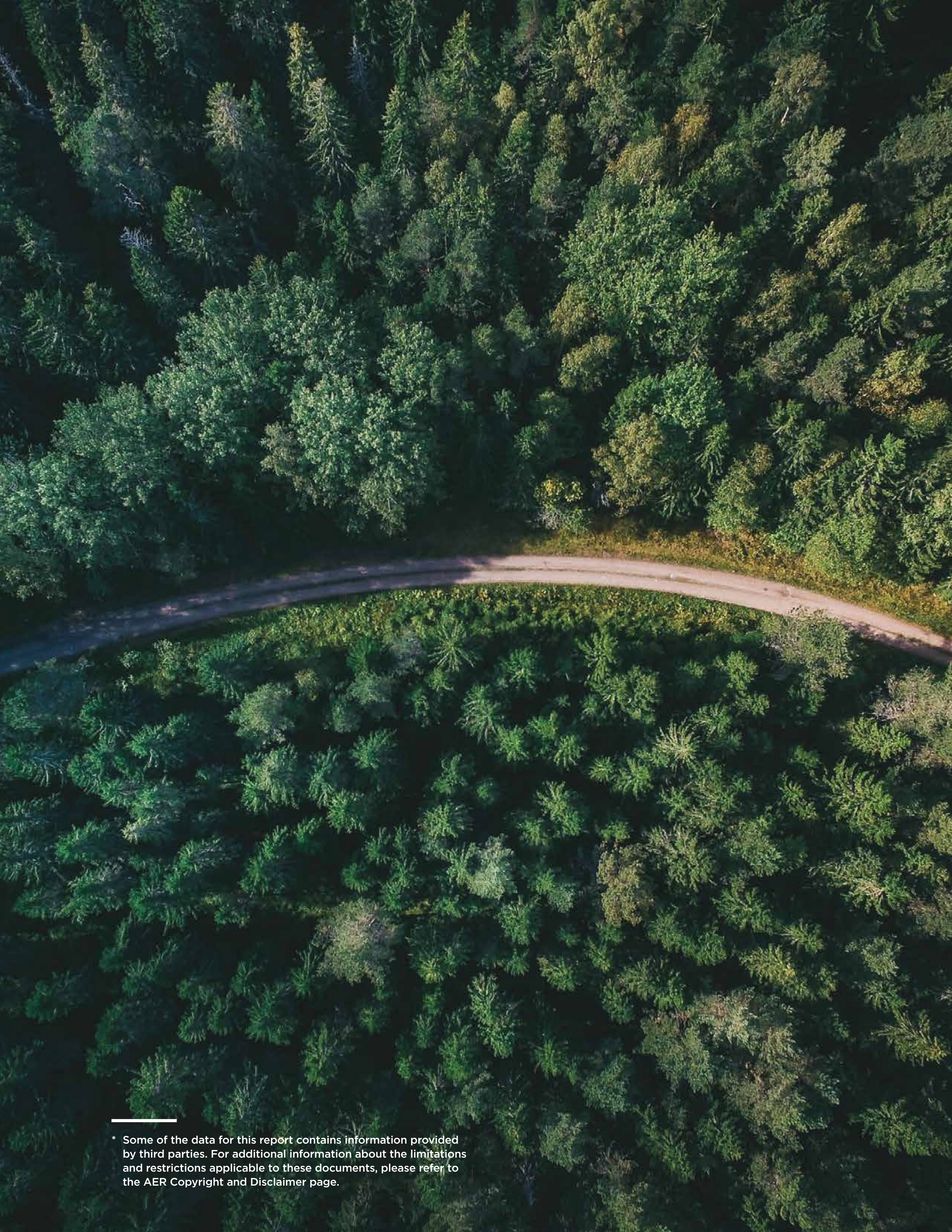
Alberta Energy Regulator

ALBERTA ENERGY OUTLOOK

ST98 | Executive Summary | **2020**



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EXECUTIVE SUMMARY

The Alberta Energy Regulator (AER) ensures the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources over their entire life cycle. As part of this mandate, we provide our stakeholders with credible information about Alberta's energy resources that can be used for decision making. A key part of this is *ST98: Alberta Energy Outlook (AEO)*, a report we issue annually with independent and comprehensive information on the state of reserves and the supply and demand outlook for Alberta's diverse energy resources: crude bitumen, crude oil, natural gas, natural gas liquids,[1] coal, and sulphur. This year's report also includes a new section on new reserve estimates for the Athabasca area. The AER has incorporated a new approach to assessing oil sands reserves in that region.

REPORT OVERVIEW

Emerging from the challenges at the end of 2018, the oil and gas industry in Alberta adjusted to and overcame several obstacles in 2019. Despite continued market access constraints and policy uncertainties, Alberta prices and production generally improved year-over-year. Because the industry is expected to face significant headwinds in 2020 largely due to effects of the coronavirus disease 2019 (COVID-19), two price cases, low-price and base-price, are highlighted in this year's *AEO*.

The North American benchmark prices for light sweet crude oil (West Texas Intermediate [WTI]) and natural gas (Henry Hub) decreased in 2019 relative to 2018, but Alberta producers were able to capture a higher price for their oil and gas. The Canadian Light Sweet (CLS), Western Canadian Select (WCS), and Alberta's natural gas at AECO-C prices increased, narrowing the gap with the U.S. prices. Improvements in market access, key U.S. refineries coming back on line, and Alberta's production curtailment rules played a significant role in narrowing the price differentials between the province and the United States. Pipeline project delays, maintenance schedules, and the higher cost of rail service are still persistent challenges contributing to the difference between Alberta's pricing and the North American benchmark.

Alberta's crude oil producers started the year with a significant improvement in oil prices after the implementation of the curtailment rules in January 2019. The differential between WCS and WTI decreased from US$42.71 per barrel (bbl) in December 2018 to US$17.08/bbl in January 2019 and remained under US$13.00/bbl for most of the year. Even though crude-by-rail transportation increased in 2019, narrow differentials proved to be challenging to producers considering rail due to transportation economics. A narrow differential does not provide enough incentive to cover the higher cost of transportation by rail. An estimated price differential between US$15.00/bbl and US$20.00/bbl is considered to be an economic range for exporting oil by rail from Alberta to key destinations in North America, including the U.S. Gulf Coast. As the curtailment program relaxed and price differentials widened, producers with long-term rail contracts and facilities increased rail volumes starting in the second quarter in 2019.

