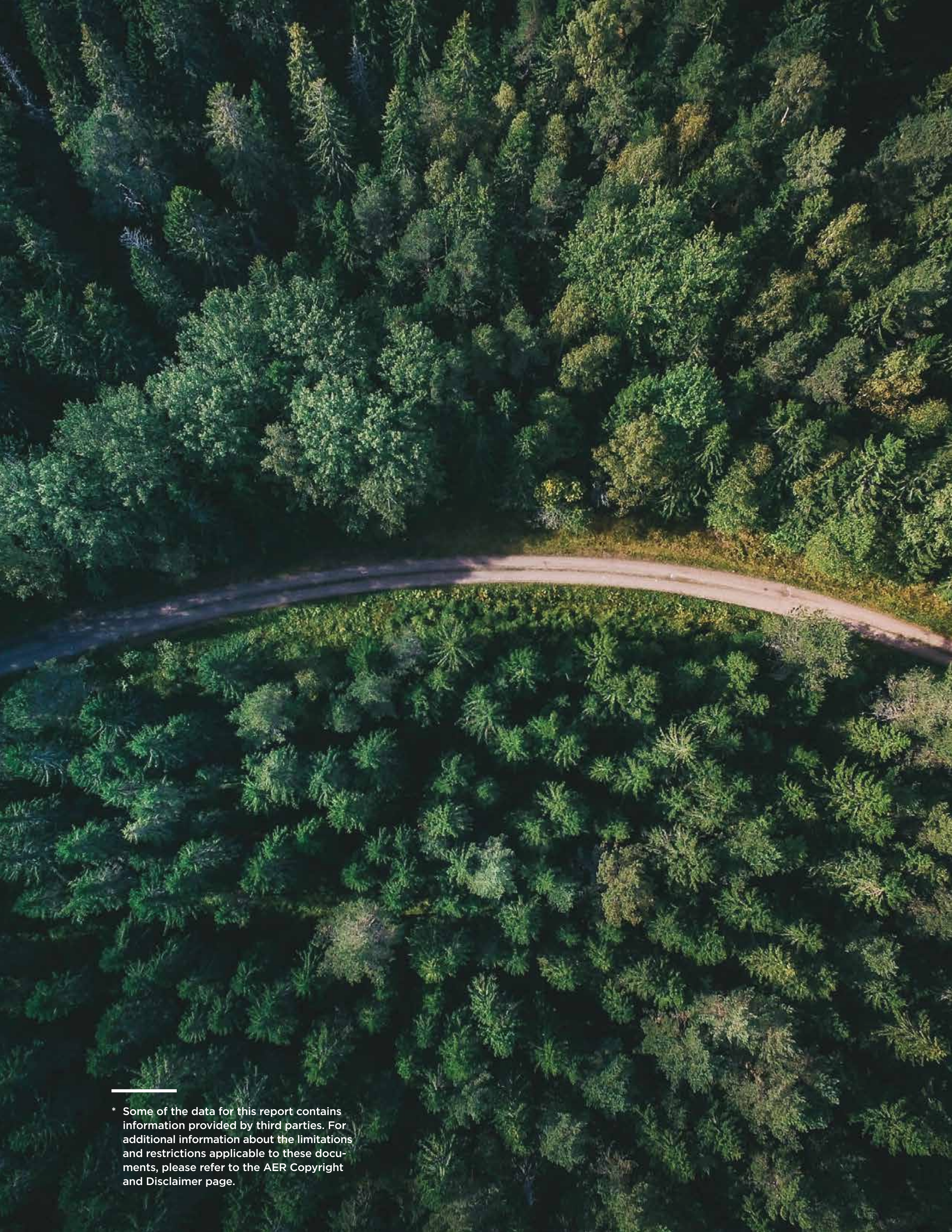
ALBERTA ENERGY OUTLOOK

ST98 | Executive Summary | 2021



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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, 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.

REPORT OVERVIEW

The global COVID-19 pandemic had significant repercussions for the oil and gas industry in 2020. Global oil demand reached historic lows given the global economic shutdown in many sectors. An unexpected supply surplus and rapidly filling storage capacity pushed oil prices into negative territory in April.

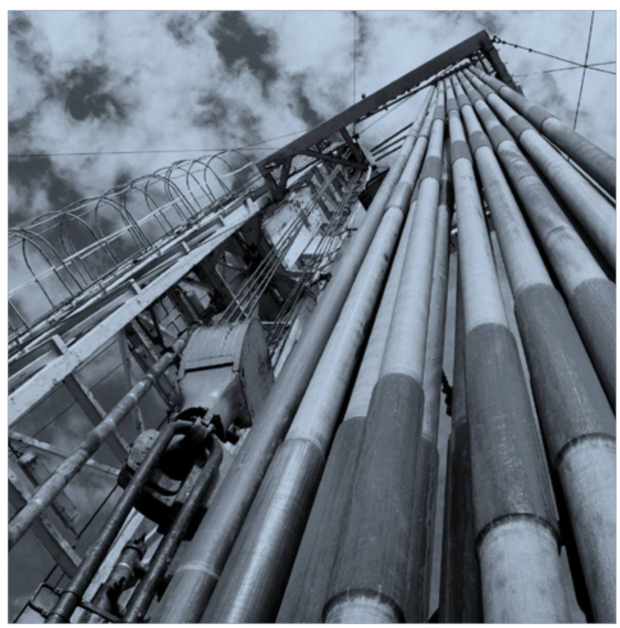
Oil prices rebounded in summer, in line with gradual removal of health restrictions and lockdowns, and coupled with voluntary supply cutback. Later in the year, expectations on the rollout of COVID-19 vaccines sustained the price increase.

