GOVERNMENT OF ALBERTA

Annual Report

Energy

2019-2020

Note to Readers:
Copies of the annual report are available on the Alberta Open Government Portal website www.alberta.ca

Energy
Communications
9945 108 Street NW
Edmonton, AB T5K 2G6

Phone: 780-427-8050
Email: info.energy@gov.ab.ca

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Acronyms and Notations

AER	Alberta Energy Regulator
AESO	Alberta Electric System Operator
AGS	Alberta Geological Survey
APMC	Alberta Petroleum Marketing Commission
ARP	Alberta Natural Gas Reference Price
AUC	Alberta Utilities Commission
bbl	Barrel
bbl/d	Barrels per day
Cdn$	Canadian Dollar
CEC	Canadian Energy Centre Limited
CFS	Clean Fuel Standard
COVID-19	Coronavirus 2019
ECCC	Environment and Climate Change Canada
ER&T	Emerging Resources and Technologies Initiative
ESG	Environmental Social Governance
FSEIS	Final Supplemental Environmental Impact Statement
GJ	Gigajoule
ha	Hectare
IDA	Integrated Decision Approach
IEEP	Incremental Ethane Extraction Program
IRMS	Integrated Resource Management System
KXL	Keystone XL
LAMAS	Land Automated Mineral Agreement System
LNG	Liquefied Natural Gas
MIM	Metallic and Industrial Minerals
MINRS	Metallic and Industrial Minerals Royalty Revenues
MSA	Market Surveillance Administrator
MW	Megawatt
NGAP	Natural Gas Advisory Panel
NGDDP	Natural Gas Deep Drilling Program
NGTL	TC Energy Corporation’s NOVA Gas Transmission Ltd.
NWRP	North West Redwater Partnership
OPEC	Organization of the Petroleum Exporting Countries
OWA	Orphan Well Association
PDP	Petrochemicals Diversification Program
PPA	Power Purchase Agreement
PUC	Public Utilities Commission
REP	Renewable Electricity Program
RRO	Regulated Rate Option
Tcf	Trillion cubic feet
TIER	Technology Innovation and Emissions Reduction
TSP	Temporary Service Protocol
US$	United States Dollar
WCS	Western Canadian Select
WTI	West Texas Intermediate

Preface

The Public Accounts of Alberta are prepared in accordance with the *Financial Administration Act* and the *Fiscal Planning and Transparency Act*. The Public Accounts consist of the annual report of the Government of Alberta and the annual reports of each of the 21 ministries.

The annual report of the Government of Alberta contains ministers' accountability statements, the consolidated financial statements of the province and the *Measuring Up* report, which compares actual performance results to desired results set out in the government's strategic plan.

This annual report of the Ministry of Energy contains the minister's accountability statement, the financial information of the ministry and a comparison of actual performance results to desired results set out in the ministry business plan. This ministry annual report also includes:

- **the financial statements of entities making up the ministry including the Alberta Energy Regulator, the Alberta Utilities Commission, the Alberta Petroleum Marketing Commission, the Post-closure Stewardship Fund, the Balancing Pool and the Canadian Energy Centre Limited for which the minister is responsible;**
- **other financial information as required by the** ***Financial Administration Act*** **and** ***Fiscal Planning and Transparency Act,*** **as separate reports, to the extent that the ministry has anything to report; and**
- **financial information relating to trust funds.**

Minister's Accountability Statement

The ministry's annual report for the year ended March 31, 2020, was prepared under my direction in accordance with the *Fiscal Planning and Transparency Act* and the government's accounting policies. All of the government's policy decisions as at July 14, 2020 with material economic or fiscal implications of which I am aware have been considered in the preparation of this report.

[Original signed by]

Honourable Minister Sonya Savage
Minister of Energy

Message from the Minister

There's no question that the COVID-19 pandemic has significantly altered the landscape of our province – and Alberta's energy sector. But, as we look back on 2019-20, prior to the peak of the public health emergency, it's important to remember the significant strides our government has taken to defend and support this vital industry. We can't lose sight of these successes, as, in the months and years to come, we plan to resume this momentum as we implement our *Blueprint for Economic Recovery.*

Throughout the year, acting on the input and recommendations of Albertans and industry experts, we took numerous steps to build on the strengths of our world-class natural resources and increase investor confidence in our energy sector.

We provided industry with royalty certainty through the *Royalty Guarantee Act*. We announced that Alberta will maintain its cost-effective, reliable energy-only market, bringing certainty and private sector investment back to the province. And, we conducted a thorough review of the Alberta Energy Regulator – resulting in actions to strengthen its governance and reduce unnecessary delays – to ensure the province's resources are being developed efficiently and in an environmentally responsible manner.

That is also why we extended our loan to the Orphan Well Association by up to $100 million. The loan bolsters the association's reclamation efforts while staying to true to our province's reputation as a responsible energy producer and creating jobs for Albertans.

Led by Associate Minister of Natural Gas and Electricity Dale Nally, we have made significant progress in helping to revitalize the natural gas sector. We worked with Municipal Affairs to implement a 35 per cent property assessment reduction for Alberta's shallow gas producers for the 2019 tax year, which has been extended into 2020 to allow for new assessment models to be implemented. We also facilitated an industry-led solution to help producers access previously unavailable storage, creating more balance on our pipelines and reducing price volatility. We continue to work with our industry partners, municipalities and Indigenous communities to help set a long-term vision for the sector.

Our work to cut red tape – and the resulting regulatory burden – also continued. We completed wide-ranging reduction initiatives to simplify reporting and reduce approval timelines. We also engaged industry to help identify further reductions and have directed our agencies, boards and commissions to reduce red tape, as well. We've accomplished a lot in this area, but much more is on the horizon.

As we move through the 2020-21 fiscal year, our government remains committed to supporting the energy sector and the businesses that support it. This is especially important as our province faces a daunting challenge: the triple threat of the COVID-19 pandemic, the resulting worldwide recession and the commodity price crisis.

When the pandemic reached Alberta, our first priority was to support those in need. We implemented the Utility Payment Deferral Program, which successfully supported Albertans through the three peak months of the pandemic.

On the economic front, I strongly believe Alberta is well-prepared to deal with the challenges ahead.

As a result of several years of transportation bottlenecks and landlocked oil sands reserves, we had already been updating our provincial energy strategy. While we cannot underestimate the mammoth challenge ahead, this early planning has provided us with a solid foundation for recovery.

Our swift response to the pandemic will ensure Alberta is prepared to meet the demands of the post-COVID world.

This was quickly followed by actions to set our province up for long-term prosperity. Our investment in Keystone XL and sustained advocacy for further market access will play a key part.

Our *Blueprint for Economic Recovery* will build on these actions and solidify the future of our largest industry, while placing a strong emphasis on supporting diversification. Every credible forecast of future world energy consumption sees oil and gas continuing to dominate the supply mix for the next several decades. So, we will continue to vigorously advocate on behalf of the hundreds of thousands of workers whose livelihoods depend on it.

At the same time, we are setting an unprecedented path toward a new, innovative and diversified energy future, recognizing the development of new sustainable forms of energy will increasingly become a driver of investment moving forward.

These efforts include finalizing a new value-added natural gas strategy and a petrochemical program, as well as leveraging Alberta's natural geological advantages through the development of a new mineral strategy and increasing investment in new emerging areas such as geothermal energy.

Meanwhile, we will continue to be guided by our high environmental, social and governance (ESG) standards. Canada, led by Alberta, ranks third in global ESG factors – and we will maintain our leadership on this front. As we move forward, we will emphasize that Alberta is the logical choice to meet global energy demands.

While it has not been business as usual, the pandemic has only strengthened our resolve. We have overcome trying times in our past and we will do so again. Albertans are highly educated, hardworking, and are known for their pioneering spirit – a spirit that was on display when the oil sands were developed and will continue as our energy sector continues to evolve.

We remain very confident that Alberta will play a prominent role in meeting post-pandemic future demand.

[Original signed by]

Honourable Minister Sonya Savage
Minister of Energy

Management's Responsibility for Reporting

The Ministry of Energy includes:

- Department of Energy,
- Alberta Energy Regulator,
- Alberta Utilities Commission,
- Alberta Petroleum Marketing Commission,
- Post-closure Stewardship Fund,
- Balancing Pool, and
- Canadian Energy Centre Ltd.

The executives of the individual entities within the ministry have the primary responsibility and accountability for the respective entities. Collectively, the executives ensure the ministry complies with all relevant legislation, regulations and policies.

Ministry business plans, annual reports, performance results and the supporting management information are integral to the government's fiscal and strategic plan, annual report, quarterly reports and other financial and performance reporting.

Responsibility for the integrity and objectivity of the accompanying ministry financial information and performance results for the ministry rests with the Minister of Energy. Under the direction of the Minister, as senior executives, we oversee the preparation of the ministry's annual report, including the financial information and performance results. The financial information and performance results, of necessity, include amounts that are based on estimates and judgments. The financial information is prepared using the government's stated accounting policies, which are based on Canadian public sector accounting standards. The performance measures are prepared in accordance with the following criteria:

- **Reliability** – Information used in applying performance measure methodologies agrees with the underlying source data for the current and prior years' results.
- **Understandability** – the performance measure methodologies and results are presented clearly.
- **Comparability** – the methodologies for performance measure preparation are applied consistently for the current and prior years' results.
- **Completeness** – outcomes, performance measures and related targets match those included in the ministry's *Budget 2019*.

As senior executives, in addition to program responsibilities, we are responsible for the ministry's financial administration and reporting functions. The ministry maintains systems of financial management and internal control which give consideration to costs, benefits, and risks that are designed to:

- provide reasonable assurance that transactions are properly authorized, executed in accordance with prescribed legislation and regulations, and properly recorded so as to maintain accountability of public money;
- provide information to manage and report on performance;
- safeguard the assets and properties of the province under ministry administration;

- provide Executive Council, the President of Treasury Board, Minister of Finance, and the Minister of Energy the information needed to fulfill their responsibilities; and
- facilitate preparation of ministry business plans and annual reports required under the *Fiscal Planning and Transparency Act.*

In fulfilling our responsibilities for the ministry, we have relied, as necessary, on the executives of the individual entities within the ministry.

[original signed by]

Grant Sprague, Q.C.
Deputy Minister of Energy

Adrian Begley
Chief Executive Officer
Alberta Petroleum Marketing Commission

Carolyn Dahl Rees
Chair
Alberta Utilities Commission

Laurie Pushor
President and Chief Executive Officer
Alberta Energy Regulator

Tom Olsen
Chief Executive Officer and Managing Director
Canadian Energy Centre Ltd.

Greg Clark
Chair
Balancing Pool

July 14, 2020

Results Analysis

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Ministry Overview

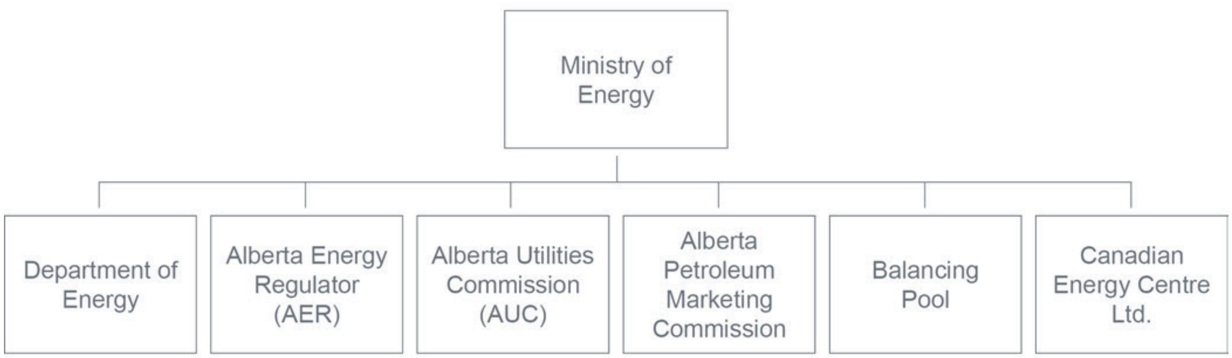
The Ministry of Energy manages Alberta's energy and mineral resources to ensure they are developed responsibly, in a way that benefits and brings value to Albertans. The ministry strives to ensure sustained prosperity in the interests of Albertans through the stewardship of energy and mineral resources. This includes having high regard for the social, economic and environmental impacts of Alberta's energy development.

The ministry consists of the Department of Energy, the Alberta Energy Regulator, the Alberta Utilities Commission, the Alberta Petroleum Marketing Commission, the Balancing Pool and the Canadian Energy Centre. Each entity plays an important role in overseeing the orderly development of Alberta's energy and mineral resources.

The outcomes in Energy's 2019-23 Business Plan are:

- **Outcome One:** Albertans benefit economically from investment in responsible energy and mineral development and access to global markets
- **Outcome Two:** Effective, efficient stewardship and regulation of Alberta's energy and mineral resources.