In the first quarter of 2019, the prices of CLS and WCS averaged Cdn$62.53/bbl and US$42.61/bbl, respectively.

[1] *Natural gas liquids refers to ethane, propane, butanes, and pentanes plus—on their own or combined—obtained from processing raw gas or condensate.*

Prices improved as downstream demand returned, export capacity improved, and curtailment rules balanced the supply of oil to meet removal capacity. In the second quarter of 2019, the price of CLS averaged Cdn$72.23/bbl and the price of WCS averaged US$49.14/bbl, each up 15 per cent from the first quarter. However, prices slightly declined in the third quarter due to production quota increases and refinery and pipeline outages in key markets. The price of CLS and WCS, averaged Cdn$66.95/bbl and US$41.13/bbl, respectively in the fourth quarter. Over 2019, the price differential between CLS and WTI and WCS and WTI averaged Cdn$5.99/bbl and US$12.74/bbl, respectively.

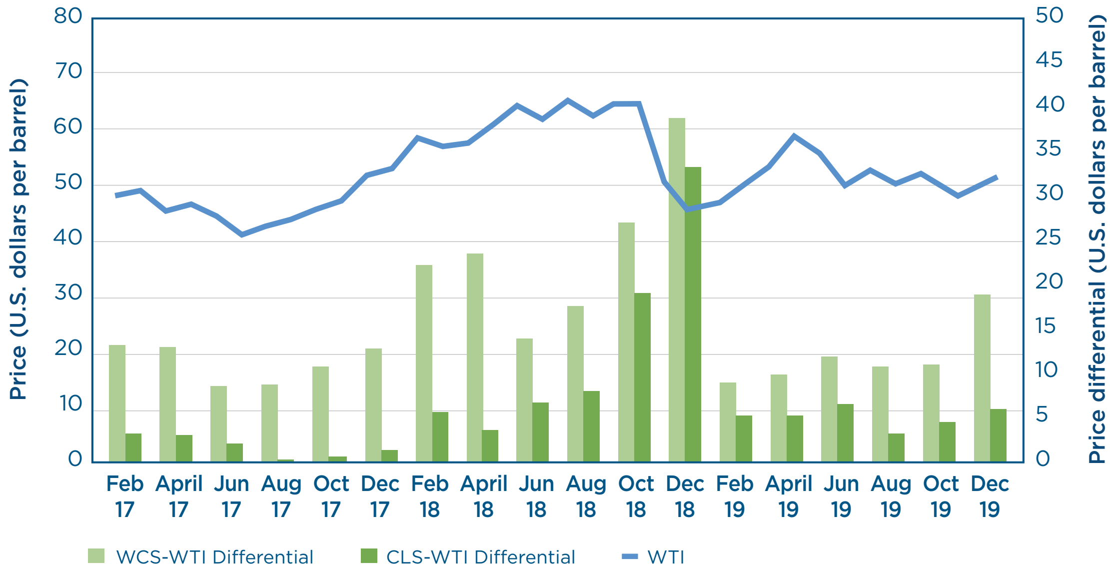
Despite the production quotas enforced by curtailment rules, the removal of pipeline bottlenecks and increased demand resulted in a 2 per cent increase in the production of oil and equivalent in 2019.

The past year remained challenging for the natural gas industry in Alberta due to weak and volatile natural gas prices. AECO-C, the benchmark price for natural gas in Alberta, started the year at an average of Cdn$1.75 per gigajoule (GJ) in January 2019 and remained under Cdn$2.50/GJ for the rest of the year. Gas prices remained low because the pace of western Canadian natural gas production outstripped demand growth. Prices were further affected by scheduled pipeline maintenance during the summer, resulting in export pipelines reaching capacity. TC Energy's NGTL system implemented some flexibilities in its system to enable easier storage injections during service disruptions in September 2019, which stabilized prices towards the end of the year.

Marketable production of natural gas in Alberta decreased in 2019 as production increases from oil wells and shale failed to offset production declines in the rest of the province. Producers remained focused on drilling for higher value natural gas liquids. With low natural gas prices, abundant supply, and transitions towards cleaner-burning fuels, demand for natural gas is expected to grow at all levels: provincial, national, and global.

Consumption in the oil sands, petrochemical energy diversification programs, the phase out coal-fired electricity, and Canadian liquefied natural gas (LNG) export projects, all have the potential to increase demand for Alberta's natural gas even further.

Figure 1 Canadian oil price differentials



Globally, capital spending in the oil and gas sector increased in 2019, but total capital expenditures in Alberta decreased by an estimated 12 per cent to Cdn$24.2 billion in the same period. This primarily resulted from low crude oil and natural gas prices and market access constraints. These factors negatively affected investment decisions, drilling programs, and project development. Capital expenditures in Alberta are anticipated to focus on developments with lower capital cost requirements and shorter investment cycles such as drillings in low-permeability resources, in addition to reducing debt.

The Federal Government passed Bill C-69 in June 2019, with the new legislation focused on reforming the federal environmental assessment regime in Canada. One of these changes was the replacing of the *Canadian Environmental Assessment Act 2012 (CEAA)* with the *Impact Assessment Act (IAA)*, which came into force August 2019. The IAA establishes a new regime for assessing the impacts of certain, designated major infrastructure projects and physical activities in Canada with the potential for adverse effects. In addition to large energy projects already considered under CEAA—such as pipelines, refineries, upgraders and mines—certain in situ oil sands facilities are now also covered by the IAA due to their potential impacts. However, these in situ facilities are exempt from federal review so long as the province they are within has some type of emissions limit, like Alberta's 100 megatonne cap.

Figures 2-13 will highlight the prices, capital expenditures, and supply and demand outlook for 2020 to 2029 (the forecast period) for Alberta's hydrocarbons and a snapshot of the province's reserves as of December 2019.