The North American benchmark prices for light sweet crude oil (WTI) and natural gas (Henry Hub), and Alberta benchmark prices—Canadian Light Sweet (CLS) and Western Canadian Select (WCS)—all declined in 2020. AECO-C, the Alberta benchmark price for natural gas, increased due to low inventories during the same timeframe.

Alberta's crude oil producers saw an abrupt decline in CLS and WCS prices in the first months of 2020, to US$8.99 per barrel (bbl) and US$3.50/bbl, respectively. Prices rebounded through mid-summer, then increased more gradually through the end of the year.

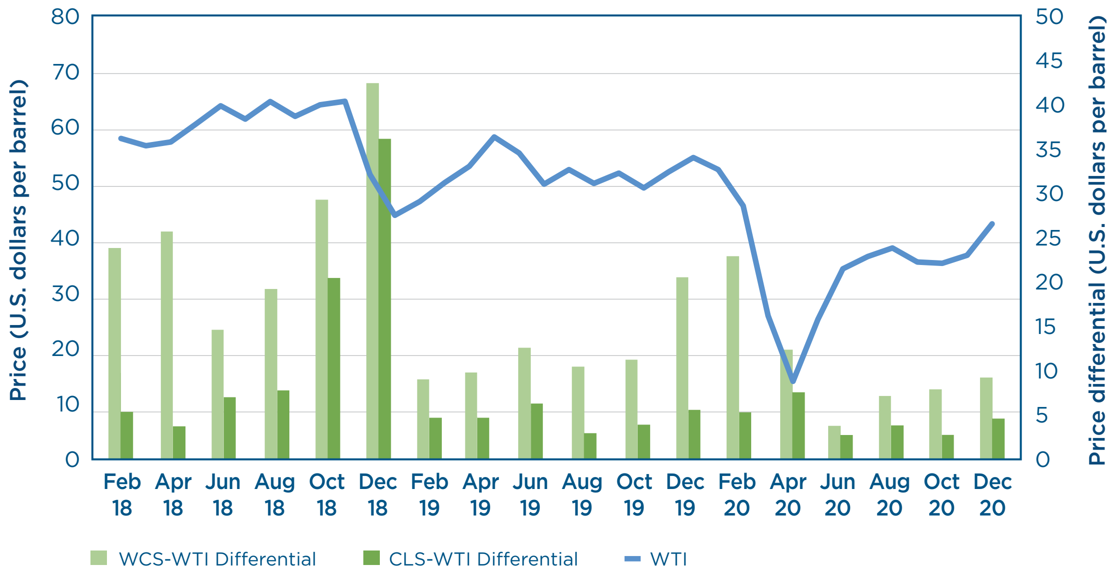
In 2020, the price differential between WTI and CLS and WTI and WCS averaged US$5.07/bbl and US$12.43/bbl, respectively, although they showed large fluctuations throughout the year. The average differentials in 2020 were narrower than 2019 averages.

The differential between WTI and WCS recorded a high of US$23.26/bbl in February and a low of US$4.34/bbl in June. In mid-April, the differential narrowed to less than US$10/bbl, when over 1 million barrels per day (10^6 bbl/d) of oil sands production was cut due to the COVID-19 pandemic. The differential between WTI and CLS recorded a high of US$8.88/bbl in January and a low of US$2.17/bbl in May.



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

Figure 1 Canadian oil price differentials



The narrow differentials did not provide enough incentive to cause a large shift to rail transport. The volume of crude oil moved by rail declined by 39 per cent in 2020 to 63 10^6 bbl/d.

Natural gas prices, including Henry Hub, fell at the onset of the COVID-19 pandemic. In contrast, AECO-C, increased because of low natural gas inventories in Alberta. AECO-C started the year at an average of Cdn$2.28 per gigajoule (GJ), dropped to Cdn$1.75/GJ in April, then gradually increased to Cdn$2.62/GJ by the end of the year. The natural gas price differential between Henry Hub and AECO-C narrowed substantially in 2020.

At the end of 2020, Alberta lifted the production limits that were first introduced in December 2018. However, production of oil and equivalent declined by 4 per cent in 2020 mainly due to lower fuel demand during the COVID-19 pandemic.

After declines in 2018 and 2019, marketable production of natural gas in Alberta stabilized in 2020. Production increases from shale and coalbed methane resources were enough to offset a decline in gas production from other sources for the year. Producers remained focused on drilling for higher-value natural gas liquids in the most productive areas of the province.

Over the forecast, electricity generation and oil sands sectors will account for most of the increase in Alberta's natural gas use. Demand for natural gas in electricity generation will be driven by coal-to-gas switching and cogeneration. Natural gas demand is expected to grow with production in in situ facilities. We anticipate there will be a growing demand from hydrogen manufacturing for natural gas by 2030.

Although oil prices increased significantly from the low levels seen in April 2020, high uncertainty about future prices did not lead to increased investments, which made the return on investments highly unpredictable. Total capital expenditures in Alberta decreased an estimated 30 per cent to Cdn$17.4 billion in 2020, in line with the historic drop in oil demand. Low energy prices, policy uncertainty, and market access constraints continued to impact drilling programs and large-scale bitumen projects. Capital expenditures are forecast to gradually increase but remain below peak levels seen in 2014.

With the cancelation of the Keystone XL by the new U.S. administration in the first quarter of 2021, and the Supreme Court of Canada's decision that federal carbon pricing is constitutional, industry's environmental, social and governance (ESG) standards are becoming increasingly relevant for attracting investment in Alberta oil and gas.

Notably, interest in helium sources has increased significantly both worldwide and in Alberta. To learn more, visit the Alberta Geological Survey.

REPORT HIGHLIGHTS

This section provides highlights of oil and gas production, prices, capital expenditures, demand, and drilling activity in 2020, and their outlook for 2021 to 2030 (the forecast period). A snapshot of the province's reserves as of December 2020 are also provided.