Organizational Structure



Note: The Post Closure Stewardship Fund is a regulated fund that is administered by the department

Department of Energy

- Acts as the steward of Alberta's energy and mineral resources on behalf of all Albertans
- Develops and administers policies and programs to guide the management and development of Alberta's non-renewable resources, including conventional and unconventional oil and gas, oil sands, coal, metallic and industrial minerals, and petrochemicals
- Ensures the integration of energy and mineral policies and serves as an interface between policy development and policy assurance
- Grants industry rights to explore and develop Alberta's Crown-owned energy and mineral resources
- Establishes, administers and monitors the effectiveness of Alberta's royalty systems for Crown-owned energy and mineral resources
- Collects revenues from the development of Alberta's energy and mineral resources on behalf of Albertans
- Establishes the framework for responsible industry-led investment in electricity infrastructure and markets for the reliable delivery of electricity to consumers

- Leads Alberta's market access efforts with internal, external and international stakeholders
- Administers the carbon capture and storage Post-closure Stewardship Fund

Alberta Energy Regulator

- Independently makes regulatory decisions regarding upstream petroleum, natural gas, bitumen and coal development in accordance with applicable legislation and regulations and within the framework of Alberta's overall energy policy
- Responds to changes in the energy industry while providing regulatory certainty for investors and the public, including assurance that risks are appropriately mitigated throughout the lifecycle of energy projects
- Provides for the safe, efficient, orderly, and environmentally responsible development of energy resources
- Provides geoscience information, evaluation and advice about the geology of Alberta that is used to support the exploration, resource appraisal, sustainable development, regulation, and conservation of Alberta's resources through the Alberta Geological Survey

Alberta Utilities Commission

- Regulates investor-owned electric, natural gas and water utilities, and certain municipally-owned electricity utilities to ensure customers receive safe and reliable utility service at just and reasonable rates
- Independently makes decisions on the need, siting, construction, alteration, operation and decommissioning of natural gas distribution and certain electricity transmission facilities
- Regulates power plants in a similar fashion, except the need for new power plants which is determined by market forces
- Develops and amends rules that support the orderly operation of the retail natural gas and electricity markets, and adjudicates on market and operational rule contraventions that the Market Surveillance Administrator may bring before the Alberta Utilities Commission
- Ensures that the delivery of Alberta's utility services takes place in a manner that is fair, responsible and in the public interest

Alberta Petroleum Marketing Commission

- Markets the Crown's conventional crude oil royalty barrels received in lieu of cash royalties
- Determines prices used in the valuation of the Crown's royalty share of natural gas, natural gas liquids, and sulphur
- Assists with the development of new energy markets and transportation infrastructure
- Responsible for the stewardship of the Sturgeon Refinery processing agreement and other commercial contracts
- Evaluates strategic proposals for adding value to Alberta's resources

Balancing Pool

- Acts as a risk backstop in relation to extraordinary events such as force majeure

- Acts as a buyer for the Power Purchase Arrangements (PPAs) that were not sold in the public auction held by the Government of Alberta in 2000 or that have subsequently been terminated by third party buyers, and manages the resulting electricity portfolio and/or where feasible terminates the PPAs with the owners
- Allocates or collects any forecast cash surplus or deficit to and from electricity consumers in Alberta in annual amounts over the life of the Balancing Pool
- Holds the Hydro Power Purchase Arrangement and manages the associated stream of receipts or payments
- Participates in regulatory and dispute resolution processes

Canadian Energy Centre Limited

- Responds to misinformation about Canadian oil and natural gas
- Creates original content to elevate the general understanding of Canada's energy sector to help the country take control of its energy story
- Centralizes and analyses data that targets investors, researchers and policy makers

Alberta's Energy Resource Sector

Non-Renewable Resource Revenue

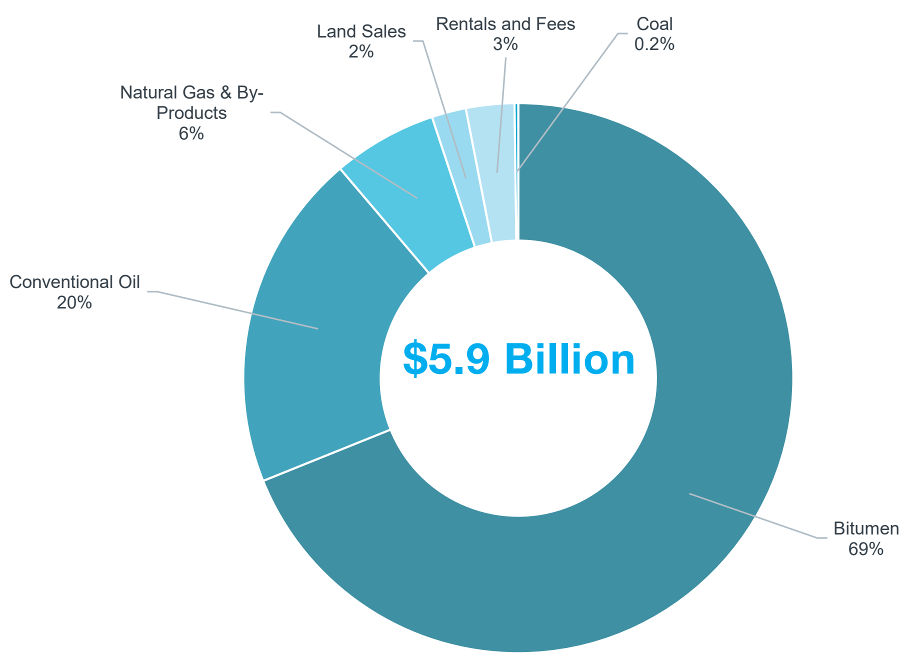
Energy development in Alberta is a key provider of investment, jobs, business opportunities, taxes and royalty revenues that fund important government programs for Albertans. Energy development also drives activity in a number of other industries, including construction and manufacturing, which benefit communities across Alberta and Canada.

Non-Renewable Resource Revenue Generated

The department is responsible for collecting non-renewable resource revenue on behalf of Albertans. Royalties are payments to Albertans for Crown-owned resources that are produced and sold. Albertans, as owners, collect value from our resources through royalties, bonuses and lease rentals.

Developing Alberta's resources requires a working relationship between the province and energy companies. The price received and the costs involved in producing and selling those resources affect the value available for royalties. Non-renewable resource revenues totaled $5.9 billion in the 2019-20 fiscal year, about $600 million lower than the budgeted amount of $6.5 billion.

2019-20 Non-Renewable Resource Revenue



Source: Government of Alberta

Note: Totals may not add up precisely due to rounding.

Non-Renewable Resource Revenue Forecasting

Treasury Board and Finance is responsible for forecasting non-renewable resource revenue.

Non-renewable revenue forecasts are based on economic conditions at the time of the forecast, anticipated economic growth, non-renewable resource demand trends and expected supply levels. Commonly, the most influential factor affecting non-renewable resource revenue is commodity prices. Other factors such as capital and operating costs, the U.S. - Canadian dollar exchange rate and production also affect royalty revenues. Unanticipated changes in these factors could result in significant differences between the budget forecast and the actual results.

The Government of Alberta models the complex system to calculate royalties and forecast non-renewable resource revenue. To develop price forecasts, the government considers in its analysis a number of industry consultants and the futures market as well as a deep analysis of global, North American and Alberta market fundamentals.

The non-renewable resource revenue forecast can change frequently throughout the year as new price, cost and production forecasts are issued. When the market is changing rapidly, price outlooks are frequently updated and the government incorporates recent market trends to reflect those rapid developments in a timely manner. Changes in production forecasts and other variables such as industry costs and investments are also incorporated into each quarterly update.

Commodity Prices and Trends[i]

Commodity Prices	2019-20 Budget	2019-20 Actual
WTI (US$/bbl)	57.00	54.84
Exchange rate	0.75	0.75
Light-heavy differential (US$/bbl)	14.20	14.82
WCS (US$/bbl)	42.80	40.03
Alberta natural gas reference price (Cdn$/GJ)	1.30	1.39

Sources: Government of Alberta; U.S. Energy Information Administration

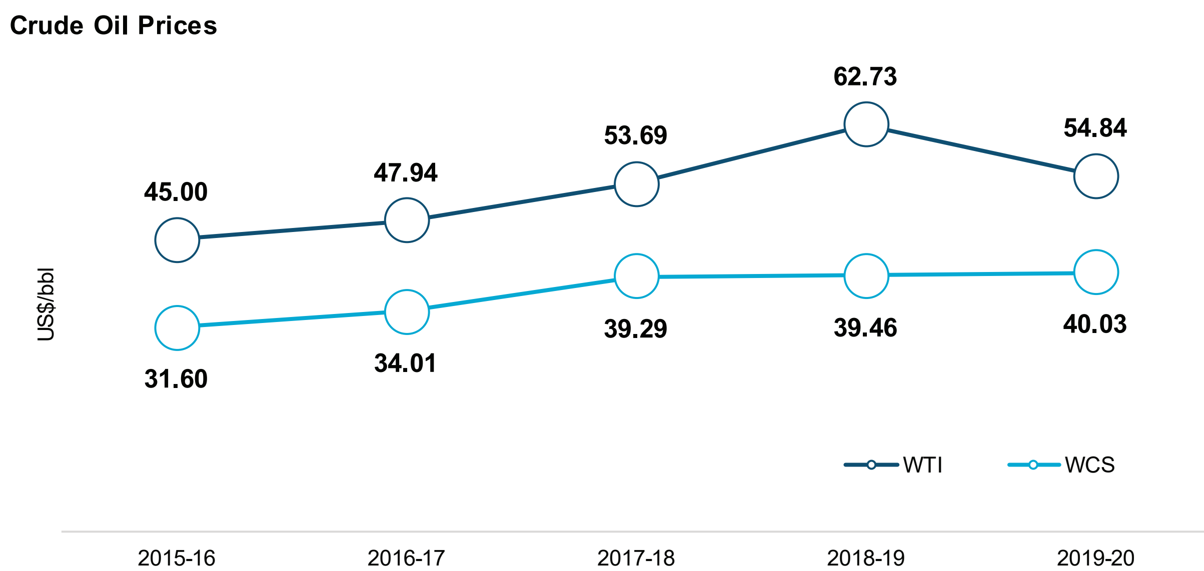
Oil Prices

The oil price difference is affected by differences in crude quality between light sweet and heavy sour oils, location, market demand, and by access to markets for these products. Alberta is landlocked and exports both light and heavy crude oil. However, the majority of Alberta's oil production growth and oil exports is from heavy crude, for which price per barrel is discounted from light sweet prices.

West Texas Intermediate (WTI) is the North American price benchmark for light sweet oil. Western Canadian Select (WCS) is a North American price benchmark for heavy crude oil, commonly used to price Canadian heavy oil.

The WTI price averaged almost US$93.00 per barrel in the four fiscal years from 2010-11 to 2013-14, but then declined by approximately 70 per cent from about US$105.00 per barrel in June 2014 to around US$30.00 per barrel in February 2016. The decline in WTI price was due to a combination of factors, including global supply growth exceeding demand growth, with supply boosted by significant increases including those from North American production; continuing increases in global inventories; and demand muted by a slowdown in developing economies. WTI prices increased from US$45.00 per barrel in 2015-16 to US$47.94 per barrel in 2016-17, as the Organization of the Petroleum Exporting Countries (OPEC) members and some non-OPEC producers agreed, in late 2016, to reduce output by 1.8 million barrels per day, commencing in 2017. Following the momentum that started in the second half of 2017, WTI prices increased to US$53.69 per barrel in 2017-18 and further increased to US$62.73 per barrel in 2018-19.

[i] Note: WCS data is reported in Canadian currency in the Government of Alberta budget documents. To allow for comparisons with other price data in this annual report, WCS has been converted to U.S. currency. Conversions may differ slightly, depending on the treatment of exchange rates.

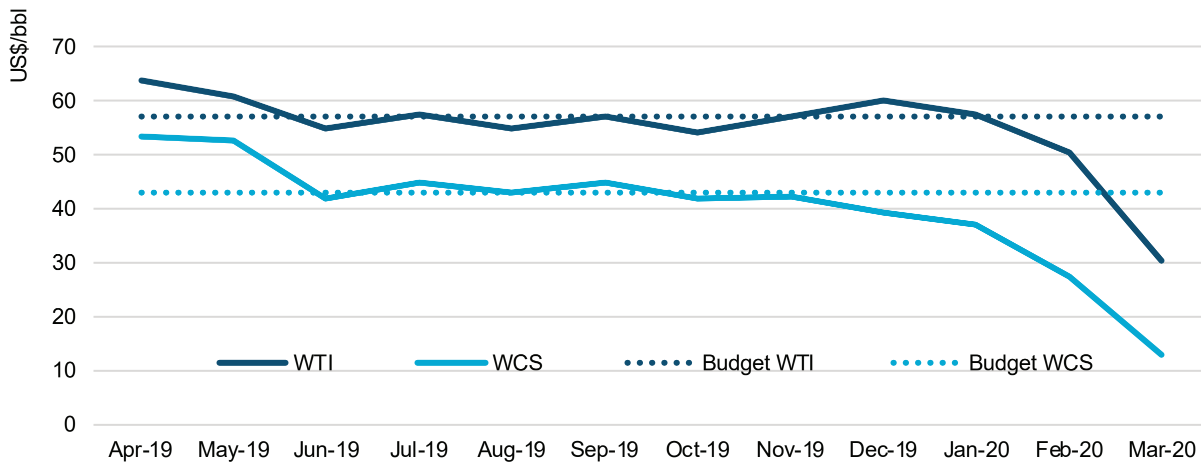


Source: Alberta Ministry of Energy

Budget 2019 was based on an estimate of US$57.00 per barrel price for WTI crude oil and an exchange rate of 75 cents U.S. to the Canadian dollar in 2019-20. The actual WTI price averaged US$54.84 per barrel in 2019-20. WTI prices decreased in 2019-20 compared to the previous fiscal year as risks of global economic weakening outweighed heightened geopolitical risks. The COVID-19 outbreak in the fourth quarter of 2019-20 also affected the global crude oil demand, and contributed to the reduction of oil prices. In December 2019, the agreement, between OPEC and some non-OPEC producers, to cut production was extended until March 2020. Saudi Arabia and Russia became engaged in a price war in late March 2020 before reaching an agreement with other OPEC and some non-OPEC crude oil producers on April 12, 2020. The price war led to a strong decrease in WTI prices. The production cut agreement is scheduled to be in place until April 2022. Most analysts are forecasting that WTI prices will be depressed in the short term due to the impact of COVID-19 on global crude oil demand and high global crude inventory.

The WCS price was estimated at US$42.80 per barrel for 2019-20 in Budget 2019. The WCS price saw a considerable decline from an average of almost US$73 per barrel during the 2010-11 to 2013-14 fiscal year period to US$31.60 per barrel in 2015-16. Since then, the WCS price experienced some recovery, averaging US$34.01 per barrel in 2016-17 and US$39.29 per barrel in 2017-18. The supply growth in Western Canada, constrained take-away capacity, and the deep U.S. Midwest refinery turnaround season in 2018 resulted in wider light-heavy differentials in late 2018. The decline in international crude oil prices close to the end of 2018 also pushed the WCS prices to historical lows. WCS prices started to recover in early 2019 with improving international oil prices and Government of Alberta's curtailment policy. The WCS price received an additional uplift from both the Alberta crude oil curtailment and continued reduction in Venezuelan heavy oil supply due to the U.S. sanctions. The actual WCS price averaged US$40.03 per barrel in 2019-20, slightly lower than the budgeted price, mainly due to global crude oil prices that were lower than the prices anticipated in Budget 2019.