REPORT HIGHLIGHTS

Oil and Gas Production

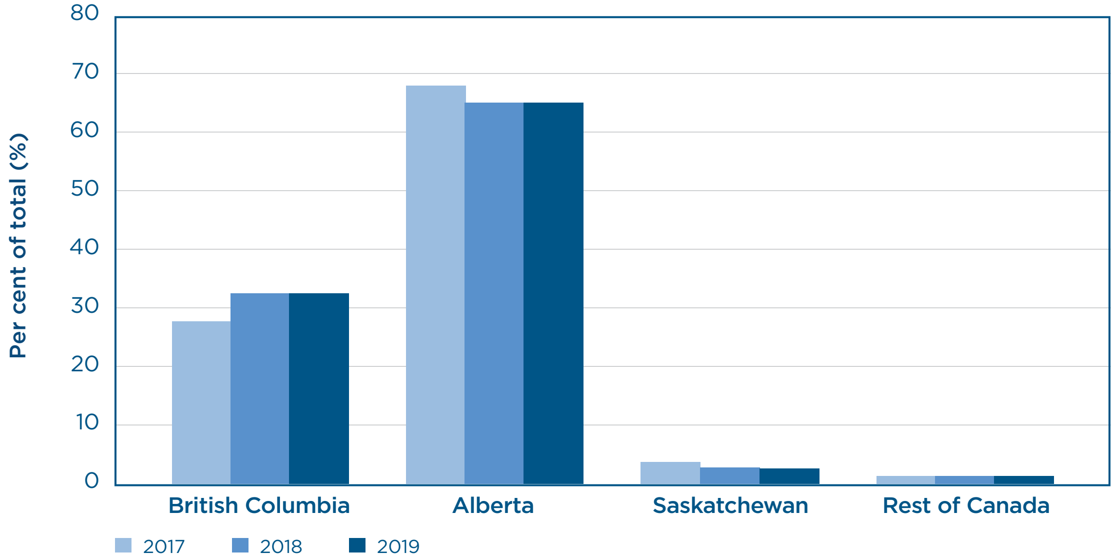
- Alberta remains the largest producer of natural gas and oil in Canada. In 2019, Alberta produced 65 per cent of Canada's natural gas and 82 per cent of Canada's oil and equivalent.[2] Almost 64 per cent of Canada's total oil and equivalent production was marketable bitumen.
- Alberta's raw crude bitumen production in 2019 approached 3.1 million barrels per day (10^6 bbl/d), a 2 per cent increase from 2018.

Oil and Gas Prices

- The price of WTI decreased by 12 per cent in 2019 and averaged US$57.01/bbl.
- For the third consecutive year, the price of CLS increased and averaged Cdn$67.71/bbl, a 3 per cent increase from 2018.
- The price of WCS increased by 15 per cent from 2018, averaging US$44.28/bbl.
- The WTI price in the base-price case is projected to be lower in 2020 at US$35.00/bbl, reflecting the effects of restored global oil demand following the coronavirus disease 2019 (COVID-19) pandemic and continued efforts by the Organization of Petroleum Exporting Countries (OPEC) and its partners to manage supply. Other factors which could create volatility in oil prices include U.S. production growth, OPEC's ability to maintain compliance, managing trade disputes and disruptions, and other geopolitical tensions.
- The low-price case of US$28.00/bbl in 2020 primarily considers prolonged weakness in global oil demand, noncompliance amongst OPEC members, and stronger than anticipated production growth, primarily in the United States.

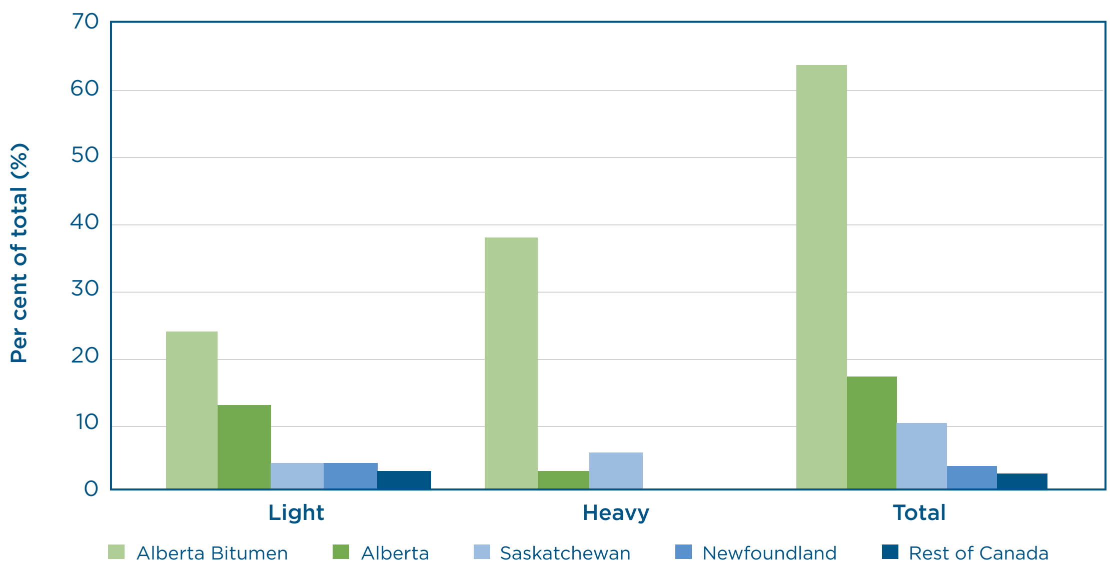
[2] Oil and equivalent includes light, medium, heavy, and ultra-heavy crude oil; condensate (pentanes plus); and upgraded and nonupgraded bitumen (referred to as marketable bitumen).

Figure 2 Marketable natural gas percentage of production—Canada



Source: Canada Energy Regulator.