Oil and Gas Production

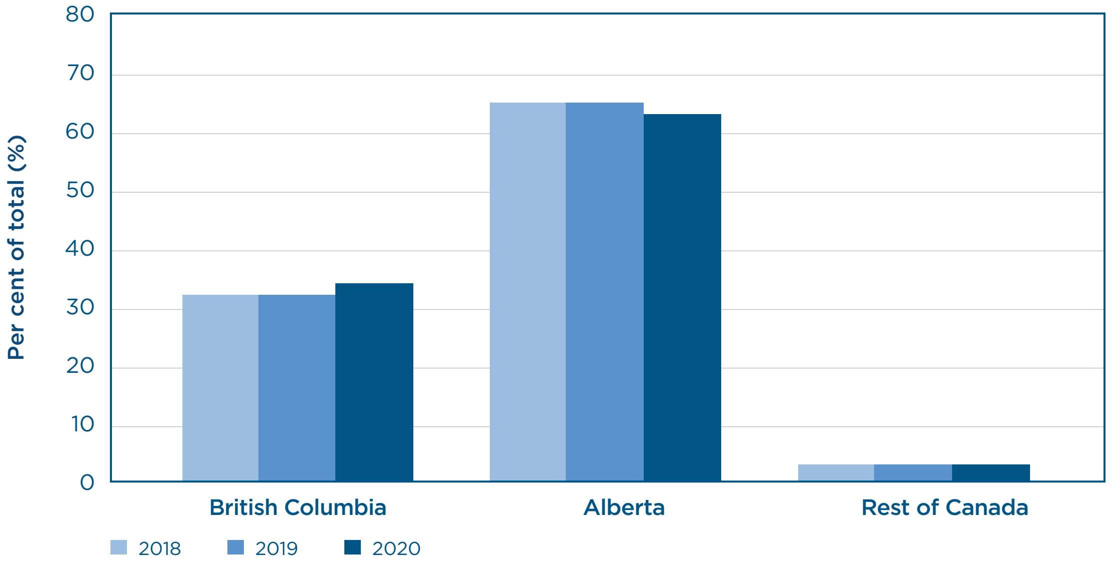
- Alberta remains Canada's largest natural gas and oil producer. In 2020, Alberta produced 63 per cent of Canada's natural gas and 83 per cent of Canada's oil and equivalent.[2] Almost 66 per cent of Canada's total oil and equivalent production was marketable bitumen.
- Alberta's raw crude bitumen production in 2020 was close to 3.0 10^6 bbl/d, a 4 per cent decline from 2019.

Oil and Gas Prices

- The price of WTI decreased by 31 per cent in 2020, averaging US$39.23/bbl.
- The price of CLS decreased by 32 per cent in 2020, averaging Cdn$45.77/bbl.
- The price of WCS decreased by 39 per cent in 2020, averaging US$26.81/bbl.
- The WTI base-price case is projected to be higher in 2021, at US$53.00/bbl. The forecast for 2021 assumes WTI prices will be supported by OPEC+s' commitment to restrain supply and a stronger global economy. However, the recovery in global demand could be challenged by new COVID variants.
- The low-price case of US$40.53/bbl in 2021 primarily considers reductions in global oil demand due to resurgence of new COVID-19 variants, noncompliance among OPEC+ members, and stronger than anticipated production growth, primarily in the U.S.
- The high-price case of US$69.32/bbl in 2021 depends on high compliance with OPEC's decision to restrain supply, stronger than anticipated growth of the world economy, and faster COVID-19 vaccination rollouts.

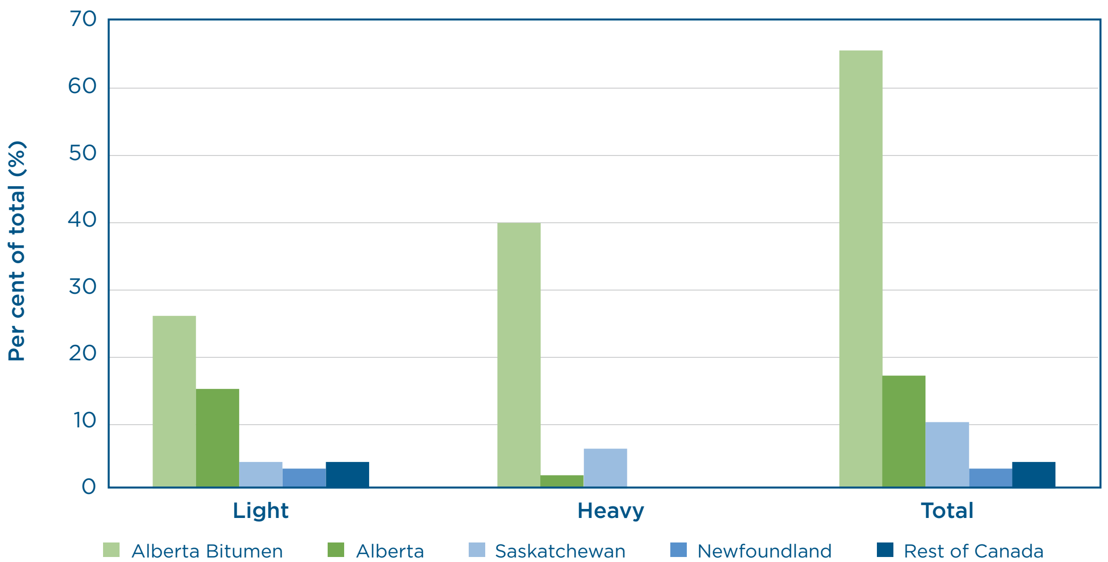
[2] Oil and equivalent includes light, medium, heavy, and ultra-heavy crude oil; condensate (pentanes plus); and upgraded and non-upgraded bitumen (referred to as marketable bitumen).