2019-20 Crude Oil Prices



Soucrce: U.S. Energy Information Administration; Ministry of Energy

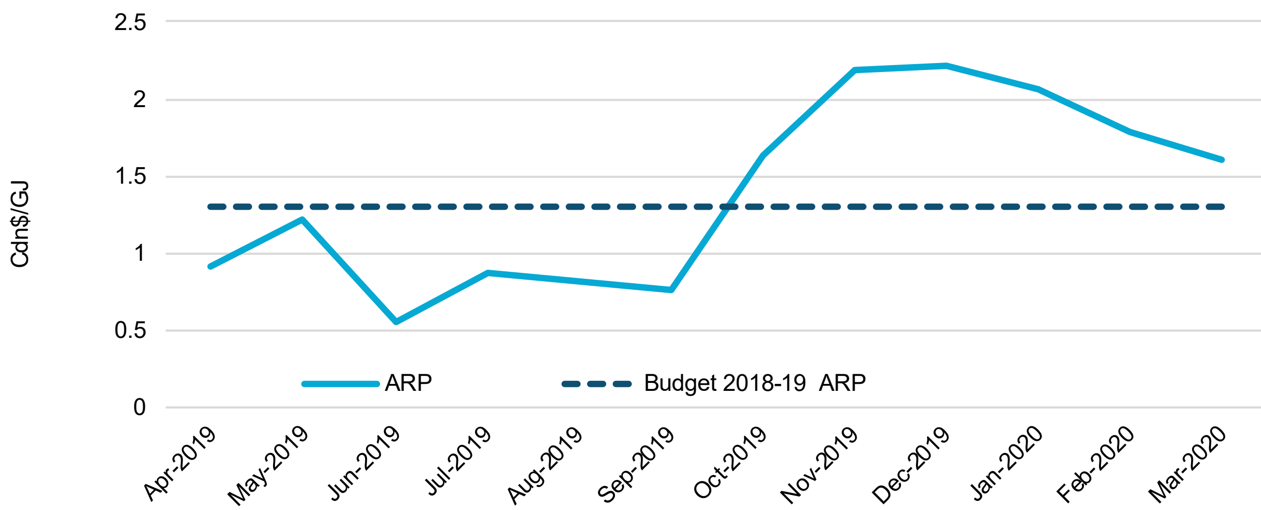
Natural Gas Prices

The Alberta Natural Gas Reference Price (ARP) is used in natural gas royalty formulas for natural gas royalty revenue calculation.

Overall, the general rule of supply and demand balance determines natural gas prices in North America. Storage levels and weather patterns affect prices as these factors impact the market's ability to respond to additional demand. Lower storage levels could lead to higher prices and vice-versa. Lower than normal temperatures in the winter and higher than normal temperatures in the summer could lead to increased demand and higher prices.

Royalties in Budget 2019 were based on a gas price forecast of ARP at Cdn$1.30/gigajoule (GJ). The realized ARP averaged Cdn$1.39/GJ in the fiscal year 2019-20. The actual gas price was above budgeted levels at the end of the fiscal year due to a combination of Canadian production drop, winter heating demand, low storage inventory level and strong storage injection demand. Furthermore, TC Energy Corporation's Temporary Service Protocol (TSP) improved access to storage on its Nova Gas Transmission Ltd. (NGTL) pipeline system during planned summer maintenance periods in Western Canada.

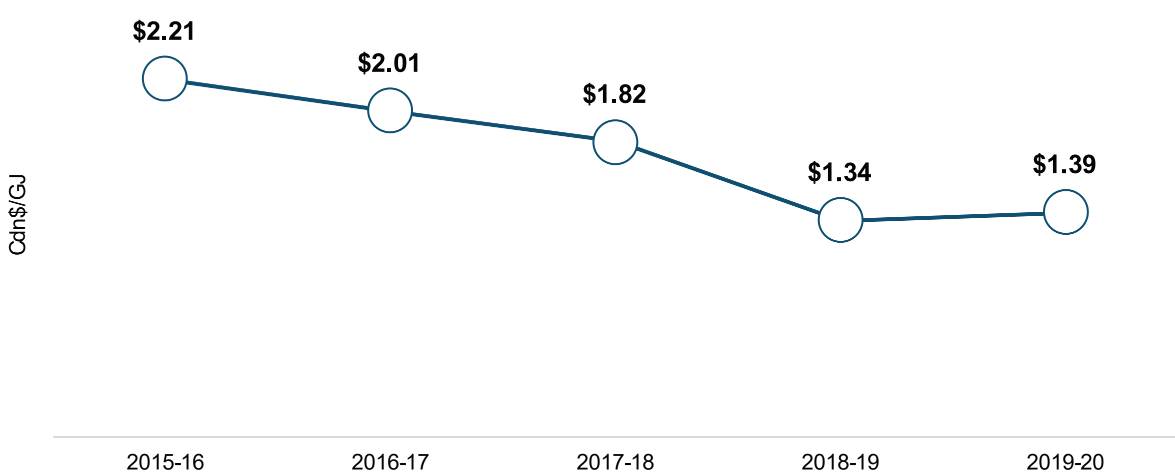
2019-20 Alberta Gas Reference Price



Source: Government of Alberta

Although other North American benchmark natural gas prices declined gradually year-over-year throughout 2019, AECO prices were particularly weak and volatile prior to the implementation of the TSP in October 2019. This was mainly due to robust U.S. and Canadian production, as well as infrastructure issues combined with restriction protocol during summer maintenance periods when natural gas demand was low on TC Energy Corporation's NGTL pipeline system in Western Canada. The combined impact led AECO prices to be heavily discounted and volatile to other North American benchmark prices in the summer and fall of 2018.

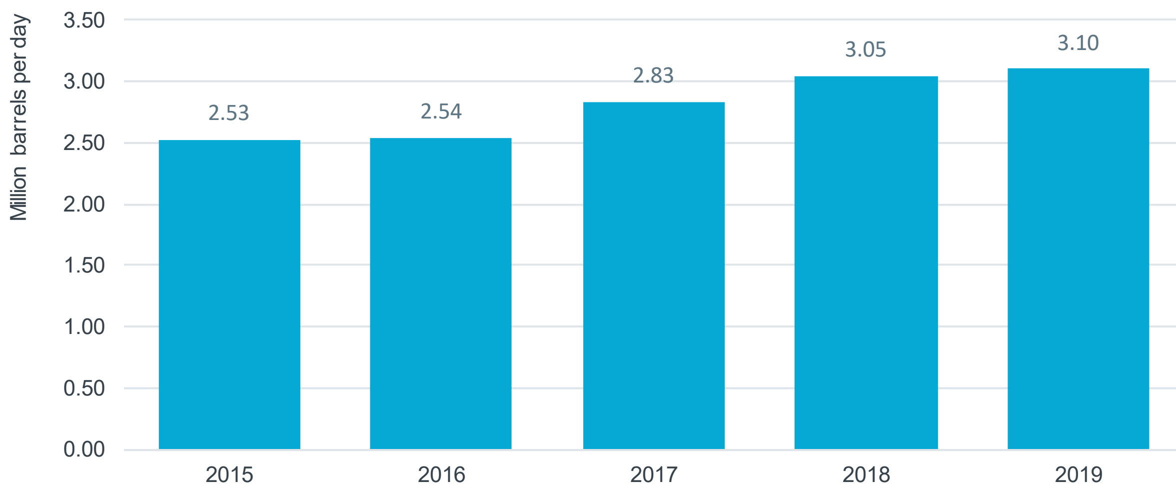
Alberta Gas Reference Price



Source: Government of Alberta

Production: Performance Indicator 1.b[i]

Alberta Crude Bitumen Production



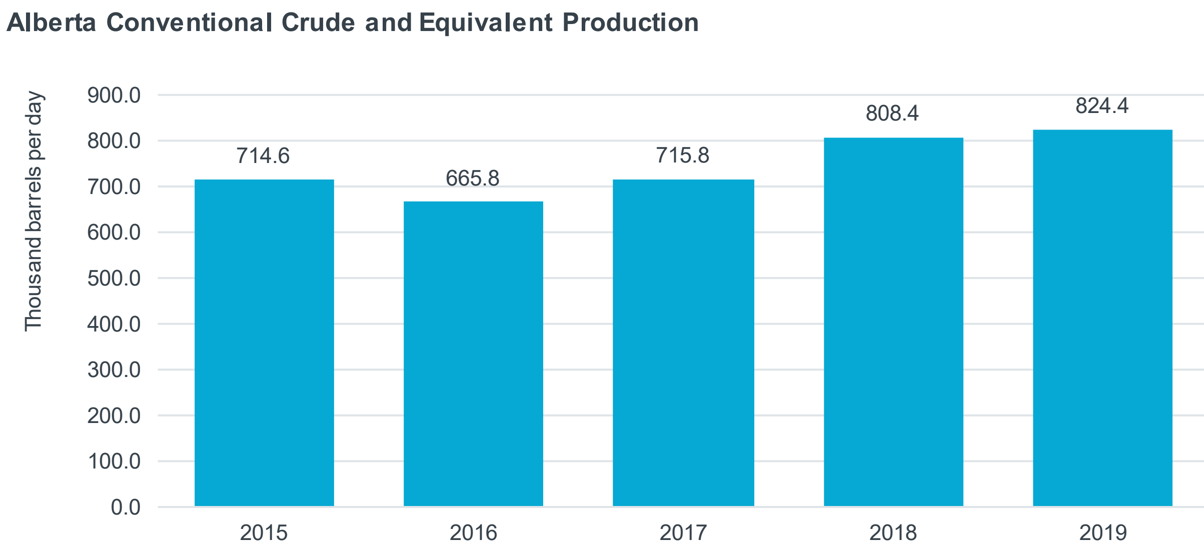
Source: Alberta Energy Regulator

Crude bitumen production, which consists of mined and in-situ production, increased by about 1.8 per cent from 3.05 million barrels per day in 2018 to 3.10 million barrels per day in 2019. This was significantly smaller than the year-over-year increase of 7.5 per cent in bitumen production that took place from 2017 to 2018. Overall, the significant slowdown in Alberta's bitumen production rate of growth from 2017-18 to 2018-19 was due to the lack of advancement in additional egress. Pipelines and rail did increase by 71,000 barrels per day through 2019 as a result of debottlenecking projects and additional rail contracts; however, this was still not sufficient for meeting Alberta's market access requirements. The Government of Alberta's curtailment policy aligned to these increases to ensure that Alberta's production and storage were managed throughout 2019.

During 2019, total mined production increased by 5.4 per cent to 1.55 million barrels per day, due to increases in production from Suncor Energy's and Syncrude's mines, while total in-situ production decreased by 1.6 per cent to 1.55 million barrels per day.

The share of crude bitumen production as a percentage of global consumption remained at about 3.1 per cent in 2019. Alberta accounts for 100 per cent of Canadian crude bitumen production.

[i] Note: commentary in this section provides more detail on Alberta's oil and gas production profile than is included in the Performance Indicator. Discussion, specific to the indicator is included among other statistics and commentary on oil and gas production in Alberta. Further information on sources and methodoloy for this performance indicator can be found in the Performance Measure and Indicator Methodology section on page 81.



Source: Alberta Energy Regulator

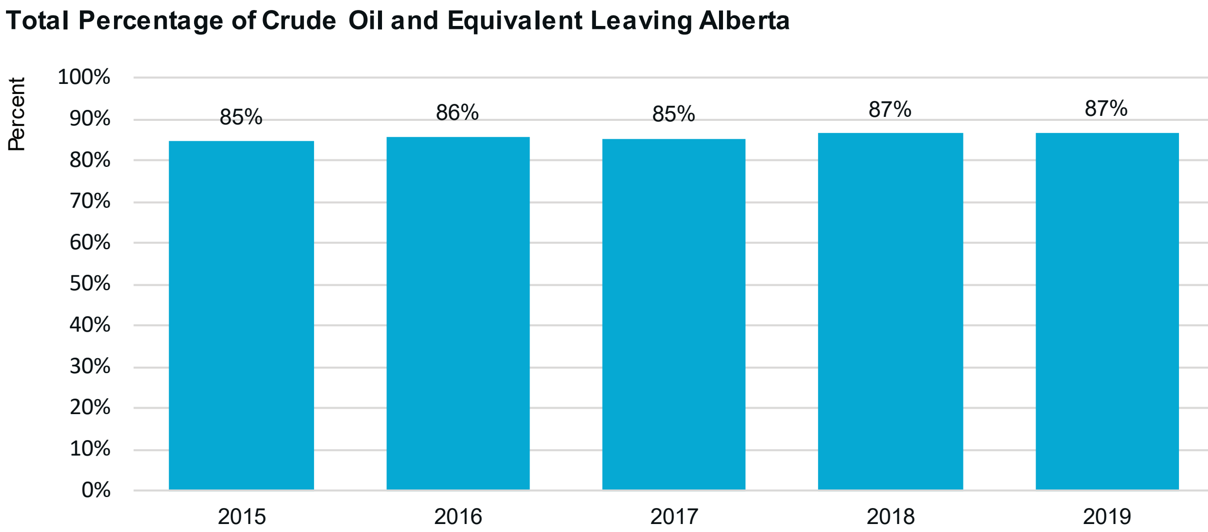
Production of crude oil and equivalent (condensate and pentanes plus) increased by about two per cent, from about 808,400 barrels per day in 2018 to about 824,400 barrels per day in 2019.

Conventional production decreased by about 0.5 per cent from 2018 to 2019, from about 489,600 barrels per day to 487,300 barrels per day. Significant reductions in drilling activity due to market access and policy uncertainty, along with conservative capital spending programs, led to a year-over-year decrease in production. The increase in condensate and pentanes plus production continued in 2019; the production went up by about six per cent from 318,800 barrels per day in 2018 to about 337,000 barrels per day in 2019 as producers continued to focus on production in low permeability areas with large volumes of light crude oil, such as the Montney and Duvernay due to price premium on light oil.

Alberta Oil Production in the Canadian Context

Alberta accounts for a significant majority of Canada's crude oil and equivalent production. According to the Canada Energy Regulator, in 2019, total Alberta crude oil and equivalent production, which consists of conventional crude production, non-upgraded and upgraded bitumen, and condensate and pentanes plus accounted for 80.5 per cent of total Canadian production. This represented a slight decline from the 2018 share of 81.1 per cent of Canadian production. Over the 2015-2019 period, Alberta's share of Canadian production was generally consistent at around 80 per cent, ranging from 79.8 per cent in 2016 to 81.1 per cent in 2018.