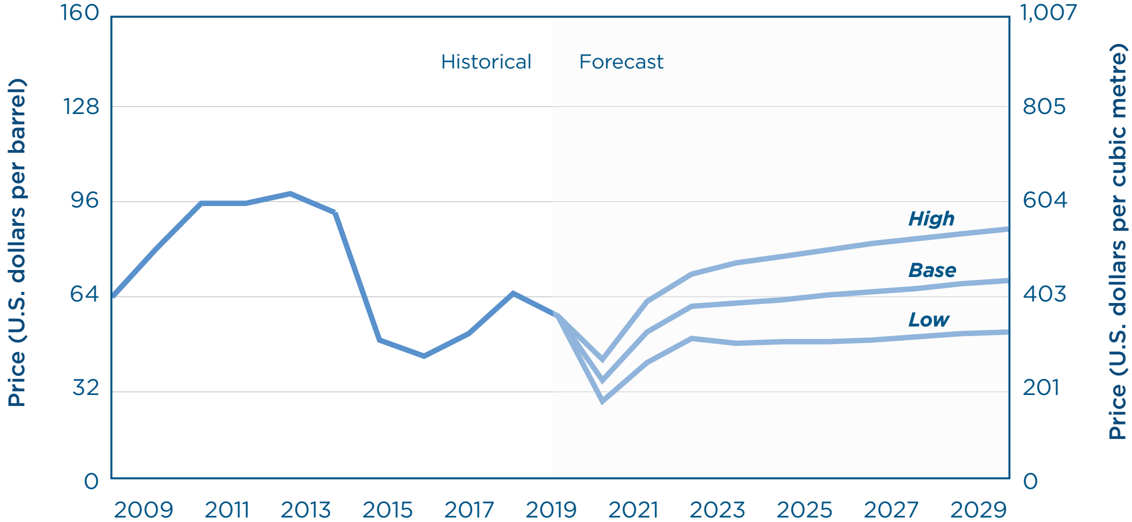
Figure 3 Oil and equivalent percentage of production—Canada



Source: Canada Energy Regulator.

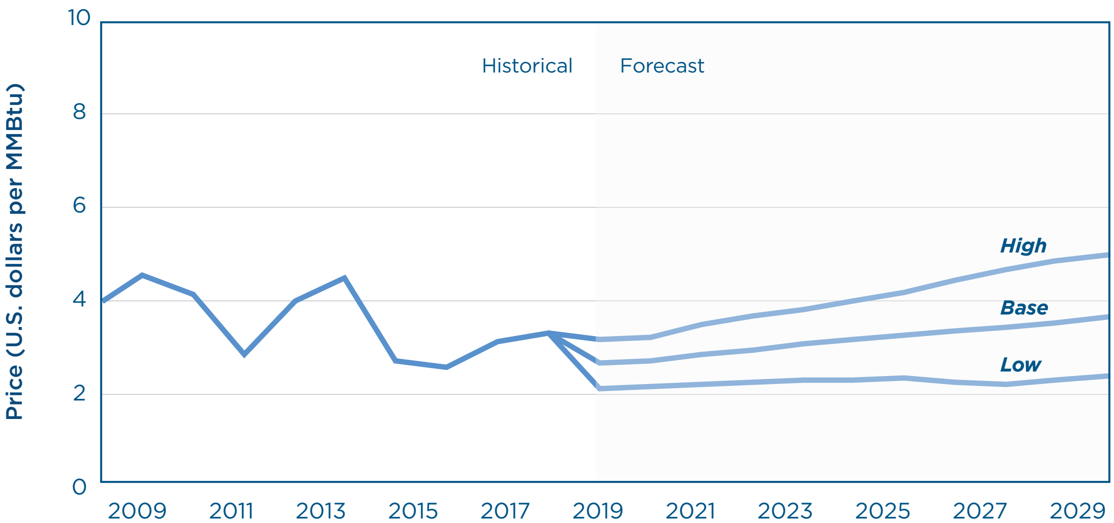
- The high-price case of US$42.00/bbl in 2020 depends on high compliance with OPEC's decision, geopolitical tensions constraining significant oil supplies, a substantial slow down in U.S. shale oil production, and a stronger-than-anticipated growth in the world economy.
- The WTI crude oil price is forecast to gradually strengthen to US$68.92/bbl by 2029 in the base-price case, with prices in the low- and high-price cases reaching US$51.69/bbl and US$86.15/bbl, respectively.
- The differential between WTI and WCS narrowed in 2019 compared with 2018 mostly due to the implementation of the curtailment rules by the Government of Alberta to balance the supply of oil with removal capacity and refinery demands. As a result, the differential averaged US$12.74/bbl in 2019, 52 per cent smaller than the US$26.28/bbl average differential in 2018.
- The Henry Hub natural gas price decreased to an estimated US$2.57 per million British thermal units (MMBtu) in 2019, an 18 per cent decrease. Increased U.S. natural gas production, including associated gas produced alongside tight oil, placed pressure on North American prices in 2019.
- In 2020, the price is forecast to decrease slightly to US$2.25/MMBtu because U.S. production is anticipated to continue to outpace the growth in demand.
- In the low-price case, the price is forecast to average US$1.80/MMBtu because of stronger-than-anticipated production and delayed development of LNG export facilities.
- In the high-price case, the price is forecast to average US$2.70/MMBtu due to lower associated gas produced, growth in domestic demand, and increasing exports of U.S LNG.
- The Henry Hub natural gas price is forecast to gradually strengthen to US$3.48/MMBtu by 2029 in the base-price case, reflecting balanced supply and demand with U.S. LNG exports and exports to Mexico anticipated to increase and relieve pressure on oversupplied markets. By 2029, prices in the low- and high-price cases are expected to reach US$2.33/MMBtu and US$4.63/MMBtu, respectively.

