1.2 million b/d of capacity.³³

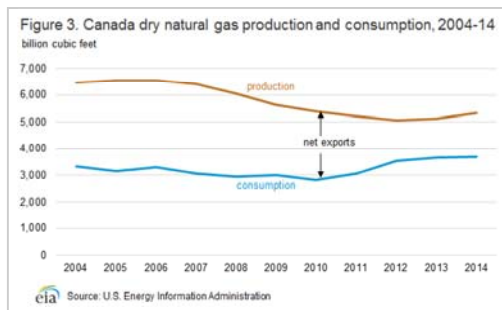
Sales of petroleum products in Canada averaged 1.8 million b/d in 2014, increasing roughly 2% compared with the previous year. According to CAPP, motor gasoline accounted for 42% of the refined petroleum products sold in Canada, with diesel fuel oil accounting for roughly 29%.³⁴

Natural gas

Canada is one of the world's largest producers of dry natural gas and the source of most U.S. natural gas imports.

Overview

Despite holding a smaller share of the world's proved natural gas reserves relative to crude oil, Canada ranked fifth in dry natural gas production and is a net exporter of dry natural gas (Figure 3). It is the fourth-largest exporter of natural gas, behind Russia, Qatar, and Norway. Although Canada has plans to export liquefied natural gas (LNG), all of Canada's current natural gas exports are sent to U.S. markets via pipeline.



Reserves

The U.S. Energy Information Administration (EIA) estimates that Canada's proved natural gas reserves were 67 trillion cubic feet (Tcf) at the end of 2014. Most of Canada's natural gas reserves are traditional resources in the WCSB, including those associated with the region's oil fields. Other areas with significant natural gas reserves include offshore fields near the eastern shore of Canada (principally Newfoundland and Nova Scotia), the Arctic region, and the Pacific coast.

Shale gas

Significant deposits of **unconventional natural gas** reside in the WCSB in the form of coalbed methane (CBM), shale gas, and tight gas, although they have not been developed as extensively as similar formations in the United States. Canada has an estimated 573 Tcf of unproved technically recoverable shale gas resources, according to [an updated assessment prepared by EIA](#). Five large sedimentary basins in western Canada with thick, organic-rich shales – the Horn River, Cordova Embayment, and Liard in northern British Columbia, the Deep Basins in Alberta and British Columbia, and the Colorado Group in central and southern Alberta – account for 536 Tcf of the total of technically recoverable shale gas resources. The Liard Basin claims the largest share of the total resource. The remaining

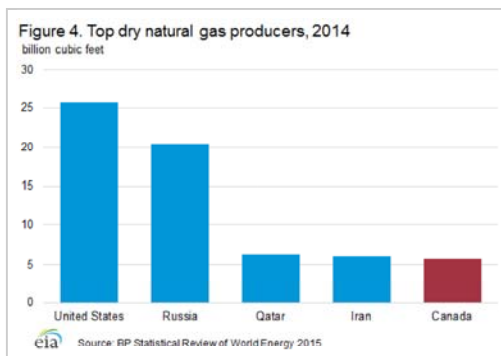
assessed resources are in the potential shale gas plays of Saskatchewan/Manitoba, Quebec, and Nova Scotia. Exploration in these three plays has been limited.

Exploration and production

In 2014, Canada was the fifth-largest producer of dry natural gas, behind the United States, Russia, Qatar, and Iran (Figure 4). Canadian dry natural gas production, which had decreased from 2002 to 2013, rose by about 200 billion cubic feet (Bcf) in 2014. Most of Canada's natural gas production occurs in the prolific WCSB. Alberta produced nearly two-thirds of Canada's gross natural gas in 2014, according to the NEB,³⁵ with most of the remaining volume coming from British Columbia.

Although Canadian natural gas production has been generally declining as a result of reserve depletion, technological advances have spurred rapid investment in the country. Natural gas production from the WCSB will increasingly come from shale gas, tight gas, and CBM. A number of major and independent companies, including Encana, Apache, Devon, and Quicksilver, are active in British Columbia's Horn River shale play.³⁶ Shale gas production in western Canada is currently relatively modest, and shale gas basins in eastern Canada are in even earlier stages of exploration and development.