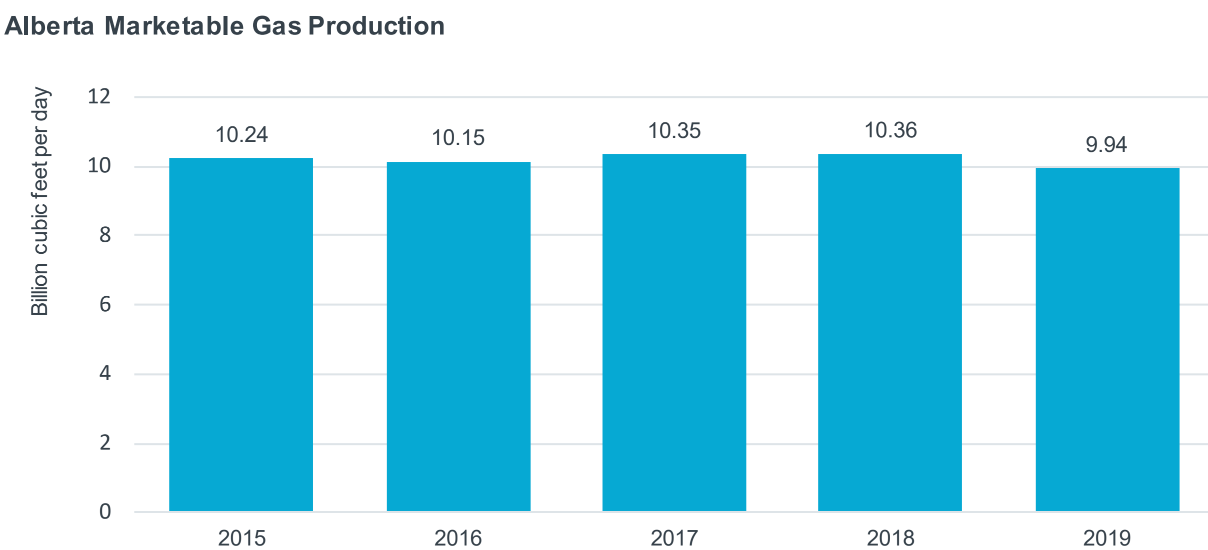
Disposition of Alberta Oil



Source: Alberta Energy Regulator

The significant majority of Alberta oil disposition goes to the United States and other Canadian jurisdictions. In 2019, about 87 per cent of Alberta's total crude oil and equivalent disposition, virtually the same share as in 2018, left the province.

Natural Gas Production



Source: Alberta Energy Regulator

From 2018 to 2019, marketable natural gas production declined approximately four per cent, with a 0.42 billion cubic feet per day reduction from 10.36 billion cubic feet per day in 2018 to 9.94 billion cubic feet per day in 2019. The production decline was mainly due to the combined impact of low and volatile AECO price and regional pipeline infrastructure bottlenecks in Western Canada. Natural gas production has been resilient due to increased drilling for natural gas liquids due to demand for condensate. Natural gas production from liquids-rich areas is forecast to continue to account for more than half of the natural gas production in the province. Overall, total natural gas liquids production increased five per cent in 2019 over 2018. Condensate is used as diluent that is blended with non-upgraded bitumen and heavy crude oil to meet pipeline specifications for transportation. The demand for condensate in 2019 exceeded the demand in 2018.

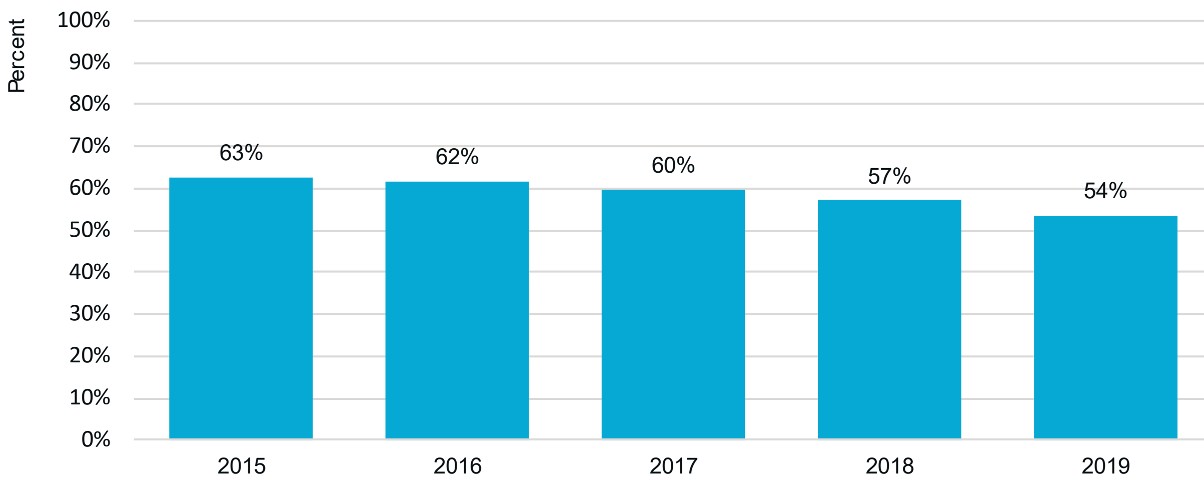
Alberta Natural Gas Production in the Canadian Context

Alberta accounts for a majority of Canada's marketable natural gas production. In 2019, according to the Canada Energy Regulator, Alberta accounted for 64.7 per cent of total Canadian production. This represented a slight decline from 65.2 per cent in 2018. Over the 2015-2019 period, Alberta accounted for approximately two thirds of Canadian production, ranging from 64.7 per cent in 2019 to 67.9 per cent in 2017.

Disposition of Alberta Gas

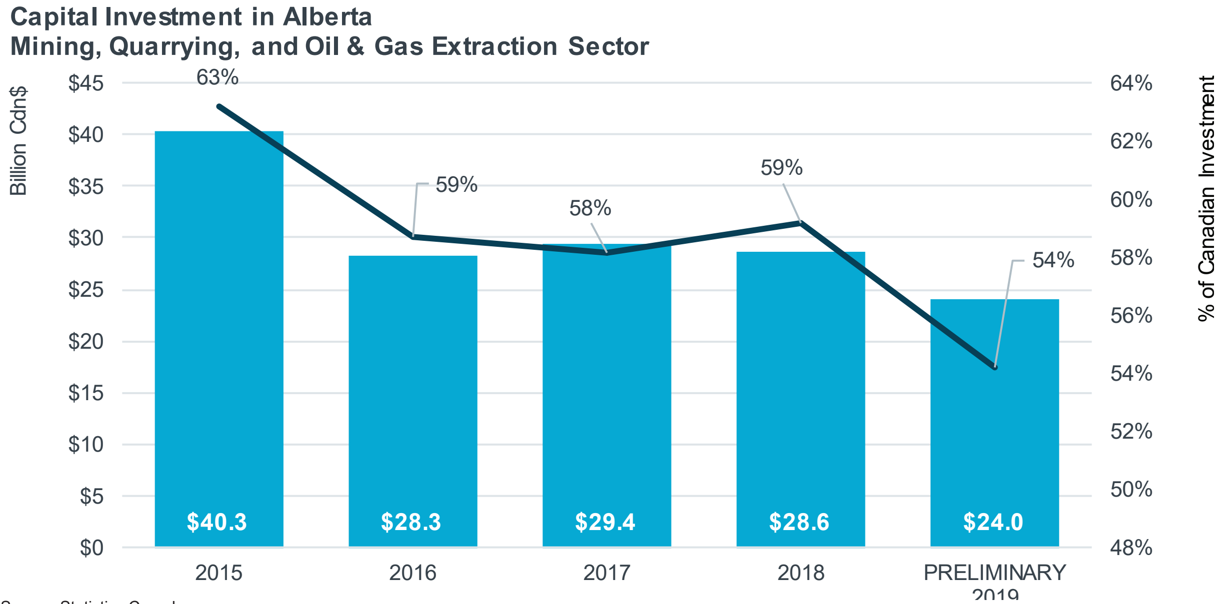
In 2019, a majority of Alberta's total gas disposition, or 54 per cent, was exported to the rest of Canada (22 per cent) and the United States (32 per cent). However, over the 2015 – 2019 period, the share of gas disposition leaving the province experienced a decline. In 2015, about 37 per cent of Alberta gas disposition remained in Alberta. This share went up to 46 per cent in 2019.

Total Percentage of Gas Leaving Alberta



Source: Alberta Energy Regulator

Investment: Performance Indicator 1.c[i]



Source: Statistics Canada

The chart above, with the data for the 2015-2019 period, demonstrates the importance of Alberta's energy industry investment within the Canadian context.

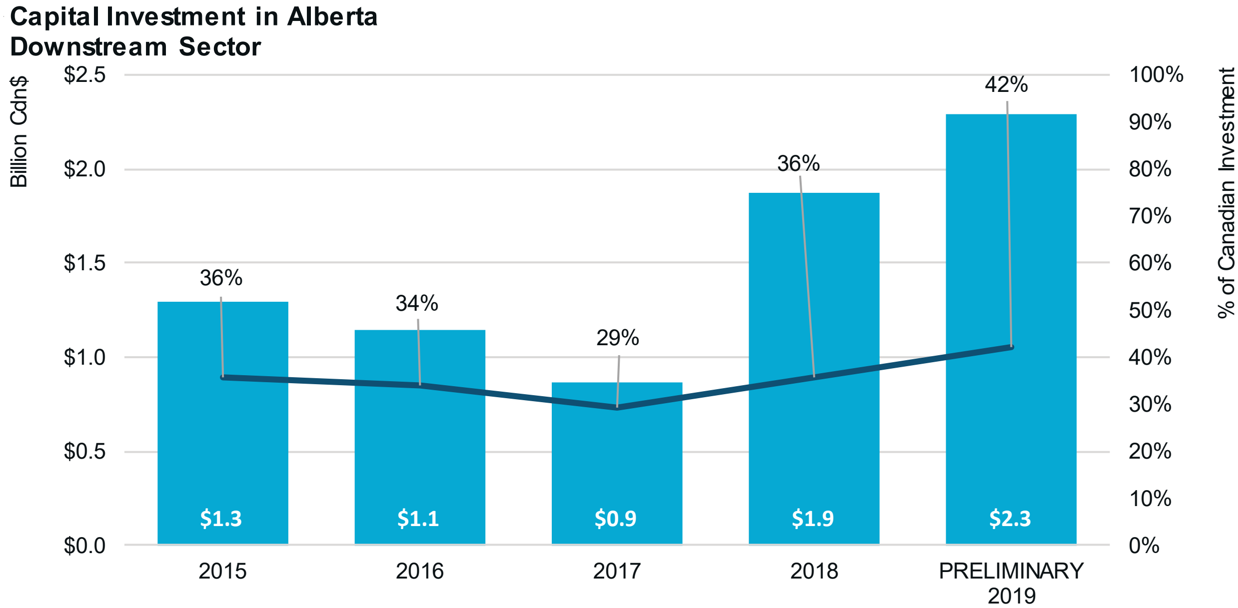
Upstream energy investment in Alberta consists of mining, quarrying, conventional oil and gas investment, oil sands investment, as well as support activities. Alberta has to compete for investment with other oil and gas producing jurisdictions to ensure continuous development of its energy industry. This has been more of a challenge following the significant decline in oil prices that took place in late 2014. The oil price decline in late 2014 did not prevent the total mining, quarrying, and oil and gas extraction sector investment in Alberta, in 2014, from setting an all-time Alberta record at $61 billion. However, the price decline has impacted the industry since that time, as investment in the sector has remained below 2014 levels in the years since.

The 2018 results that are reported in the present Annual Report have been revised from the preliminary 2018 actuals reported in the 2018-19 Annual Report to reflect actual results released by Statistics Canada. The upstream energy industry investment in Alberta for 2018 was $28.6 billion, accounting for 59 per cent of Canadian upstream investment; these results supersede the preliminary actual results that were reported in the 2018-19 Annual Report.

If the 2019 preliminary actual result of $24.0 billion materializes, investment in Alberta's mining, quarrying, and oil and gas extraction sector would be the second lowest after 2009, when investment in the sector was $21.9 billion. The actual results for 2019 are expected to be released in 2021.

Although the investment in the mining, quarrying, and oil and gas extraction industry in Alberta was down substantially from the 2014 level, which at $61 billion was the record high annual investment in the sector, Alberta still attracted more investment in this industry than all of the rest of Canada combined. In 2019, investment in Alberta's upstream energy industry was estimated to account for 54 per cent of the total Canadian investment in this industry.

[i] Further information on sources and methodoloy for this performance indicator can be found in the Performance Measure and Indicator Methodology section on page 82.



Source: Statistics Canada [i]

It is significantly more difficult to examine the downstream energy industry than the upstream, as the downstream impacts are diffused throughout different industries, and, therefore, cannot be easily captured. Due to these limitations, downstream investment is focused on petroleum and coal product manufacturing, and chemical manufacturing. This allows for the coverage of petroleum refining and petrochemical manufacturing activity, among other downstream activities.

Overall, the trends that were observed, in Alberta, for the upstream energy industry investment over the 2015-2019 period did not consistently translate into similar trends for the downstream investment. The smaller downstream capital investment is much more susceptible to significant year-over-year swings due to major one-time investment decisions that may not actually reflect industry trends. In fact, the preliminary actual results indicate that while Alberta's upstream energy sector investment declined from 2018 to 2019, investment in the downstream actually went up, from about $1.9 billion to an estimated $2.3 billion. Preliminary overall Alberta downstream investment in 2019 was estimated to be about $409 million, or almost 22 per cent higher compared to 2018. It is difficult to determine the trend for Alberta downstream investment, which consists of a range of industries with varying manufacturing end products.

[i] For more information, see the Performance Measure and Indicator Methodology section on page 81.