Figure 2 Marketable natural gas percentage of production—Canada



Source: Canada Energy Regulator.

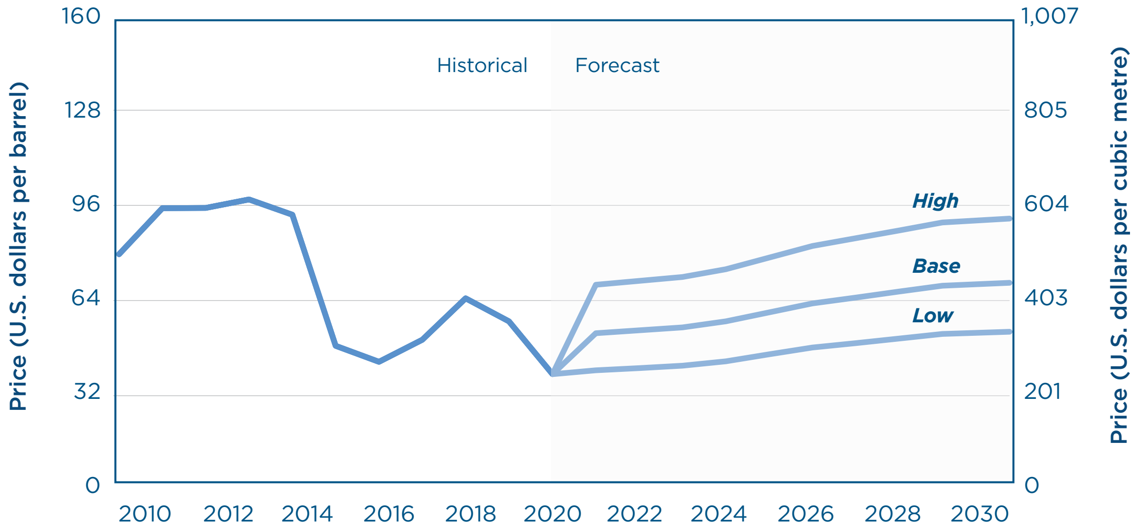
Figure 3 Oil and equivalent percentage of production—Canada



Source: Canada Energy Regulator.

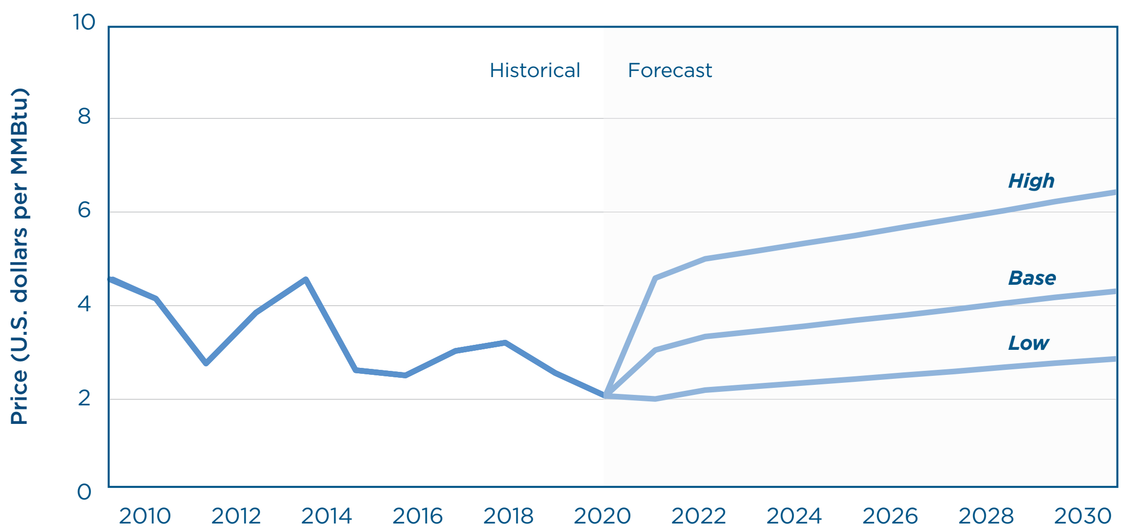
- The WTI crude oil price is forecast to gradually strengthen to US$70.00/bbl by 2030 in the base-price case, while the low- and high-price cases are forecasted to reach US$53.52/bbl and US$91.55/bbl, respectively.
- The differential between WTI and WCS decreased slightly in 2020 to US$12.43/bbl, compared with US$12.71/bbl in 2019. However, monthly averages showed large fluctuation, from prices as high as US$23.26/bbl in February to as low as US$4.34/bbl in June.
- The Henry Hub price decreased 17 per cent, averaging US$2.13 per million British thermal units (MMBtu) in 2020. Production fell due to drop in demand and low natural gas and crude oil prices.
- The price of Henry Hub is anticipated to increase to an average US$3.01/MMBtu in 2021. The effects of the COVID-19 pandemic on the global economy have slowed the demand for gas to a lesser extent than for oil. Recent increases in oil prices and a forecast of rising natural gas prices will contribute to associated gas production growth.
- In the low-price case, the price is forecast to average US$2.07/MMBtu in 2021, because of slower than expected economic recovery and demand.
- In the high-price case, the price is forecast to average US$4.39/MMBtu due to faster than expected economic recovery and demand.
- The Henry Hub natural gas price is forecast to gradually strengthen to US$4.14/MMBtu by 2030 in the base-price case, reflecting growing natural gas demand, and higher production costs, as producers increasingly drill in less prolific and more expensive production locations. By 2030, prices in the low- and high-price cases are expected to reach US$2.84/MMBtu and US$6.04/MMBtu, respectively.