Figure 4 Price of West Texas Intermediate



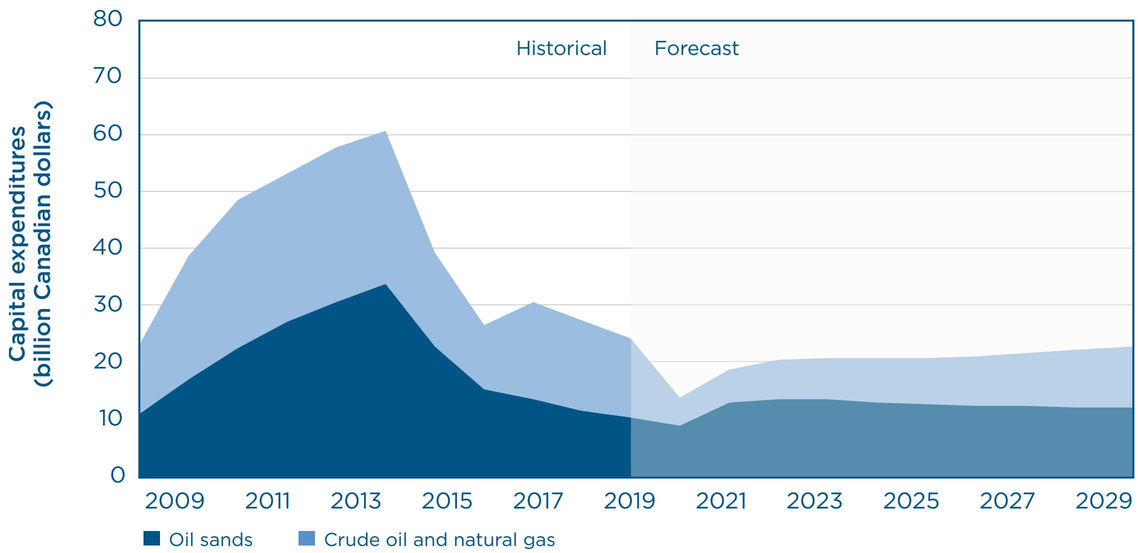
Historical values from U.S. Energy Information Administration.

Figure 5 Henry Hub natural gas price



Historical values from U.S. Energy Information Administration.

Figure 6 Alberta oil and gas and oil sands capital expenditure



Historical values from the Canadian Association of Petroleum Producers.

CAPITAL EXPENDITURES

- Total capital expenditures in the crude oil and gas and oil sands sectors decreased by 12 per cent in 2019, falling to Cdn$24.2 billion.[3] This was primarily driven by uncertainties around energy policy, low energy prices, and market access constraints.
- Capital expenditures in crude oil and natural gas decreased to an estimated Cdn$13.6 billion in 2019, which is 14 per cent lower than it was in 2018. This primarily resulted from low crude oil and natural gas prices and market access constraints. These factors negatively affected investment decisions, drilling programs, and project development.
- In 2019 the Government of Alberta announced several initiatives in attempts to spur investment and reduce market uncertainty including royalty guarantees, lower Alberta corporate tax rates, the relief for shallow gas producers, enhanced capital cost allowances, and exemptions to the curtailment rules.
- Oil sands capital expenditures continued to decrease from an estimated Cdn$11.7 billion in 2018 to an estimated Cdn $10.6 billion in 2019, a level of spending not seen since 2005. Continued deferral of large projects lowered the need for capital spending. Although some companies had focused on lowering debt and repurchasing stocks, most capital expenditures in the oil sands are projected to be primarily focused on sustaining capital, debottlenecking, and expanding existing projects.
- Reflecting market uncertainties and the AER's price cases, total capital expenditures are forecast to decrease in 2020, ranging between Cdn$14.1 billion and Cdn$16.4 billion. Investment is projected to grow modestly over the forecast period, with a balanced share of investment between the oil sands and the crude oil and natural gas sectors.

[3] *Historical statistics obtained from the Canadian Association of Petroleum Producers' Statistical Handbook (2018 data). Capital expenditures for 2019 are estimates.*

Table 1 Resources, reserves, and production summary, 2019

	Crude bitumen		Crude oil		Natural gas[a]		Raw coal	
	(million m³)	(billion barrels)	(million m³)	(billion barrels)	(billion m³)	(trillion cubic feet)	(billion tonnes)	(billion tons)
Initial in-place resources	293,125	1,845	14,197	89.3	10,237	363	93.7	103.3
Initial established reserves	28,092	177	3,128	19.7	5,903	209.5	34.8	38.4
Cumulative production	2,292	14.4	2,886	18.2	5,122	181.8	1.7	1.8
Remaining established reserves	**25,800**	**162**	**269.8**	**1.7**	**781**[b]	**27.7**[b]	**33.1**	**36.6**
Annual production	179.7	1.130	28.1	0.176	109.6[c]	3.9[c]	0.019[d]	0.021[d]
Ultimate potential (recoverable)	50,000	315	3,130[e]	19.7[e]	6,276[f]	223[f]	620	683

Note: Columns may not add up due to rounding.
[a] Expressed as “as is” gas, except for annual production, which is 37.4 megajoules per cubic metre; includes coalbed methane.
[b] Measured at field gate.
[c] Includes coalbed methane and shale gas.
[d] Annual production is marketable.
[e] Does not include oil from tight oil or shale oil plays.
[f] Does not include coalbed methane and shale gas.

RESERVES

- The AER has been providing an independent appraisal of Alberta’s energy resources since 1961. The AER studies hydrocarbon extraction and ensures that energy resources are being extracted in an efficient and environmentally responsible manner.
- The information is used by the Government of Alberta to develop policies and regional land-use plans and by the energy industry to evaluate investment opportunities in Alberta.
- The AER has incorporated a new approach to assessing oil sands reserves. Information on the reserves estimates recoverable using steam-assisted gravity drainage (SAGD) technology from the McMurray Formation in the Athabasca Oil Sands Area can be found in the reserves section.
- **Table 1** shows the reserves determined for crude bitumen, crude oil, natural gas, and coal. According to Table 1, Alberta has reserves sufficient for many years of production.

PRODUCTION AND DEMAND

- Total primary energy produced in Alberta remained relatively the same in 2019,[4] largely due to growth in the oil sands sector offsetting lower natural gas production.
- Marketable bitumen production, which includes nonupgraded and upgraded bitumen, increased by 1 per cent in 2019 as a result of expansions at existing projects, and resumption of activity of previously suspended projects.
- Crude oil production decreased slightly in 2019 relative to the year before because of reductions in drilling activity due to market access and policy uncertainty, along with conservative capital spending programs.
- Marketable natural gas production continued to decline by 4 per cent compared with 2018 due to low natural gas prices caused by abundant supply from U.S. shale gas resources.
- In 2019, Alberta produced an estimated 13 595 petajoules (PJ) of energy from all sources or 6.1 million barrels per day of light-medium quality crude oil equivalent (10^6 BOE/d).
- In 2029, Alberta is projected to produce 15 461 PJ (6.9 10^6 BOE/d) of energy from all sources.
- Upgraded and nonupgraded bitumen production accounted for almost half of total primary energy production in 2019. This percentage is expected to grow over the forecast period, reaching about 56 per cent by 2029.
- In 2019, on the basis of energy content, natural gas liquids production was about 32 per cent higher than crude oil production. Production of natural gas liquids is expected to continue to be greater than production of crude oil over the forecast period.
- Total natural gas liquids production increased by 6 per cent in 2019 as companies continued to focus on liquids-rich natural gas development for its better economic return.