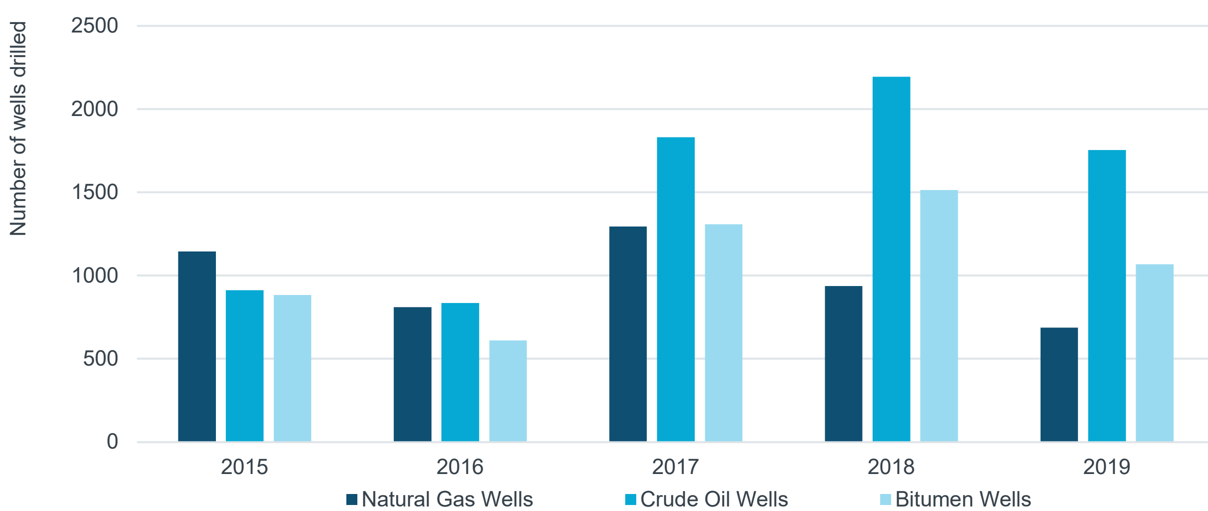
Upstream versus Downstream – What is the difference?

The terms upstream and downstream refer to activities at different points of the energy sector supply chain. Upstream operations include exploration and extraction of naturally occurring minerals such as crude petroleum, natural gas and coal. The production of conventional oil and gas, and the mining and extraction of oil from oil sands are included in the upstream sector. Alberta plays a major role in Canada's upstream energy industry.

Downstream activity includes the transformation of crude petroleum, natural gas and coal into intermediate and end products, through processes such as petroleum refining. Downstream activity also includes petrochemical manufacturing. Downstream activity creates additional economic impacts for Alberta; however, it is significantly more difficult to demonstrate these impacts compared to the upstream energy industry, as downstream impacts are dispersed throughout different industries. Due to these limitations, downstream activity in the Annual Report is focused on petroleum and coal product, and chemical manufacturing.

Drilling

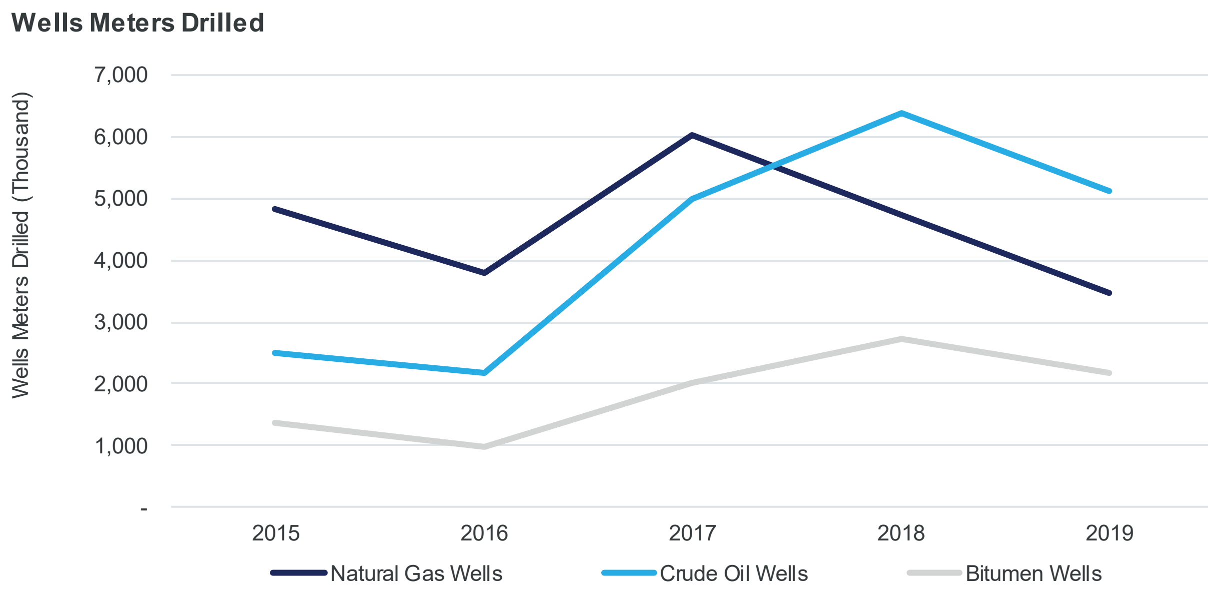
Drilling Activity in Alberta



Source: Alberta Energy Regulator

The above chart presents drilling activity in Alberta over the 2015-2019 period. Wells drilled include both development and exploratory wells. After the significant decline in the total number of wells drilled in Alberta in 2015 and 2016, drilling activity increased in 2017. In 2018, the number of crude oil and bitumen wells continued to increase relative to the 2017 level, while the number of natural gas wells declined. In 2019, drilling activity declined for all three types of wells – crude oil, bitumen and natural gas wells.

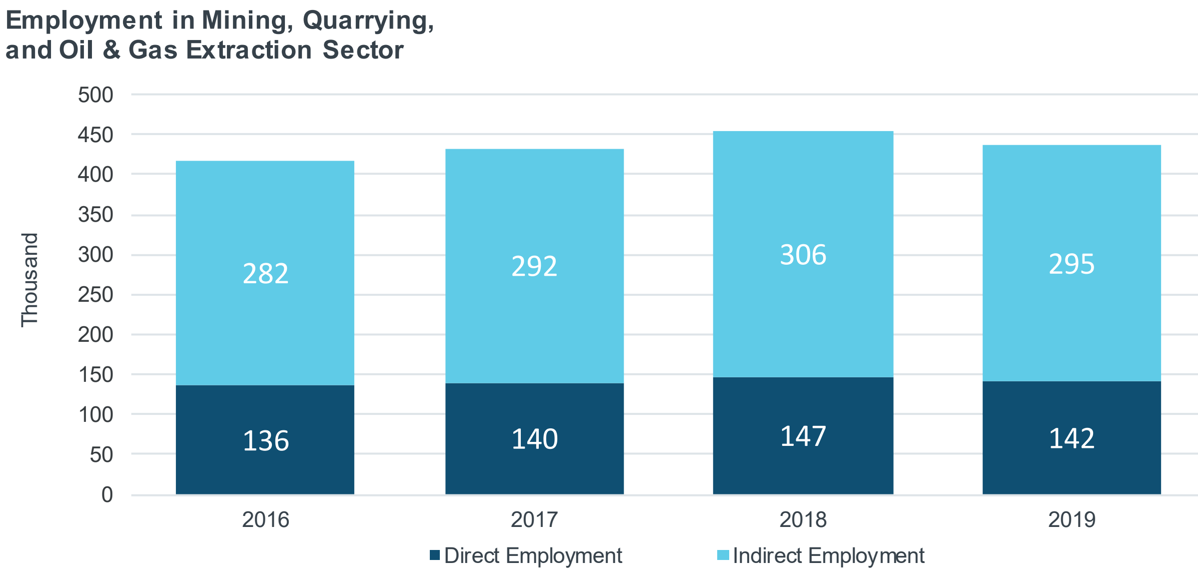
The total successful natural gas wells drilled decreased by 27 per cent, from 937 in 2018 to 687 in 2019, as low prices, capital restraint by producers and pipeline capacity constraints contributed to decreased activity across the province. Similarly, the total successful crude oil wells drilled decreased by 20 per cent, from 2,194 in 2018 to 1,755 in 2019 due to market access and policy uncertainty, along with conservative capital programs. Bitumen wells drilled also followed the downward trend, decreasing by 29 per cent from 1,515 in 2018 to 1,069 in 2019.



Source: Alberta Energy Regulator

Between 2015 and 2019, the lowest total number of meters drilled in crude oil and bitumen wells occurred in 2016, while for natural gas it was in 2019. This was primarily due to fewer wells being drilled for crude oil, bitumen and natural gas, respectively, in those years.

Employment



Source: Statistics Canada[i]

Upstream energy sector employment has been important to Alberta's economic performance. The 2014 decline in oil prices had a major impact on employment in Alberta's mining, quarrying, and oil and gas extraction sector. From 2015 to 2016, direct employment in this sector in Alberta declined by about 13 per cent, from 155,000 to 136,000 people. In 2017, employment in the upstream energy sector increased by three per cent from the 2016 level to 140,000 people. From 2017 to 2018, employment in this sector went up by a further five per cent to 147,000 people. However, in 2019, about 142,000 people were employed in the mining, quarrying, and oil and gas extraction sector in the province, so employment in the sector declined by about four per cent relative to its 2018 level.

When indirect employment in mining, quarrying, and oil and gas extraction is taken into account, Alberta's total employment in the sector declined from about 454,000 people in 2018 to approximately 436,000 people in 2019. Total direct and indirect employment in the sector in 2019 corresponded to about 19 per cent of total employment in Alberta in 2019. In the case of employment in mining, quarrying, oil and gas extraction, an example of the direct employment impact is an oil rig worker; indirect impact would include an employee who works at the power station which supplies the oil rig with electricity.

The indirect employment results reported for the 2016 to 2018 period have been retroactively revised in this annual report from what was reported in the 2018-19 Annual Report to reflect a more current multiplier from Statistics Canada, which has resulted in an upward revision of indirect employment results for this period.

[i] Note: Totals may not add up precisely due to rounding.

Royalty Programs

The Government of Alberta owns 81 per cent of oil and gas resources in Alberta and collects royalties from companies when an oil or gas well, oil sands project, or mineral project is in production. On behalf of Albertans, the ministry reviews and maintains a competitive and effective royalty regime that attracts industry investment, which provides jobs, business opportunities, tax and royalty revenue and numerous other benefits to the provincial economy. This work supports outcome one from Energy's 2019-23 Business Plan: Albertans benefit economically from investment in responsible energy and mineral development and access to global markets.

Royalty programs exist for a number of reasons, such as:

- to provide appropriate royalty structure to attract investment in Alberta's energy sector in specific situations where the overall regime needs adjustment to achieve strategic investments;
- to encourage the development, use and commercialization of innovative technologies to produce resources; and
- to achieve certain strategic policy objectives such as increased value-added upgrading.

Two royalty frameworks currently run programs in Alberta, the Modernized Royalty Framework and the Alberta Royalty Framework.

As the Modernized Royalty Framework took effect on January 1, 2017 and includes two new strategic programs, wells that were previously operating under the Alberta Royalty Framework and its programs are being grandfathered, either for a period of 10 years or until they reach certain expiring milestones already built into the programs.

To understand reporting for the royalty programs under the two frameworks, it is important to consider the following points:

- The total royalty revenue of each royalty program is sourced from various royalty reporting systems for crude oil, natural gas and oil sands. Amendments by industry can be filed for up to three years from the production month. In addition, the total royalty revenue of each royalty program reflects the revenue from wells that are qualified for the respective royalty programs in a given year. It does not represent the net revenue from those wells as the royalty revenue on natural gas and gas products can be further reduced by eligible deductions, such as the Gas Cost Allowance.
- The royalty programs under the Alberta Royalty Framework are reported on a calendar year basis and reflect the amendments filed by industry each year.
- The royalty programs under the Modernized Royalty Framework are reported on a fiscal year basis to align with government reporting as a whole and reflect amendments filed by industry each year.

In June 2019, the Government of Alberta introduced the *Royalty Guarantee Act* to increase investor certainty that the royalty structure in place when a well is drilled will remain in place for at least 10 years. More discussion on this can be found on page 46 of this report.

Modernized Royalty Framework Royalty Programs

The Modernized Royalty Framework creates harmonized royalty formulas for crude oil, liquids and natural gas-based investment and encourages industry to reduce costs. In 2017, the department established two programs under the Modernized Royalty Framework: the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program.

Enhanced Hydrocarbon Recovery Program

This program came into effect on January 1, 2017 to promote incremental production through enhanced recovery methods intended for legacy fields, and replaces the Enhanced Oil Recovery Program that is being phased out. Enhanced recovery methods use the injection of fluids such as water, hydrocarbons, carbon dioxide, nitrogen, polymers or chemicals to recover additional hydrocarbon reserves.

The objectives of the Enhanced Hydrocarbon Recovery Program are to:

- provide appropriate royalty treatment for incremental hydrocarbon production to account for the higher costs associated with enhanced recovery methods;
- generate incremental hydrocarbon production through enhanced hydrocarbon development; and
- collect incremental royalty revenue for Alberta over the long-term.

During the 2018-19 fiscal year, the Enhanced Hydrocarbon Recovery Program received 12 applications. In total, 23 applications from 16 companies have been received, and seven applications have been approved since the program's inception in 2017. Enhanced recovery techniques are typically used in a phased approach in legacy fields where primary production has already occurred. Three applications for the secondary recovery phase of oil, which includes enhancing the recovery of oil from an oil pool by water flooding, gas cycling, gas flooding, polymer flooding or similar techniques, were approved during 2018-19. One application for the tertiary recovery phase of oil, which includes enhancing the recovery of oil from an oil pool by miscible flooding, immiscible flooding, solvent flooding, chemical flooding or similar techniques, was approved during 2018-19.

	2017-18	2018-19
Total Crown Royalty Volumes – Oil (m^3)	1,071	2,698
Total Crown Royalty Volumes – NGL (m^3)	377	6,951
Total Crown Royalty Volumes – Gas (10^3m^3)	14,815	66,275
Total Royalty Revenue ($)	441,104	1,300,308
Incremental Crown Royalty Revenue ($)	233,380	575,173

The active enhanced recovery schemes in the program generated a total Crown production of 53,936 cubic metres of oil, and 69,506,900 cubic metres of gas in 2018-19. In comparison, active enhanced recovery schemes generated a total Crown production of 21,426 cubic meters of oil, and 11,183,200 cubic meters of gas in 2017-18.

Total Crown royalty volumes from the approved enhanced recovery schemes totaled 2,698 cubic metres of oil, 6,951 cubic metres of natural gas liquids and 66,275,100 cubic metres of gas, which translates to about $1.3

million in total royalty revenue in 2018-19. Of this total royalty revenue, about $0.6 million was considered incremental royalty to the Crown that otherwise would not have been generated without the program.

It is important to note that, without the program support, enhanced recovery schemes are generally not economic and unattractive to investors due to higher production costs and lower rates of return on investments. Without the program, the enhanced recovery schemes may not proceed to even produce the base production. In that regard, any royalty generated from those enhanced recovery schemes could be considered "incremental" to the Crown.