Figure 4 Price of West Texas Intermediate



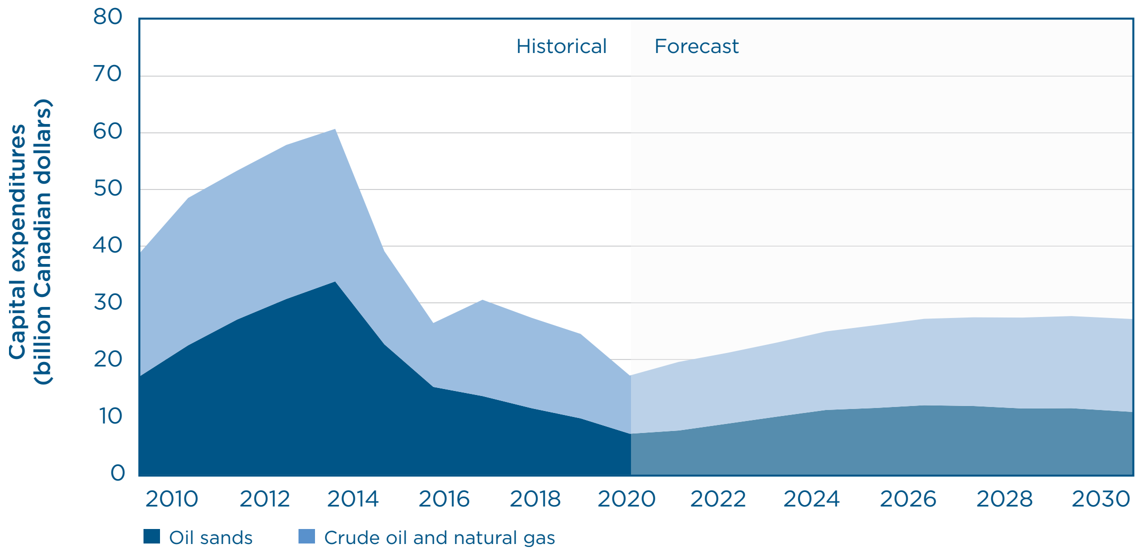
Historical values from U.S. Energy Information Administration.

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 30 per cent in 2020, falling to Cdn$17.4 billion.[3] The COVID-19 pandemic led to a historic drop in energy prices that impacted the investment environment.
- Capital expenditures in crude oil and natural gas decreased to an estimated Cdn$10.2 billion in 2020, a decline of 31 per cent from 2019. This was primarily due to lower drilling activity.
- Estimated oil sands capital expenditures decreased from Cdn$9.9 billion in 2019 to Cdn$7.2 billion in 2020, a level of spending not seen since 2005. Capital expenditures have been steadily decreasing since their peak in 2014, as producers focus less on new projects and more on expansions and efficiency enhancements.
- Total capital expenditures are forecast to increase to Cdn$19.8 billion in 2021, reflecting market uncertainties and the AER's price cases. Investment is projected to grow modestly over the forecast period, in line with economic recovery and corresponding price forecasts. By end of the forecast period, the total capital expenditures remain relatively low compared with the last decade.

[3] *Historical statistics obtained from the Canadian Association of Petroleum Producers' (CAPP) Statistical Handbook (2019 data). Capital expenditures for 2020 are estimates from CAPP.*

Table 1 Resources, reserves, and production summary, 2020

	Crude bitumen		Crude oil		Natural gas[a]		Raw coal	
	(million m^3)	(billion barrels)	(million m^3)	(billion barrels)	(billion m^3)	(trillion cubic feet)	(billion tonnes)	(billion tons)
Initial in-place resources	293,125	1,845	14,481	91.1	10,548	374.4	93.7	103.3
Initial established reserves	28,092	177	3,146	19.8	5,959	211.5	34.8	38.4
Cumulative production	2,465	15.5	2,883	18.1	5,204	184.7	1.7	1.9
Remaining established reserves	**25,627**	**161.3**	**263.0**	**1.7**	**755[b]**	**26.8[b]**	**33.1**	**36.5**
Annual production	173.1	1.089	24.6	0.155	105.1[c]	3.7[c]	0.014[d]	0.015[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.
- Table 1 shows the reserves determined for crude bitumen, crude oil, natural gas, and coal. The data suggests Alberta has reserves sufficient for many years of production.

PRODUCTION AND DEMAND

- Total primary energy produced in Alberta decreased by 3 per cent in 2020,[4] largely due to lower demand for energy and increased oil inventories caused by the COVID-19 pandemic.
- Marketable bitumen production, which includes nonupgraded and upgraded bitumen, decreased by 3 per cent in 2020, as producers responded quickly and adjusted their output in response to low demand and crude oil prices.
- Crude oil production decreased by 12 per cent in 2020 because of the same reasons stated above, which led to a decline in drilling activity and production.
- Total marketable natural gas production remained relatively unchanged in 2020. Lower natural gas output from conventional gas was offset by higher production from shale and coalbed methane resources.
- In 2020, Alberta produced an estimated 13 128 petajoules (PJ) of energy from all sources, or 5.9 million barrels per day of light-medium quality crude oil equivalent (10^6 BOE/d.
- In 2030, Alberta is projected to produce 15 888 PJ (7.1 10^6 BOE/d) of energy from all sources.
- Upgraded and nonupgraded bitumen production accounted for almost half of total primary energy production in 2020. This percentage is expected to grow over the forecast period, reaching about 56 per cent by 2030.
- In 2020, on the basis of energy content, natural gas liquids production was about 48 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.
- While butane and ethane production remained relatively flat, total natural gas liquids production decreased by 2 per cent in 2020, driven by a decline in propane and pentanes plus production.