[4] The trends and growth rates may differ slightly when standard units of measure, such as cubic metres or tonnes, are compared. Various grades of energy commodities have different heating values, and any changes to their composition may yield slightly different numerical trends and growth rates.

Figure 7 Total primary energy production in Alberta

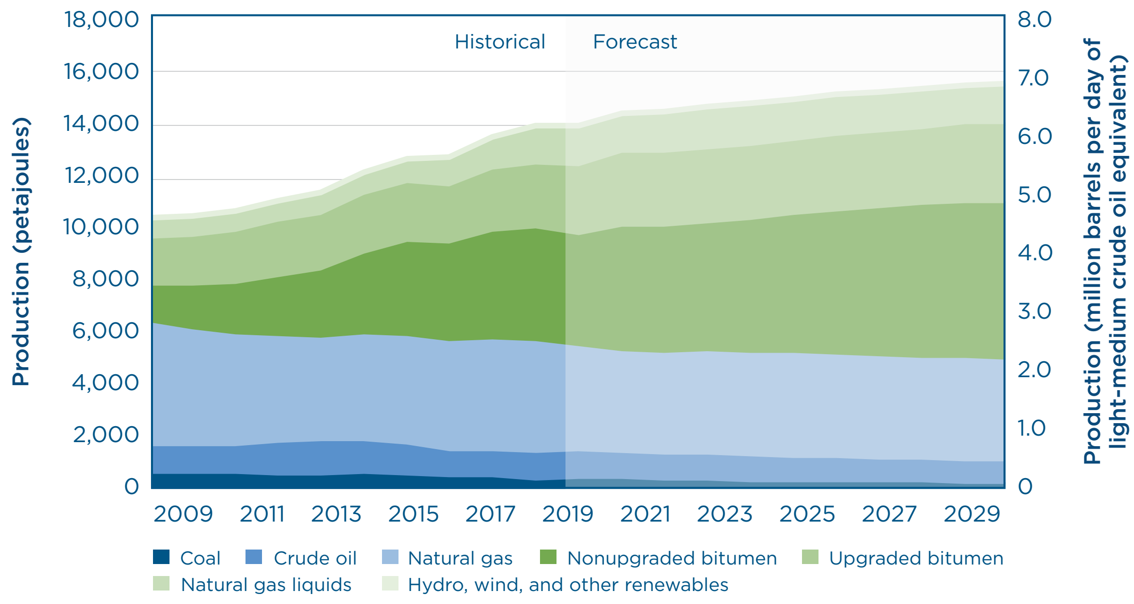
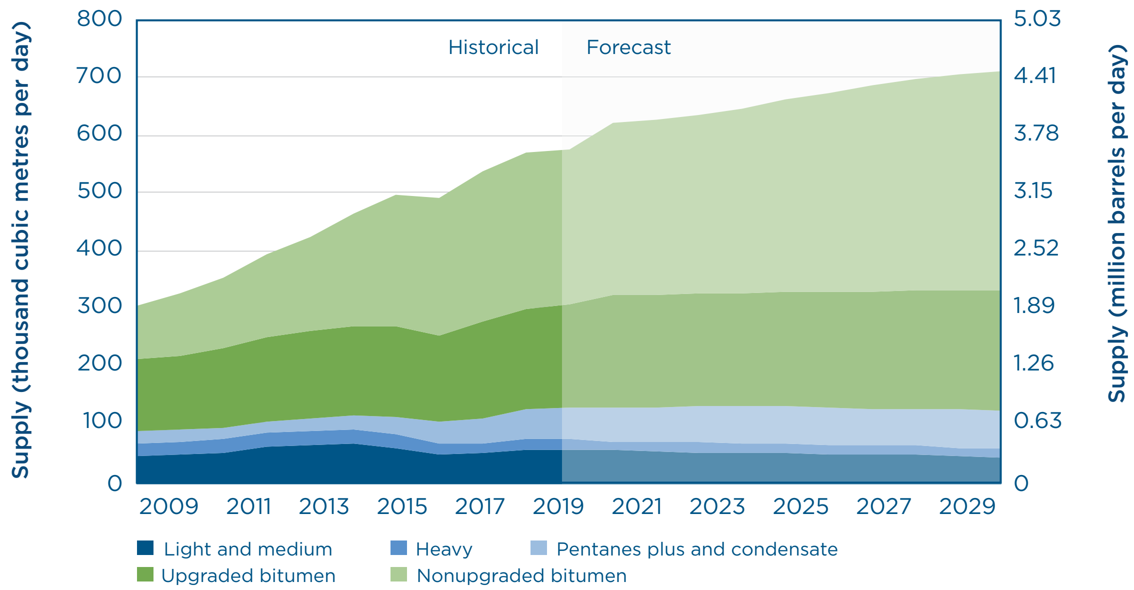
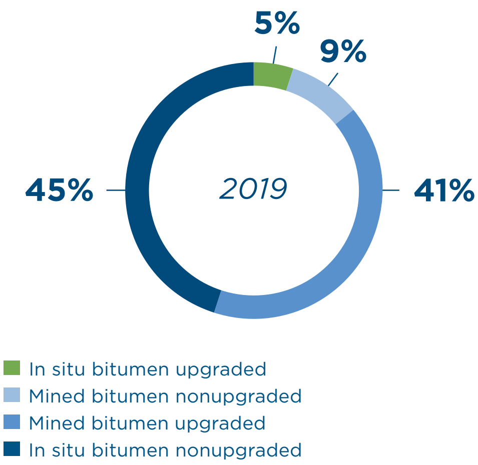