Offshore natural gas production has been focused primarily off the coast of Eastern Canada, in the Scotian Shelf geological area near the province of Nova Scotia. The most prominent project is the Sable Offshore Energy Project (SOEP), in which ExxonMobil has a majority stake.³⁷ The project has been operating since 1999, with expansions and additions of new facilities continuing into 2007. Between January and August 2015 (latest available data), SOEP produced roughly 400 million cubic feet per day (MMcf/d) of raw natural gas.³⁸ Encana is developing another major natural gas project off Nova Scotia, the Deep Panuke Project, which began production in 2013. The project is designed to produce 300 MMcf/d and up to 892 Bcf during its life.³⁹



Trade

Virtually all of Canada's natural gas exports are transported to the United States via pipeline. In 2013, Canada began trucking very modest volumes of LNG to utilities in New England to meet inventory requirements in anticipation of winter demand in both 2013 and 2014. In 2014, total export volumes of LNG were less than one-third of an already modest amount that entered the United States in 2013. Canada also began exporting compressed natural gas (CNG) to the United States in 2014, totaling 303 MMcf.

The United States imported 2.6 Tcf of natural gas from Canada in 2014, of which one-tenth of 1% (435 MMcf) was LNG and CNG combined. Total U.S. imports of Canadian natural gas are significantly lower than the peak levels of 3.8 Tcf in 2002 and 2007. Canada is the source of nearly all (about 97%) of U.S. natural gas imports, most of which come from western provinces. *Although the United States is a net importer of natural gas from Canada*, it exported nearly 770 Bcf of natural gas to Canada in 2014, increasing significantly from levels seen a decade earlier. As prospects for domestic U.S. natural gas production continue to improve, the United States is expected to require lower natural gas imports while exporting more to its trading partners.

Pipelines

Canada's natural gas pipeline system is highly interconnected with the U.S. pipeline system. TransCanada operates the largest network of natural gas pipelines in North America, including 13 major pipeline systems and 42,100⁴⁰ miles of gas pipelines in operation. Within Canada, TransCanada operates a 25,100-mile network at a total average volume of 14

Bcf/d⁴¹ that includes the NGTL System, the Canadian Mainline, the Foothills, and the Trans Quebec and Maritimes that connect supply in western Canada to the United States. Spectra Energy operates a 1,800-mile, 2.9 Bcf/d pipeline system connecting western Canadian gas supply regions with markets in the United States and Canada.⁴² Spectra Energy also operates the Maritimes and Northeast Pipeline linking eastern Canadian supplies with consumers in the eastern United States. Enbridge and Veresen operate the Alliance Pipeline, a 1,423-mile pipeline system, delivering 1.3 Bcf/d from the WCSB to Chicago, Illinois, which is a significant source of natural gas and NGLs for the U.S. Midwest.⁴³

Liquefied natural gas (LNG)

Import terminals

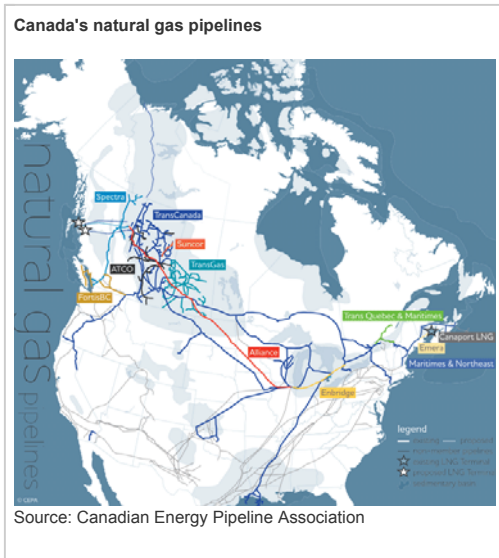
Because changes to North American natural gas supply fundamentals have diminished Canada's need for imported liquefied natural gas (LNG), plans for only two LNG terminals remain under consideration. Canaport, Canada's first and to date only operational regasification terminal, began importing LNG in June 2009. The Canaport terminal, operated by Repsol in partnership with Irving Oil, has a nameplate processing capacity of 1.2 Bcf/d⁴⁴. According to the BP Statistical Review of World Energy 2015, Trinidad and Tobago was the only source of Canada's LNG imports, supplying 21 Bcf in 2014.⁴⁵