[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

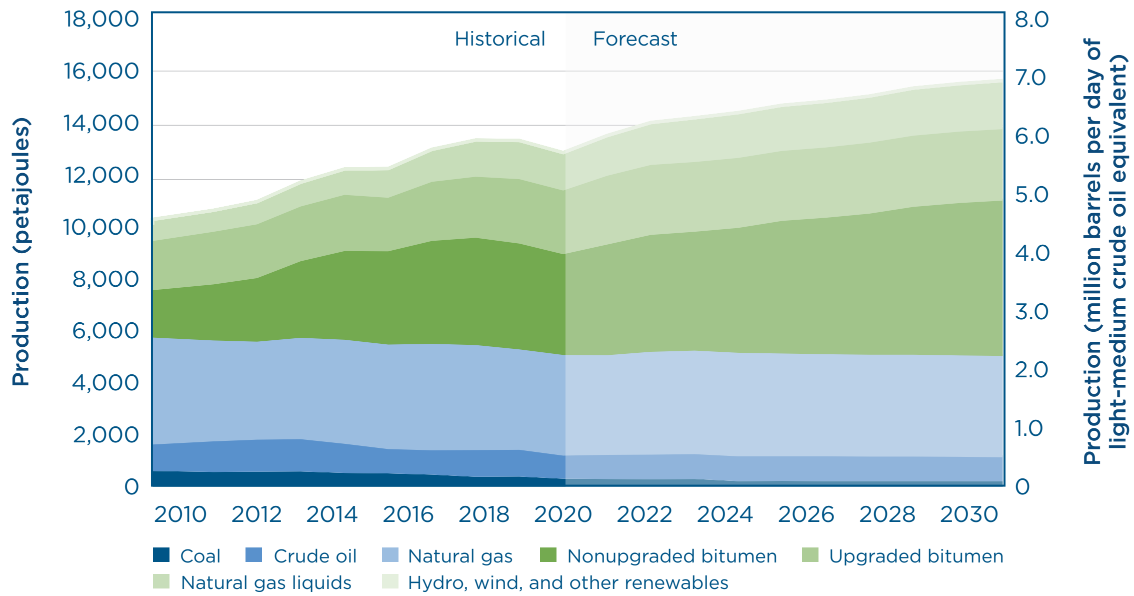
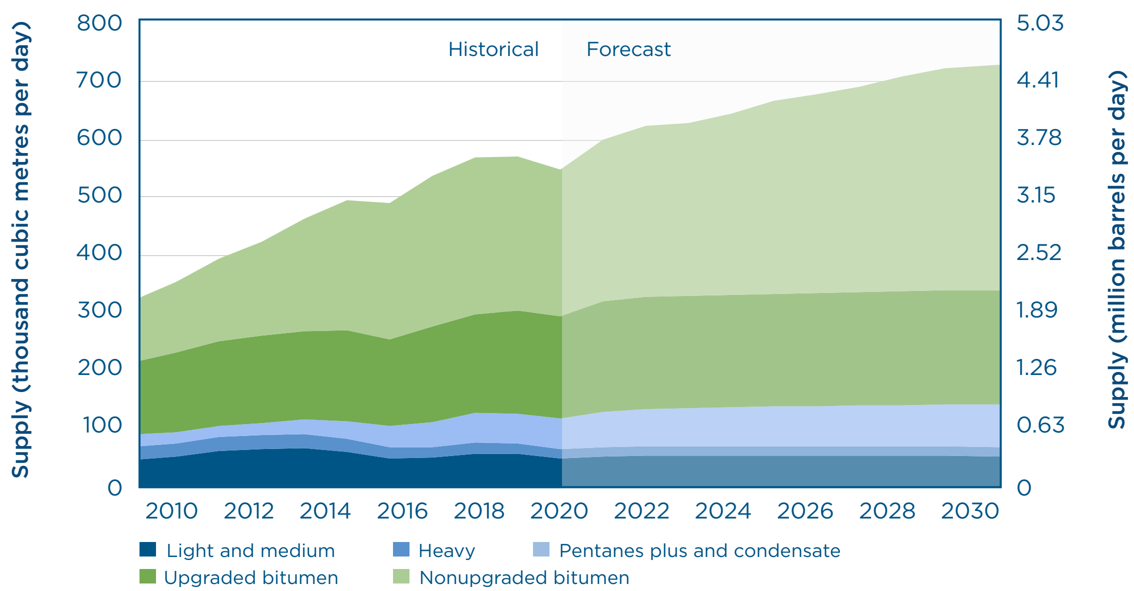
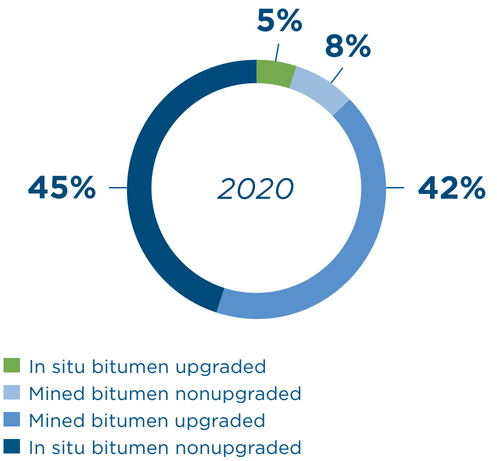