Figure 8 Alberta supply of crude oil and equivalent



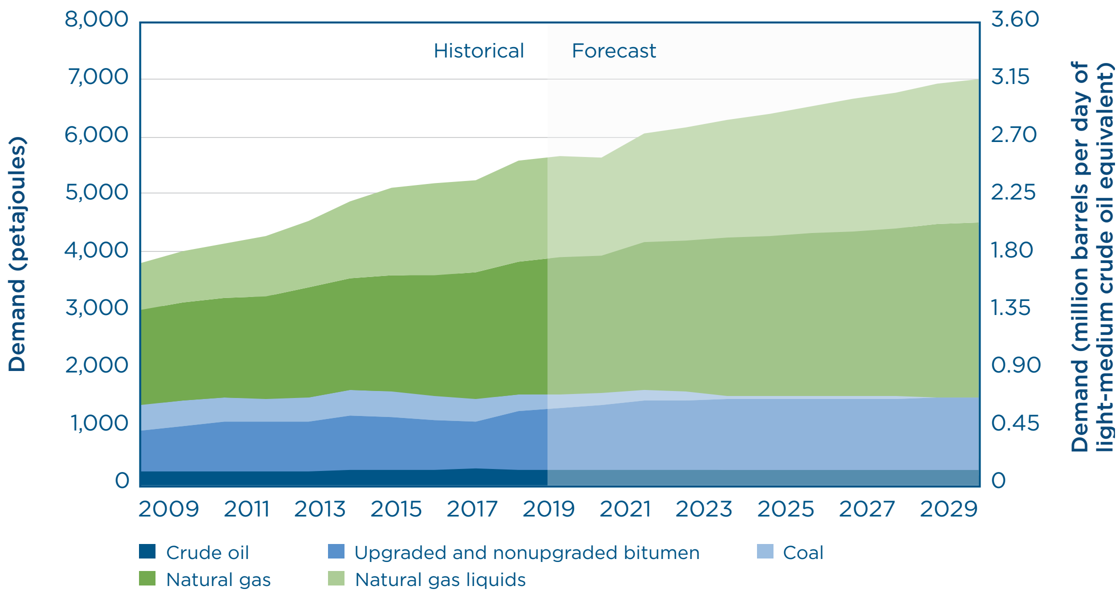
- Alberta's production of crude oil and equivalent increased by 1 per cent in 2019, reaching 3.6 10^6 bbl/d. The increase is largely attributed to growth in the supply of upgraded and nonupgraded bitumen and pentanes plus.
- Production of crude oil and equivalent is expected to continue to grow throughout the forecast period, reaching 4.4 10^6 bbl/d by 2029, driven primarily by growth in upgraded and nonupgraded bitumen production.
- Crude oil production decreased slightly in 2019 to 0.5 10^6 bbl/d. Production is forecast to decrease slightly over the forecast period, reaching 0.4 10^6 bbl/d by 2029.
- Pentanes plus production is forecast to grow from 0.3 10^6 bbl/d in 2019, reaching 0.4 10^6 bbl/d by 2029.
- In 2019, an estimated 46 per cent of produced raw bitumen was sent for upgrading in Alberta. By 2029, only about 41 per cent of bitumen is projected to be upgraded as raw production is expected to outpace upgrading capacity additions.
- Upgraded bitumen output for 2019 was up 5 per cent, largely due to restored capacity at Suncor and Syncrude's upgraders, both of which experienced operational challenges throughout 2018.

Figure 9 Percentage of mined and in situ bitumen sent for upgrading in Alberta



Total mined: 246.5 10^3 m³/d.
Total mined: 245.8 10^3 m³/d.

Figure 10 Primary energy demand in Alberta



- Total primary energy demand within the province increased by 1 per cent to 5671 PJ (2.5 10^6 BOE/d) in 2019. Alberta demand is projected to increase to about 6997 PJ (3.1 10^6 BOE/d) by 2029, largely because of both strengthening demand for pentanes plus as a diluent in bitumen blending and an increasing demand for natural gas because of the transition from coal to natural gas in power generation. Increasing production of bitumen is expected to increase the demand for natural gas even further. Alberta demand for bitumen is also forecast to increase with the projected provincial economic growth.
- Demand for coal from power generation is anticipated to decrease by about 90 per cent over the forecast period as a result of federal and provincial policies targeting a reduction in carbon dioxide emissions.
- Primary energy removals from Alberta decreased in 2019 by 1 per cent, because of reduced natural gas removals due to pipeline maintenance, reduced production and increased Alberta demand.

- Total primary energy removals from the province in 2019 were estimated at 9702 PJ (4.4 10^6 BOE/d), with oil (bitumen and crude oil) and natural gas liquids representing about 82 per cent of primary energy removals for the year.
- Removals from the province are projected to reach 11 062 PJ by 2029 (4.9 10^6 BOE/d), with upgraded and nonupgraded bitumen representing a growing share of primary energy removals.
- Natural gas removals from Alberta, are projected to decrease over the forecast period due to declining provincial production and increasing Alberta demand.
- For the second consecutive year, removals of coal grew at a high rate. Removals of marketable bituminous coal from Alberta increased by 62 per cent in 2019, reflecting continued marketing of higher value bituminous coal outside of Canada.
- In 2019, removals of crude oil, pentanes plus, upgraded bitumen, and nonupgraded bitumen were an estimated 530.2 thousand cubic metres per day (10^3 m^3/d) or 3.3 10^6 bbl/d.
- By 2029, about 683.1 10^3 m^3/d (4.3 10^6 bbl/d) of crude oil, pentanes plus, upgraded bitumen, and nonupgraded bitumen are forecast to be removed from the province. This projection assumes that most of these removals will go to the United States and that there will be sufficient transportation capacity (by pipeline and by rail) to ship these volumes.