Emerging Resources Program

The Emerging Resources Program came into effect on January 1, 2017. This program encourages industry to develop new oil and gas resources in higher-risk and higher-cost areas that have large resource potential. The objectives of the Emerging Resources Program are to:

- provide appropriate royalty treatment for strategic emerging oil and gas resources that are high cost and high risk;
- promote innovation and industry experience to accelerate the development of these resources; and
- generate incremental royalty revenue for Albertans over the long-term.

During the 2018-19 fiscal year, the Emerging Resources Program received six applications. Since the program was launched, 17 applications from 12 companies have been received, including seven applications that were approved, eight applications that were denied, one that was withdrawn, and one that is currently under review.

The cumulative number of new project wells participating in the program in 2018-19 was 3,291. The number of new project wells increased by 282 in 2018-19.

	2017-18	2018-19
Number of New Project Wells	3,009	282
Cumulative Number of Project Wells	3,009	3,291

Approved projects in the program generated a total Crown production of 147,730 cubic metres of oil, 32,507 cubic metres of condensate, and 221,923,700 cubic metres of gas in 2018-19.

Total Crown royalty volumes from Emerging Resource Program projects totaled 7,387 cubic metres of oil, 147,147 cubic metres of natural gas liquids, 32,507 of condensate, and 180,892,600 cubic metres of gas. This translates to about $6.5 million in total royalty revenue in 2018-19 from approved Emerging Resource Program projects. This royalty revenue to the Crown may not have been generated without the program incentives.

Alberta Royalty Framework Royalty Programs

The department has a number of royalty programs under the Alberta Royalty Framework that, as of 2017, are no longer accepting new entrants and will be phased out once their regulation expires. The programs to be phased out include the Natural Gas Deep Drilling Program, Emerging Resources and Technologies Initiative, Incremental Ethane Extraction Program and the Enhanced Oil Recovery Program. The ministry will continue to monitor and report on the progress of these programs until they officially expire.

Natural Gas Deep Drilling Program

The Natural Gas Deep Drilling Program (NGDDP) has been making progress towards achieving its intended outcomes of encouraging new exploration and developing production by providing a royalty adjustment to wells with a vertical depth greater than 2,000 metres.

The royalty adjustment is based on the well's measured depth and is provided for a period of up to five years following the wells finished drilling date. The minimum royalty rate applied to natural gas and natural gas products is five per cent. For condensate, the minimum adjustment rate is zero.

The total residue gas production from eligible wells has decreased by 32.3 per cent and liquids production has decreased by 39.1 per cent. Residue gas is the gas mixture left after separation and processing of natural gas liquids that are ready for delivery to the pipeline. The decrease in residue gas and liquids production is due to the termination of the program enrollment.

	Prior Year's Results				Current 2018
	2014	2015	2016	2017	
Total gas production from eligible wells	Residue Gas: 28,557,344 Liquids: 6,503,491	Residue Gas: 35,335,955 Liquids: 9,182,083	Residue Gas: 38,752,706 Liquids: 12,138,887	Residue Gas: 33,746,930 Liquids: 13,274,152	Residue Gas: 22,850,190 Liquids: 8,084,252
Total Royalty from NGDDP gas wells	$378 million	$280 million	$261 million	$307 million	$176 million

Note: Units of measurement for gas is 10^3m^3 and liquids is m^3

The total royalty revenue for NGDDP has decreased by 42.6 per cent from the 2017 result. In the 2018 calendar year, gas wells in the program contributed about $176 million in total royalty revenues. Total royalty revenue has decreased by $131 million from 2017. The decline in royalty revenue is consistent with the decline in production under the program. This is likely due to well production decline, or wells reaching the NGDDP net cap or 60 calendar months cap.

NGDDP no longer accepts new wells into the program as of December 31, 2016, as the program is phasing out.

The Emerging Resources and Technologies Initiative

Introduced in 2010, the purpose of the Emerging Resources and Technologies Initiative (ER&T) is to stimulate investment and encourage development of Alberta's unconventional resources through the deployment of new technologies. The initiative supports new exploration, development and production from Alberta's emerging resources in horizontal oil, shale gas, horizontal gas and coalbed methane. The ER&T was implemented to increase investors' ability to recover upfront investments by extending the maximum five per cent New Well Royalty Rate to acknowledge the higher costs and risks associated in the following four situations: horizontal oil, horizontal gas, shale gas and coalbed methane. No new wells have been accepted into the program since December 31, 2016.

Production under the program is measured for wells in each of the four situations. In shale gas wells, horizontal gas wells and horizontal oil wells, the production has decreased significantly. This is the result of expected production declines in existing wells. In 2018, no new wells qualified for the program and production began to decline in existing wells.

Overall gas production in coalbed methane wells continues on a year-over-year downward trend until 2018 when the production increased. The increase in Coalbed Methane New Well Royalty Rate production in 2018 is because the majority of the coalbed methane wells were qualified in the last quarter of 2017; as a result, the production volumes were higher in 2018. In addition to other factors (such as coalbed methane being less economical than other available alternatives), the timing of when coalbed methane wells enter or exit the program affects the production volume, which is evident from the increase in production in 2018. The economics of **coalbed methane** wells continue to be challenging compared to other gas wells. Despite relatively low drilling costs, the supply cost for coalbed methane wells are among the highest. Coalbed methane wells produce mainly dry gas and have very low initial production rates. In addition, coalbed methane wells are typically drilled on a single-well basis and do not benefit from economies of scale associated with drilling multiple wells at one location. This is commonly used in tight and shale formations.

Overall production from **horizontal oil and gas** wells decreased in 2018 compared to 2017. Gas production under the horizontal gas new wells decreased to 0.6 billion cubic metres in 2018 from 4.3 billion cubic metres in 2017. Liquids production also saw a decrease to 0.3 million cubic metres in 2018 from 2.9 million cubic metres in 2017. This is due to termination of the program and high decline rate of the existing well productions. As wells reach their caps, the number of qualified wells decreases; therefore, production decreases.

Horizontal oil wells showed decreases of 66.7 per cent and 92.3 per cent in 2018 oil production and solution gas production, respectively, from 2017 to 2018. Oil production decreased to 0.8 million cubic metres in 2018 from 2.4 million cubic metres in 2017. Solution gas production decreased to 0.03 billion cubic metres in 2018 from 0.4 billion cubic metres in 2018. These decreases are due to termination of the program and high decline rate of the existing well production. Solution gas is the gas that is separated from crude oil or crude bitumen after recovery from a well event.

Production from **shale gas** wells include shale gas, liquids, oil and solution gas. Production from shale gas wells has decreased since no new wells qualified for the program in 2017. In the 2018 calendar year, gas production from shale wells decreased to 0.1 billion cubic metres from 0.6 billion cubic metres from 2017 level.

The total royalty revenue for ER&T in 2018 was approximately $62 million compared to the 2017 total royalty revenue of $238.9 million. Total revenue generated by wells in the program has decreased by 74.1 per cent compared to 2017. This accounts for 4.0 per cent of Alberta's total conventional Crown oil and gas revenues. Due to the fact that no new wells were accepted into the program, the 2018 newly added wells were previously drilled wells with no previous production. This means that their production volumes will likely be low for 2018, and even more so for 2019 and beyond. With prolonged low commodity prices, the total contribution of these wells to royalty revenue will likely be limited too.

The results for the ER&T only reflect the wells that are qualified and receiving program benefits for a given year. As discussed previously, the ER&T lowers the royalty rate for qualified wells at the beginning of a well's production life for a limited time period (up to four years) or a maximum production amount. This is intended to reduce the return-on-investment time period for owners and to maintain Alberta's competitiveness. Most of these wells continue to produce and generate additional royalty revenue and other economic benefits for the Crown after they exit the program.

Incremental Ethane Extraction Program

Implemented in 2007, the Incremental Ethane Extraction Program (IEEP) provides $350 million in royalty credits to petrochemical companies that consume incremental ethane for the production of higher-value products, such as ethylene and its derivatives. The objective of the IEEP is to supply an additional 60,000 to 85,000 barrels per day of ethane for petrochemical companies to use as feedstock.

The program allows for a 60-month royalty credit eligibility period. In the 2018 calendar year, 13 of the 16 approved projects were in-service for the program. These 13 in-service projects are capable of providing up to 85,073 barrels per day of additional ethane or about 93 per cent of the total approved incremental ethane capacity approved by the minister for the IEEP. In the 2019-20 fiscal year, the department issued approximately $71 million in royalty credits to these projects for 2018 production.

Approximately 80 per cent of the incremental ethane capacity was from natural gas sources with the remaining 20 per cent obtained from off-gas sources.

The supply and demand for ethane has continued to strengthen over the past few years and Alberta's petrochemical supply and demand balance is considered stable. The department will continue to process royalty credits associated with in-service ethane extraction projects that are within their 60-month credit eligibility period. The IEEP is being phased out and is scheduled to end on December 31, 2021.

Enhanced Oil Recovery Program

The Enhanced Oil Recovery Program was implemented in 2014 and has been making progress towards achieving its intended outcomes. This includes encouraging incremental crude oil production through enhanced oil recovery methods. This involves injecting approved materials other than water to increase oil recovery from a pool at existing developments. The program provides a maximum five per cent royalty rate for all oil produced from program-approved schemes for a defined period of up to 120 months. The program is intended to encourage increased investment in incremental oil production, realize incremental royalty volumes and ultimately increased royalty revenue.

No new applications were received in 2018 under this program, and no new schemes were approved into the program since the program is being phased out.

Total Crown production from enhanced oil recovery in 2018 was 0.6 million cubic metres, which is a decrease of 74,994 cubic metres from the previous year. The Crown royalty volumes from active enhanced oil recovery schemes totaled to 103,891 cubic metres, which translates to approximately $45 million in total royalty revenue in 2018. The total royalty revenue increased by over $7 million in 2018 from approximately $37 million reported in 2017. This is due to much higher WTI price in 2018 of about US$65/bbl compared with US$51/bbl in 2017. Higher WTI price leads to higher royalty rates. Of this total royalty revenue, approximately $42 million was considered incremental royalty to the Crown that otherwise would not have been generated without the program. This is a $7 million increase from approximately $35 million in incremental royalty revenue reported in 2017.

It is important to note that, without the program support, enhanced oil recovery schemes are generally uneconomic and unattractive to investors due to higher production costs and lower rates of return on investments. Without the program, the enhanced oil recovery schemes may not proceed to even produce the base oil production. In that regard, any royalty generated from those enhanced oil recovery schemes could be considered “incremental” to the Crown.

Red Tape Reduction

The Ministry of Energy is committed to the ongoing review of programs and services to ensure that the best possible outcomes are being achieved for Albertans. As part of this ongoing review, the ministry is committed to reducing red tape to make life easier for hard-working Albertans and businesses. This includes reducing regulatory burden and unnecessary processes to encourage economic growth and job creation; and to make Alberta one of the freest and fastest-moving economies in the world.

Energy has taken significant steps to simplify and reduce the regulatory burden on our energy sector and completed a number of red tape reduction initiatives in 2019-20, including:

- repealing unnecessary and outdated regulations and legislation, such as the *Small Power Research and Development Act* and its regulation;
- enabling the Orphan Well Association to better manage and accelerate the clean-up of wells or sites which do not have a responsible owner;
- eliminating departmental reviews of oil sands scheme approvals following Alberta Energy Regulator approval;
- enhancing curtailment rules, reducing the regulatory and administrative burden on oil producers;
- clarifying rules around Crown mineral activity authorization and tenure disposition;
- reversing the capacity market;
- simplifying processes for electricity and natural gas utility advertising;
- eliminating the Transmission Facilities Cost Monitoring Committee to avoid duplication with the Alberta Utilities Commission; and
- removing the requirement for new legislation for small-scale and low-impact hydroelectric developments.

In support of this work, the ministry engaged industry to help identify reductions and participated in an oil and gas industry panel to solicit direct input into red tape reduction initiatives. Increasing process efficiency, enhancing the use of data, and harmonizing interprovincial trade have been identified as important improvements. Industry and public submissions continue to be reviewed and assessed within Energy's multi-year red tape reduction plan.

More information on the red tape reduction initiatives mentioned above can be found through out the results analysis for Outcome 1 and 2.

Discussion and Analysis of Results

Outcome One

Albertans benefit economically from investment in responsible energy and mineral development and access to global markets.

What it means:

The ministry develops and manages policies and programs related to the province's royalty system to attract industry investment, provide jobs, business opportunities, tax revenue, and numerous other benefits to the provincial economy. It advocates for increased pipeline access to global markets to strengthen both provincial and national economies, while proactively communicating how we produce energy with the highest environmental, labour, and human rights standards in the world. It seeks to influence challenges facing the natural gas sector, including those related to market access, price volatility, and intra- and interprovincial natural gas transportation and storage. The ministry advances a modern, market-based electricity system in Alberta that attracts investment and provides affordable electricity for consumers and job creators. Ministry activities to reduce burdensome red tape and improve investor certainty in the energy sector will further these outcomes and help get Albertans back to work.

Key objectives to support the achievement of this outcome include:

- 1.1 Improve market access for Alberta's energy resources and products through advocacy and other support for new and expanded pipelines, while seeking to create alignment on resource corridors to expedite future major pipeline approvals.
- 1.2 Establish the Canadian Energy Centre to respond in real time to misinformation about Alberta's energy industry.
- 1.3 Launch a public inquiry into foreign sources of funds behind the anti-Alberta energy campaigns.
- 1.4 Create an investment climate that supports the development of energy resources in the province.
- 1.5 Implement a robust natural gas strategy, including the optimization of the Western Canadian pipeline network and pursuit of opportunities for increased pipeline capacity and markets within Alberta.
- 1.6 Implement initiatives that support natural gas value chains and value-added processing in the province.
- 1.7 Ensure Alberta participates in global liquefied natural gas opportunities.
- 1.8 Increase certainty in the wholesale electricity market, creating the conditions for future investment in generation and the welcoming of market driven investment in renewable energy generation.

Key Objective 1.1

Improve market access for Alberta's energy resources and products through advocacy and other support for new and expanded pipelines, while seeking to create alignment on resource corridors to expedite future major pipeline approvals.

Increasing market access and protecting the value of Alberta's energy exports is a top priority for government. Without proper access to world markets, Canada – and Alberta – continues to lose billions of dollars.