Figure 8 Alberta supply of crude oil and equivalent



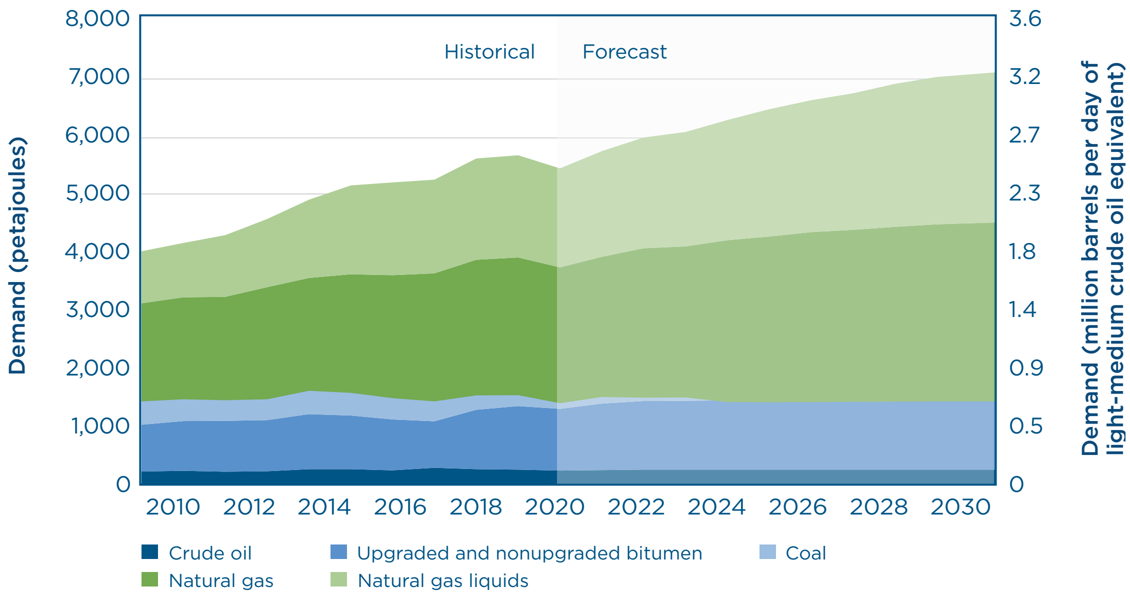
- Alberta's production of crude oil and equivalent decreased by 4 per cent in 2020, reaching 3.4 10^6 bbl/d. The decrease is largely attributed to the decline in the supply of upgraded and nonupgraded bitumen and crude oil.
- Production of crude oil and equivalent is expected to grow throughout the forecast period, reaching 4.6 10^6 bbl/d by 2030, driven primarily by growth in upgraded and nonupgraded bitumen production.
- Crude oil production decreased in 2020 to 0.4 10^6 bbl/d. As prices gradually improve throughout the forecast, production is projected to grow by 2024, then decline by 2030 as the number of new wells placed on production do not offset the decline in existing production.
- Pentanes plus production is forecast to grow from 0.3 10^6 bbl/d in 2020 to 0.5 10^6 bbl/d by 2030.
- In 2020, an estimated 47 per cent of produced raw bitumen was sent for upgrading in Alberta. By 2030, only about 40 per cent of bitumen is projected to be upgraded, as raw production is expected to outpace upgrading capacity additions.
- Upgraded bitumen output for 2020 was down 1 per cent. Production was down across most upgrading facilities, except at the CNRL Horizon site.

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



Total mined: 236.5 10^3 m^3/d.
Total in situ: 237.2 10^3 m^3/d.

Figure 10 Primary energy demand in Alberta



- Total primary energy demand within the province decreased by 4 per cent, to 5437 PJ (2.4 10^6 BOE/d) in 2020. Alberta demand is projected to increase to about 7074 PJ (3.2 10^6 BOE/d) by 2030. The largest increase is attributed to strengthening demand for pentanes plus as a diluent in bitumen blending. Increasing demand for natural gas will come from power generation (including coal-to-gas switching and cogeneration), and increasing production of bitumen. Alberta demand for bitumen is also forecast to increase with a recovery in overall energy demand and increased intake at the Sturgeon refinery.
- Power generation demand for coal in Alberta is anticipated to phase out 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 by 3 per cent in 2020, because of reduced oil removals due to lower oil production brought on by low oil prices. This is the second consecutive annual decline in primary energy removals over the past five years.
- Total primary energy removals from the province in 2020 were estimated at 9458 PJ (4.2 10^6 BOE/d), with oil (bitumen and crude oil) and natural gas liquids representing about 81 per cent of primary energy removals for the year.
- Removals from the province are projected to reach 11 689 PJ (5.2 10^6 BOE/d) by 2030, 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 increasing Alberta demand.
- Removals of marketable bituminous coal from Alberta increased by 2 per cent in 2020, reflecting continued marketing of higher value bituminous coal outside of Canada.
- In 2020, removals of crude oil, pentanes plus, upgraded bitumen, and nonupgraded bitumen were an estimated 506.6 thousand cubic metres per day (10^3 m^3/d) or 3.2 10^6 bbl/d. This is about 4 per cent lower than in 2019.
- By 2030, about 710.0 10^3 m^3/d (4.5 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 (pipeline and rail) to ship these volumes.