Export terminals

The changing outlook for North America's natural gas is also supported by the number of applications for LNG export licenses in the United States and Canada. In Canada, 28 companies have applied for 35 LNG export licenses. As of September 2015, 12 of these applications were approved by the NEB. Most of the export terminals approved for development are on Canada's west coast in the province of British Columbia.⁴⁶

Kitimat LNG, a facility that was originally proposed as an import terminal, is now slated to become an export terminal, pending a final investment decision. Kitimat will initially process 1.3 Bcf/d of LNG, the feedstock for which will be shale gas produced in British Columbia.

LNG Canada is another project approved for exports. Shell, in cooperation with Mitsubishi, KoGas, and PetroChina, is pursuing a two-train, 1.6 Bcf/d export terminal near Kitimat that would come online in 2020. LNG Canada received a conditional approval by the British Columbia government, although the final investment decision may not be made until mid-2016.



Coal

As government policy attempts to lower domestic coal consumption, up to 50% of Canada's increasing coal production is being exported.

Reserves

Canada's total coal reserves stood at approximately 6.6 billion short tons in 2014, according to BP Statistical Review. More than 50% of the reserves are anthracite and bituminous coal.

The remaining reserves are subbituminous and lignite coal.⁴⁷ Coal resources are located across the country, but are actively mined and produced in only Alberta, British Columbia, and Saskatchewan.

Production and consumption

In 2014, Canada produced almost 69 million short tons of coal, a slight increase compared with the prior year. Roughly 50% of Canada's coal production is consumed domestically, a significant departure from a decade ago when Canada consumed nearly all of its domestic coal production. Increasing coal production and government policy aimed at reducing domestic coal consumption, along with the increased development of alternatives, has driven the increase in exports.

Coal is consumed domestically primarily for power generation; 18% of Canada's electricity generation is powered by coal. Coal is also consumed within industry, particularly steel and cement.⁴⁸

Electricity

Canada is a net exporter of electricity to the United States, and most of its power needs are met by hydroelectricity.

Generation

Canada generated an estimated 616 billion kilowatt-hours (kWh) of electricity in 2012, of which 61% was hydroelectric. Only China and Brazil produce more hydroelectricity than Canada. Fossil fuel plants satisfy most of Canada's electricity needs not met by hydroelectricity. According to the International Energy Agency, approximately two-thirds of Canada's conventional fossil-fueled generation is fueled by coal, with most of the remaining amount generated using natural gas and a small amount using oil.

Capacity

Canada had an estimated 135 gigawatts (GW) of installed electricity generation capacity in 2012. Hydroelectric dams accounted for approximately 75 GW of the total, including one of the largest hydroelectric complexes in the world, the 5.6 GW Robert-Bourassa Hydroelectric Generating Station on Quebec's La Grande River.⁴⁹ Canada is also a large and growing generator of wind powered electricity, mostly because of supportive policies at the federal and provincial levels. According to the Canadian Wind Energy Association, Canada's wind capacity was 10.4 GW as of September 2015. A record year in terms of wind energy developments, 2014 saw 37 new wind projects added, totaling 1.9 GW of capacity.⁵⁰

Trade

The electricity networks of Canada and the United States are highly integrated, and the United States is a net importer of electricity from Canada. In 2013, Canada exported 62 billion kWh of electricity to the United States, while importing 10.7 billion kWh. [The major electricity trade flows](#) from Canada to the United States occur from Manitoba to the U.S. Midwest and from eastern Canada into the New England, New York, and Midwest Regional Transmission Organizations. The U.S. Pacific Northwest is a net electricity exporter to Canada because its sizeable hydro capacity generates large amounts of electricity in excess of the region's need, particularly when river flows are high in the spring and early summer.⁵¹

Notes

- Data presented in the text are the most recent available as of November 10, 2015.
 - Data are EIA estimates unless otherwise noted.
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Endnotes

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