Alberta is advocating for all projects that secure additional market access for provincial oil producers, through activities such as:

- tracking key developments for projects that will increase market access for Alberta oil and gas producers;
- intervening at Canada Energy Regulator hearings that affect Alberta oil and gas interests;
- addressing federal legislation that impacts major infrastructure development and market access for Alberta crude, including the *Impact Assessment Act* and the *Oil Tanker Moratorium Act*;
- asking Alberta's energy industry to increase advocacy efforts; and
- building an interprovincial coalition of provinces which support jobs, pipelines, and our energy industry.

All major pipeline projects have experienced, or are experiencing, delays due to regulatory and legal challenges at the state or federal levels. In response to this, Energy works closely with the Alberta Washington Office and pipeline proponents to ensure the province takes advantage of all opportunities to advocate or intervene on pipeline-related matters throughout North America. Government of Alberta officials have travelled throughout Canada and the United States to advocate for market access projects. Expenses related to this travel are posted online at www.alberta.ca.

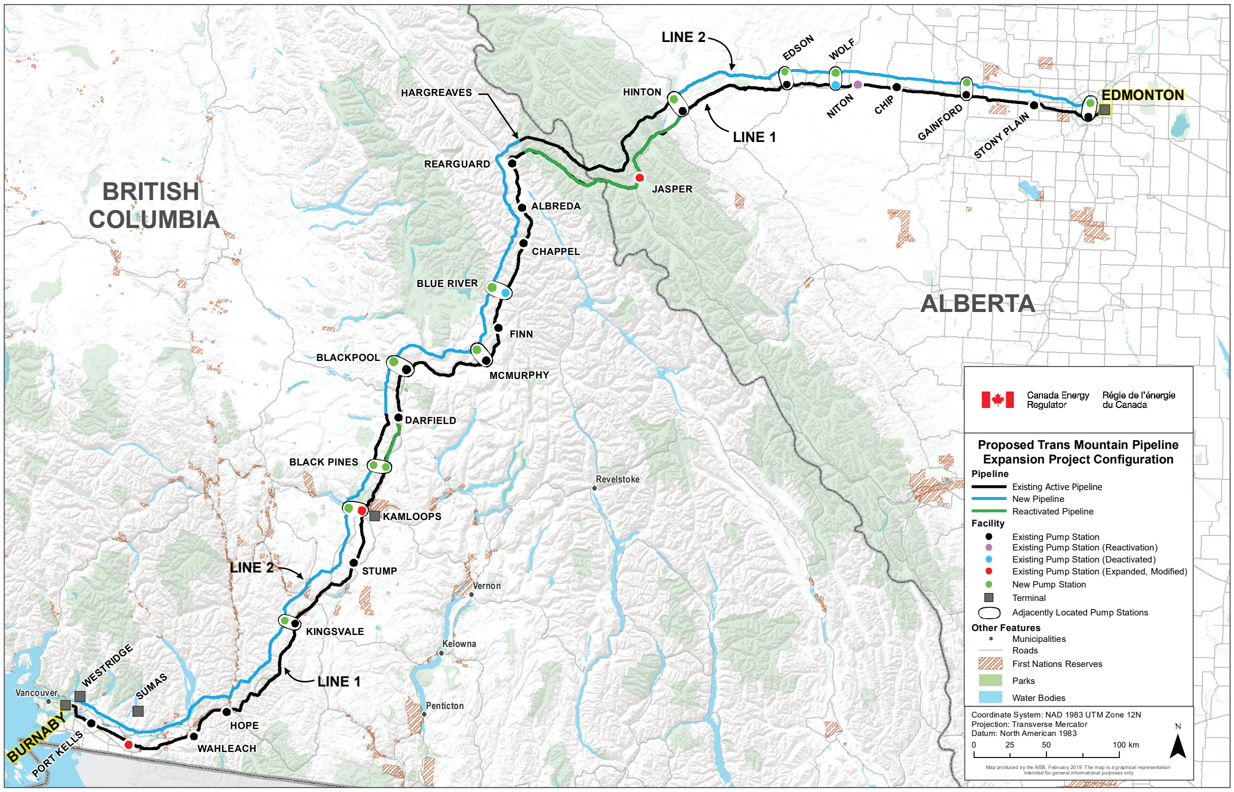
Market access activities for the department cost $866 million in 2019-20, predominately for the divestment of Crude by Rail program to industry. The department incurred $3.0 million for all other activities associated with the market access items identified in the following sections.

Trans Mountain Expansion Project

The Trans Mountain Pipeline Expansion Project is a twinning of an existing 1,150-kilometre pipeline between Strathcona County, Alberta and Burnaby, British Columbia, originally built in 1953. Nominal system capacity will increase from approximately 300,000 barrels per day to 890,000 barrels per day. This pipeline expansion project is critical to increasing market access.

While the project was originally approved by the federal government in November 2016, there have since been several major developments. The federal government purchased the pipeline from Kinder Morgan for $4.5 billion in May 2018, and in August 2018, a Federal Court of Appeal decision rescinded the project's approval. In response to the decision, the federal government directed the National Energy Board to reconsider marine tanker traffic impacts as a result of the project. The federal government also undertook additional consultation with Indigenous groups.

In 2019, the project was re-approved by the federal government and construction resumed on the British Columbia portion of the Trans Mountain Expansion Project, at the Westridge Marine Terminal and Burnaby Terminal, in the summer of 2019 and in Alberta in December 2019. In February 2020, the Federal Court of Appeal dismissed all judicial review applications seeking to challenge the approval of the Trans Mountain Expansion Project. In March, the Supreme Court of Canada also denied appeals of the ruling.



Source: Canadian Energy Regulator

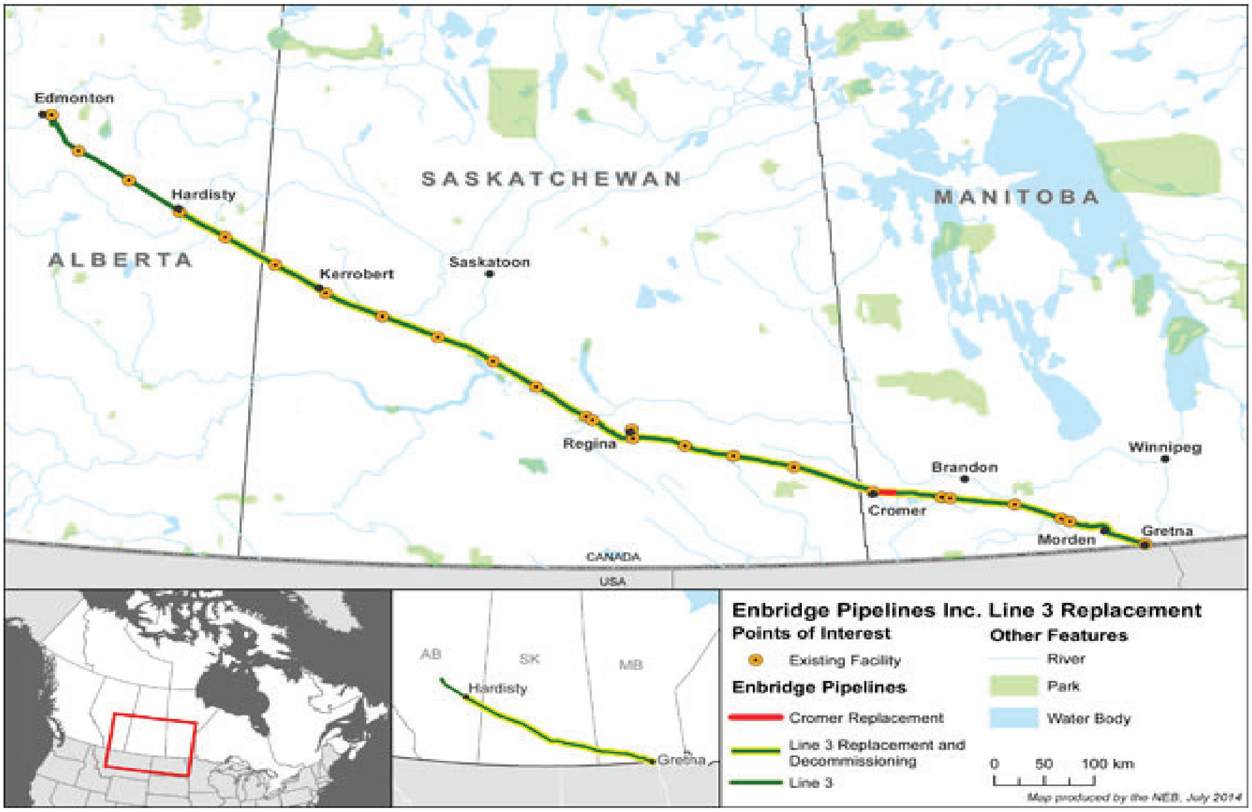
The projected cost to complete the Trans Mountain Expansion Project increased from $7.4 billion to $12.6 billion due to legal challenges which led to approximately one year of construction delays, as well as costs related to additional safety and environment standards, improvements, risk management and other contingencies by Trans Mountain.

In early 2019, the Government of Alberta struck a cross-ministry working group composed of permit-issuing departments as well as departments with other responsibilities related to the Trans Mountain Expansion Project. The group works closely with the project proponent to coordinate and process permits in a timely manner to mitigate delays and advance construction within Alberta. Members of the working group are the Ministries of Environment and Parks, Transportation, Infrastructure, Municipal Affairs, Energy, Justice and Solicitor General and Indigenous Relations. The Government of Alberta also began working with counterparts at Natural Resources Canada in early 2020 to share information related to federal, British Columbia and Alberta permitting as construction progresses. As of May 2020, approximately 60 per cent of pipe installation in the Greater Edmonton area was complete. It is expected that construction along the entire pipeline route will be underway by the end of 2020.

Enbridge Line 3

The Enbridge Line 3 Replacement is the largest project in the company's history. It will upgrade 1,660 kilometres of a 60-year old pipeline between Hardisty, Alberta and Superior, Wisconsin and increase capacity from the current 390,000 barrels per day to 760,000 barrels per day. In December 2019, the Canadian segment of Line 3 came into service. The Canadian segment, plus other optimizations on the Enbridge Mainline system, added approximately 100,000 barrels per day of additional pipeline capacity for western Canadian oil producers.

The Line 3 Replacement Project in the United States has experienced delays due to a state-level court ruling in Minnesota. In February 2020, the Minnesota Public Utilities Commission (PUC) re-approved three major permits (environmental, routing and need) that were found inadequate by a state-level court in 2019. Enbridge still requires an unknown number of remaining state permits before the PUC issues an "Authorization to Construct" order. Once fully permitted, construction will take approximately six-to-nine months to complete and could be in service by late 2020.



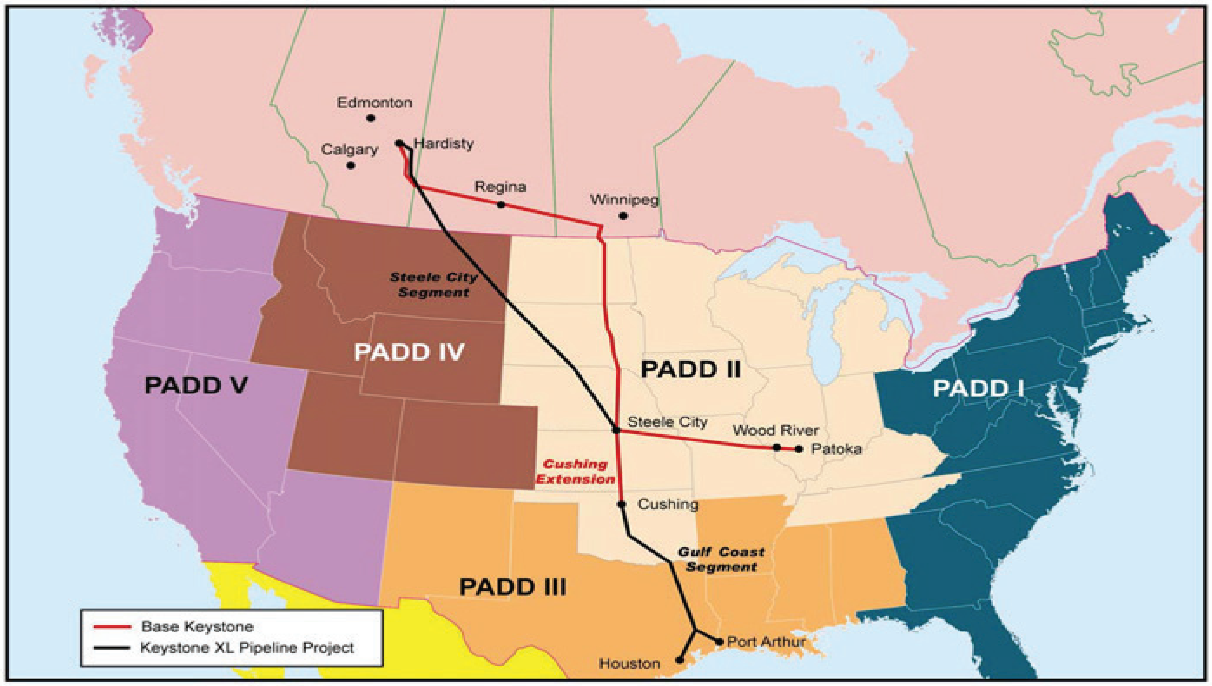
Source: Canadian Energy Regulator

Keystone XL

The Government of Alberta continues to advocate for the completion of Keystone XL. Keystone XL will span 1,947 km between Hardisty, Alberta, to Steele City, Nebraska. It will add to the capacity of the existing Keystone Pipeline System to deliver up to 830,000 barrels of Canadian crude oil each day, meeting demand for heavy crude at U.S. Gulf Coast refineries.

On March 31, 2020, the government finalized an agreement with TC Energy Corporation providing financial support to accelerate construction of the KXL pipeline that began April 1, 2020. This investment provided $1.5 billion in equity investment in 2020 followed by a $6 billion loan guarantee in 2021. TC Energy will reimburse the Government of Alberta 12 months after oil is flowing through the pipeline.

In March 2019, President Donald Trump issued a new Presidential Permit, and, in December 2019, the U.S. State Department issued the Final Supplemental Environmental Impact Statement (FSEIS), a significant approval that affirmed the project can be built safely and responsibly. Alberta submitted a letter of support for the project during the public comment FSEIS process.