Figure 11 Primary energy removals from Alberta

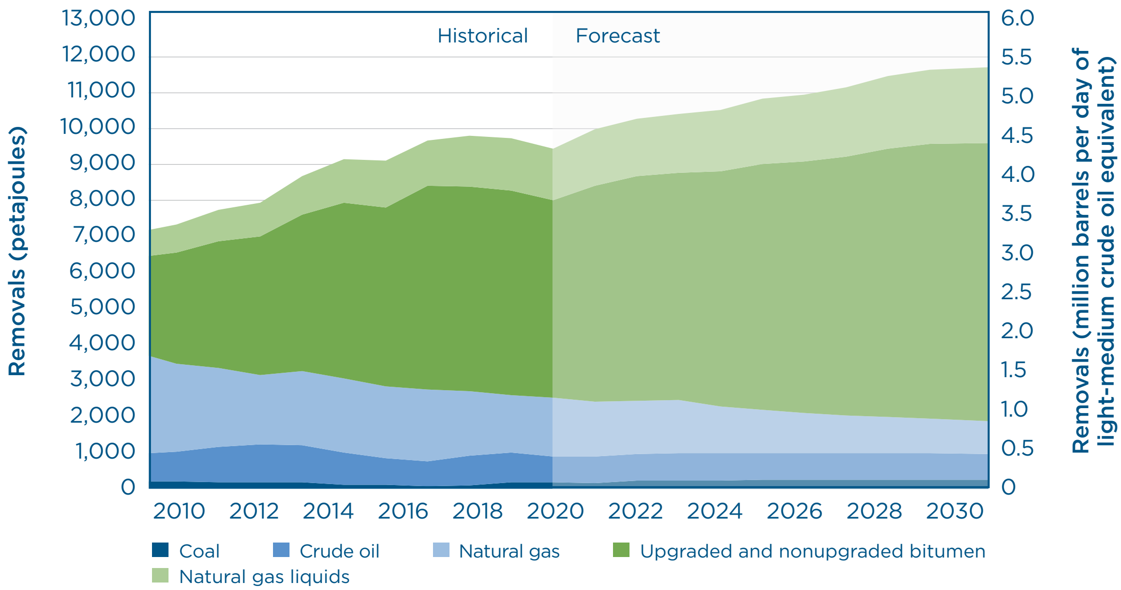


Figure 12 Total oil removals from Alberta

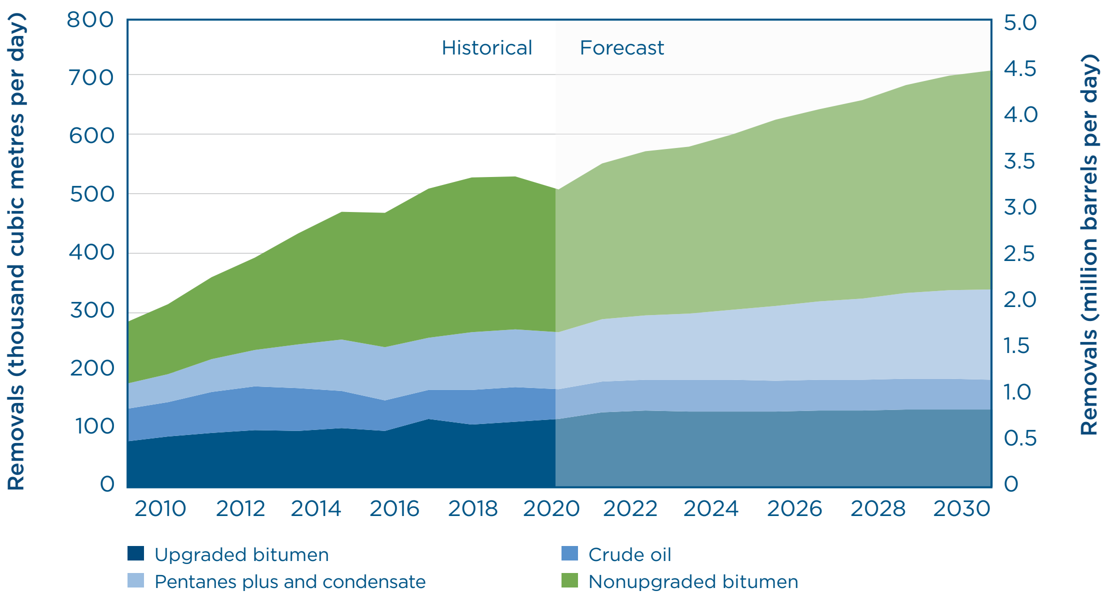
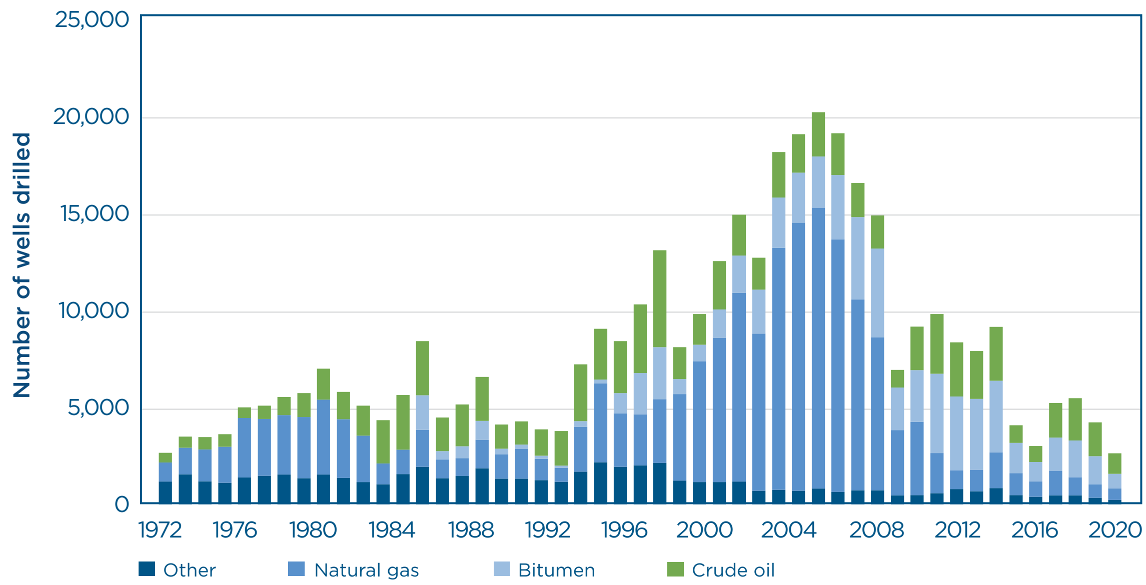


Figure 13 Historical drilling activity in Alberta



DRILLING ACTIVITY

- Total drilling decreased by 38 per cent in 2020 (natural gas drilling declined 13 per cent, crude oil drilling declined 39 per cent, and oil sands drilling declined 49 per cent). This is attributed to the low-price environment due to COVID-19 pandemic.

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