Figure 11 Primary energy removals from Alberta

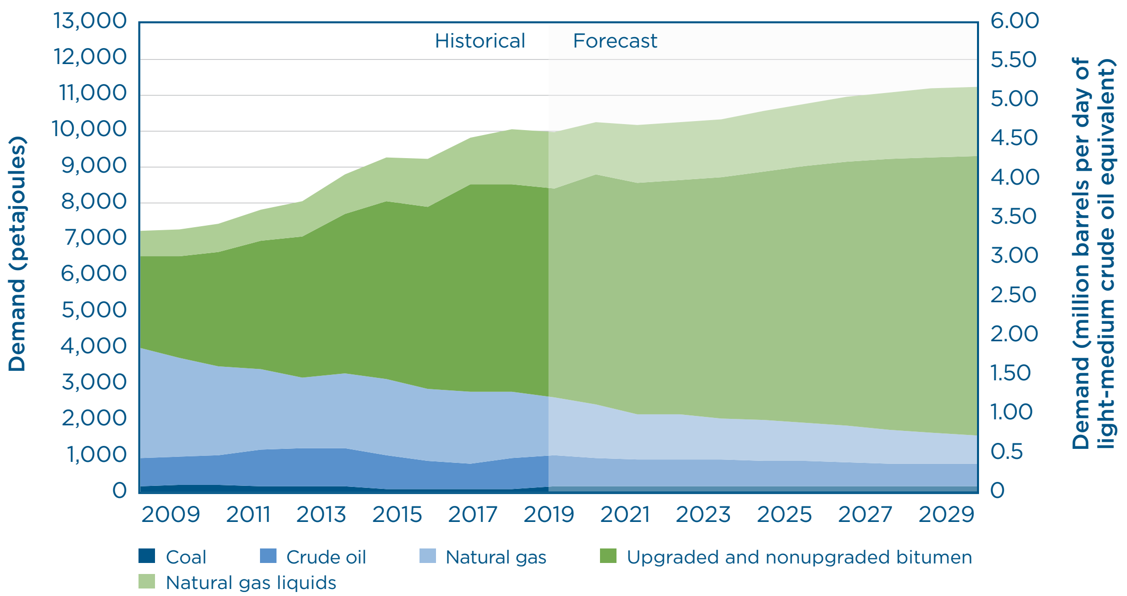


Figure 12 Total oil removals from Alberta

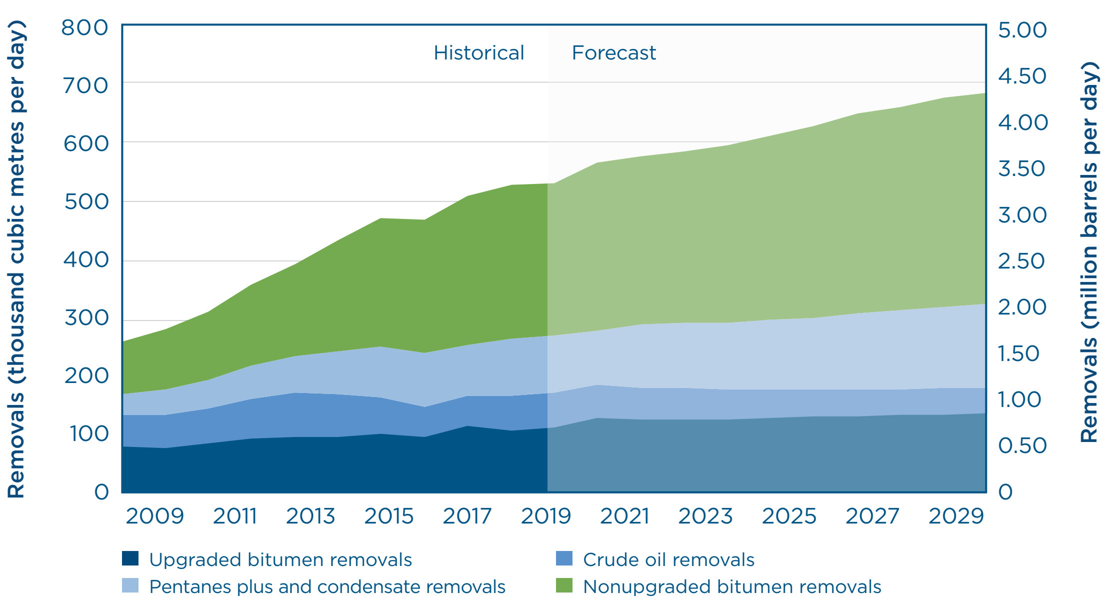
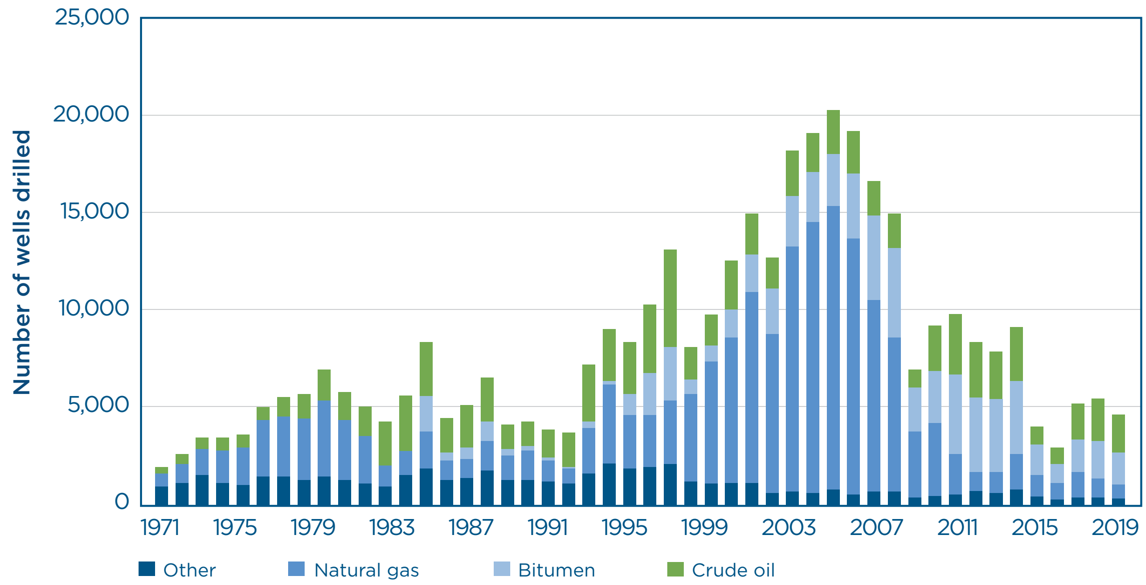


Figure 13 Historical drilling activity in Alberta



DRILLING ACTIVITY

- Total drilling decreased by 23 per cent in 2019 (natural gas drilling declined 27 per cent, crude oil drilling declined 20 per cent, and oil sands drilling declined 23 per cent). This is attributed to the lower level of investment in oil and gas in 2019.

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