Source: Canadian Energy Regulator

Following the issuance of the FSEIS, the company secured permits required for construction and completed work at the Canada-Montana border in April 2020. While a Montana District court decision suspending a key water permit for the project is navigating the appeals process, the company is still working to secure remaining U.S. federal permits and continuing to complete work not impacted by the court decision. There are also currently three legal challenges filed against the Keystone XL Project brought forward by a number of Indigenous and environmental groups.

The project is expected to be completed and in service in 2023. It is estimated that the project will create more than 1,400 direct and 5,400 indirect jobs in Alberta during construction and will generate an estimated $30 billion in tax and royalty revenue for future generations of Albertans and Canadians.

Federal Advocacy

The Government of Alberta has been working for several years advocating for Alberta's resource sector, and against the *Impact Assessment Act* and the *Oil Tanker Moratorium Act*. These *Acts* have had a significant impact on Alberta's energy resource sector. In 2019-20, the Ministry of Energy continued to advocate for Alberta's interests and request clarity and amendments on many issues that exist with this legislation.

The *Impact Assessment Act,* formerly Bill C-69, was proclaimed by the federal government in August 2019. The Government of Alberta sent letters and technical input to the federal government and the Senate expressing concerns over the course of several years, and Premier Kenney and Minister Savage presented Alberta's position to the Senate committee studying the bill in May 2019, urging the committee to accept the amendments.

The *Impact Assessment Act* will:

- Further erode confidence in Canada's regulatory framework and deter investment in a country already seen as too risky a place to invest.
- Exceed federal jurisdiction by granting federal powers to regulate provincial projects — including in situ oil sands developments — that are entirely within provincial borders and already subject to provincial regulation. This overreach is also contrary to the *Constitution Act* and a 1992 Supreme Court ruling.
- Ignore exclusive provincial authority as per Section 92A of the Constitution, which was agreed to by Premier Lougheed and the federal government in 1982.

In September 2019, the Government of Alberta launched a constitutional challenge against this piece of legislation, which will have devastating impacts on Albertans and Canadians.

The federal government proclaimed the *Oil Tanker Moratorium Act*, formerly Bill C-48, in June 2019. The *Act* imposes an indefinite ban on tankers carrying more than 12,500 tonnes of crude oil or persistent oils – approximately 85,000 barrels – from stopping, loading and unloading along B.C.'s north coast. Banned products include crude oil, partially upgraded bitumen, diluted bitumen, marine diesel and bunker fuel, and synthetic crude, among others.

Other organizations opposed to the act that testified in front of the Senate committee include: the Canadian Association of Petroleum Producers; Suncor; Cenovus; B.C. Chamber of Shipping; port authorities; business associations; Western Canada Marine Response Corporation; Canada West Foundation; Aboriginal Equity Partners; and the Indian Resource Council.

Preserving Canada's Economic Prosperity Act

The Government of Alberta proclaimed the *Preserving Canada's Economic Prosperity Act* on April 30, 2019. The Act gives Alberta the ability to halt or restrict the export of crude oil, natural gas and refined fuels to other jurisdictions, including provinces, if necessary.

Building Interprovincial Coalition of Provinces

The Ministry of Energy hosted and participated in several national meetings to bring issues that matter most to Albertans to the forefront of the national agenda.

In June 2019, premiers met at the Western Premiers' Conference, chaired by Premier Kenney, in Edmonton. The discussions at the Conference led to shared support for economic corridors to facilitate oil and gas pipelines and to improve interprovincial trade. Premiers agreed that each jurisdiction would benefit from improved access to new markets and committed to bringing this topic up at the upcoming Council of Federation meeting in July 2019.

During the annual Stampede premiers' meeting in Calgary in July 2019, which included premiers from New Brunswick, Ontario, Saskatchewan, and the Northwest Territories, the premiers built on the conversations from the Western Premier's Conference, by discussing actions that can be taken individually and collectively to create good jobs, support responsible resource development, get Canadian energy to global markets, create economic corridors, reduce barriers to interprovincial trade and labour mobility, and other important economic issues.

In July 2019, premiers met again at the Council of the Federation meeting in Saskatoon. During this meeting, Premier Kenney took the bold step of unilaterally dropping all of Alberta's procurement exceptions to the 2017 Canadian Free Trade Agreement, and secured support from 12 of 13 provinces and territories for economic corridors. Alberta is leading an interprovincial working group that is exploring the concept of economic corridors.

Alberta initiated interprovincial agreements to address mutual priorities, including a joint premiers' letter between Alberta, Saskatchewan, Manitoba, Ontario and New Brunswick expressing disappointment with federal legislation (the *Impact Assessment Act* and the *Oil Tanker Moratorium Act*), and a joint ministerial statement and press conference by Alberta, Ontario and Saskatchewan on the *Impact Assessment Act* amendments.

In December 2019, Premier Kenney led a delegation of ministers, including the Minister of Energy, on a mission to Ottawa to press for a fair deal for Alberta. The missions focused on a wide range of issues, including methane equivalency, pipelines, oil and gas well reclamation, and the *Oil Tanker Moratorium Act.*

In February 2020, Premier Kenney promoted investment and pipelines through meetings held in Montreal and Washington. In Montreal, Premier Kenney spoke with a roundtable of top business leaders, and met with CEO's of Canada's largest corporations to discuss the benefit to all Canadians from a thriving energy sector. While in Washington, Premier Kenney met with senior cabinet members to discuss pipelines and Alberta energy exports, including Secretary of State Mike Pompeo, Secretary of Energy Dan Brouillette, Secretary of the Interior David Bernhardt and U.S. Trade Representative Robert Lighthizer. Premier Kenney also discussed pipeline issues and new opportunities for expanding trade with the U.S. following the ratification of the Canada-United States-Mexico Agreement.

The Government of Alberta continued to stand up to federal policies that are damaging Alberta's economy with letters from several ministers to their respective federal counterparts. These letters reiterate Alberta's positions on market access, regulatory overstep, and federally imposed climate programs, and outline the actions that should be taken to support the province's people, industries and economy.

Economic Corridors

At the Council of the Federation in August 2019, Premiers agreed to explore the concept of pan-Canadian economic corridors. The Ministers' of Energy and Transportation were tasked with developing a report in response, which includes:

- options available to increase productivity by distributing energy, communications, and economic potential;
- whether there are broad policy changes required to enable ongoing work on this concept;
- a proposal for engaging key partners, including Indigenous communities, in advancing this work; and
- a work plan that outlines next steps and broad timelines for ongoing provincial-territorial work on this issue.

Regular working group meetings with provinces and territories took place to facilitate discussions and gather information. Discussions focused around the potential to establish multi-modal (road, rail, utilities and communications) rights-of-way across country to address geographic, political, social and economic challenges faced by Canada and its regions.

In addition, the Government of Alberta provided a grant of approximately $1.7 million to the University of Calgary Canadian Northern Corridor Research Program to support its research and inform potential advocacy and policy development related to pan-Canadian economic corridors. The research program will conclude in 2024 and focuses on several considerations, including trade, funding, legal and regulatory, organization and governance considerations, as well as social benefits and costs and environmental impacts.

Curtailment

In December 2018, the Government of Alberta moved to temporarily limit crude oil production to match production with takeaway capacity until additional pipelines and rail is available. This was implemented in January 2019. Due to continuing pipeline delays, oil production limits have remained necessary. In August 2019, this resulted in an extension of the policy until December 31, 2020.

During 2019-20, Energy enhanced the production limits to provide industry with more flexibility. For example, government increased the production exemption from 10,000 barrels per day to 20,000 barrels per day, which changed the number of curtailed operators from 29 to 16. Along with this, Special Production Allowances were introduced in October 2019 to allow curtailed operators to increase production above their curtailment limit, if those additional volumes were shipped out of Alberta on incremental rail. In November 2019, it was also announced that all new conventional oil wells spud on or after November 8, 2019, were exempt from curtailment. This exemption would encourage the drilling of new conventional wells, increased investment and the creation of more jobs for Albertans.

Crude by Rail

In February 2020, the Government of Alberta directed the divestment of the crude-by-rail program to the private sector. The Alberta Petroleum Marketing Commission (APMC) was tasked with divesting the crude-by-rail contracts on behalf of government.

The APMC engaged the investment bank CIBC to provide assistance in designing, implementing, and executing the divestment process for APMC. In February 2020, the Government of Alberta finalized agreements to transfer the obligation of the crude by rail program from the Alberta Petroleum Marketing Commission to the private sector. There are many complexities to these contracts that require additional work to have each contract assigned to the new counterparty, and be fully divested.

The crash in commodity prices brought on by COVID-19 just weeks later resulted in delays in assigning some of those contracts.

The contracts cover all aspects of shipping crude-by-rail including rail cars, buffer cars, inspection and delivery fees, railway tolls, terminals, storage tanks, loading at terminals, interconnection, various taxes, customs, cross-border fees, and logistics. The total cost of divestment is $1.5 billion, less than the projected $1.8 billion cost of operating the program. Industry will have direct access to an additional 120,000 barrels per day of takeaway capacity which will help create the market conditions for companies to make positive investment decisions, such as increasing drilling or oil production.

Nobody could have predicted in February the profound and sudden impact the pandemic would have on market conditions and the crude by rail divestiture. However, this is an example of why it was maintained from the outset that private industry is in the best position to be shipping crude by rail, not government.

Key Objective 1.2

Establish the Canadian Energy Centre to respond in real time to misinformation about Alberta's energy industry.

The Government of Alberta established the Canadian Energy Centre (CEC) as an independent provincial corporation under the *Financial Administration Act*. Its mandate is to promote Canada as the supplier of choice for the world's growing demand for responsibly produced energy.

The CEC was established at a time when Alberta's energy sector was under increased public scrutiny from both the investment community as well as a number of well-funded and well-organized anti-fossil fuel groups. To date, these groups have dominated the public discourse in this space; in response, the CEC raises awareness and understanding of Canada's long-term position as a safe, clean, and responsible energy supplier. The CEC website can be accessed at www.CanadianEnergyCentre.ca.

The CEC consists of three units that work together to tell Canada's energy story:

- A rapid response unit to issue swift responses to misinformation about Canadian oil and natural gas.
- A pro-active energy literacy unit that creates original content to elevate the general understanding of Canada's energy sector and help the country take control of its energy story.
- A data and research unit that centralizes and analyses data targeting investors, researchers, and policy makers.

Prior to establishment of the CEC, the sum of $4.3 million was spent by Communications and Public Engagement in 2019-20 to advocate for the province's energy industry. This included development and initiating high profile, multi-faceted marketing campaigns in Ottawa and British Columbia's Lower Mainland, as well as building and management of bilingual websites and social accounts - urging federal re-approval of the Trans Mountain Pipeline expansion and the rejection of *Oil Tanker Moratorium Act* and *Impact Assessment Act*. Also included in this amount is research to inform the strategy of the Canadian Energy Centre. Since the establishment of CEC, a sum of $1.8 million was spent on CEC activities in 2019-20.

Key Objective 1.3

Launch a public inquiry into foreign sources of funds behind the anti-Alberta energy campaigns.

In July 2019, the government launched an independent public inquiry, under the *Public Inquiries Act*, into the existence of a well funded foreign campaign aimed at discrediting Alberta's energy sector - a campaign which is alleged to have robbed Albertans of billions of dollars of lost revenues and thousands of jobs. Steven Allan, a Calgary forensic and restructuring accountant with 40 years of experience, was appointed commissioner to lead the inquiry.

Phase I of the independent inquiry included information gathering through paper review, interviews and completing additional research. In September 2019, the inquiry also launched a public inquiry website, AlbertaInquiry.ca, to allow individuals and organizations to support the inquiry.

The commissioner's initial findings have shown that additional time and work is required to complete the final report. This extension will allow the commissioner to fairly and justly complete the inquiry process and follow up on the materials discovered to date. Due diligence cannot, and will not, be sacrificed on an issue this important to the future of our province and country.

The cost of the public inquiry activities for 2019-20 were $1.5 million.

Key Objective 1.4

Create an investment climate that supports the development of energy resources in the province.

Government has undertaken numerous initiatives during 2019-20 to support Alberta's energy investment climate. In addition to other government initiatives such as reducing the corporate tax rate, reducing red tape and eliminating the carbon tax, many Energy initiatives detailed in this annual report support the industry investment climate including market access (key objective 1.1), methane emissions (key objective 1.4), expanded natural gas markets (key objective 1.5), value added opportunities (key objective 1.6), LNG market opportunities (key objective 1.7), electricity (key objective 1.8), liability management (key objective 2.1), and the AER review (key objective 2.3).

Royalty Guarantee Act

To increase investor confidence and assure investors making long-term oil and gas investments in Alberta that the rules will not change, the department passed the *Royalty Guarantee Act*. The *Act* guarantees that the royalty structure in place when a well is drilled remains in place for at least 10 years. The *Act* also guarantees that for a period of at least 10 years, the current royalty structure will remain in place to provide flexibility for government and industry to adjust to market changes and technology advancements, including the ability to make regular required adjustments, such as setting monthly par prices and provide incentives, when appropriate.

The *Act* also confirms that the transition to the Modernized Royalty Framework, for wells drilled on or before December 31, 2016, will occur as planned in 2026.

The key challenge faced by the *Royalty Guarantee Act* initiative was to balance desired outcomes to support the policy objectives of investor certainty, clarity, and stability, while preserving flexibility of the Crown to administer and manage the resource royalty system, respond to changing market conditions and technology, and maintain industry flexibility. To this end, the approach to provide a guarantee that no major restructuring of the hydrocarbon royalty system for a period of 10 years has achieved the desired goal of committing to guarantee under law while maintaining flexibility to make necessary adjustments to the royalty regime for administration, to adjust to market and technology changes, or to simplify or streamline cost calculation, processes, reporting or other similar requirements as part of Red Tape Reduction.

Technology Innovation and Emissions Reduction (TIER)

Energy supported the Ministry of Environment and Parks in the development and implementation of the TIER Regulation, which came into force on January 1, 2020 replacing the Carbon Competitiveness Incentive Regulation. The Ministry of Energy aided, through analysis and advice, Environment and Parks' effort to establish a greenhouse gas emissions management equivalency agreement with the federal government, which Canada agreed to in December 2019. The development of TIER highlights the importance of Alberta maintaining its regulatory jurisdiction and avoiding potentially costly duplication of provincial and federal regulations.

For more information on TIER, visit www.alberta.ca

Methane Emissions

Energy led a multi-stakeholder approach to develop a cost-effective methane reduction initiative in Alberta that targets a 45 per cent reduction in methane emissions by 2025. By utilizing the multi-stakeholder approach, industry supported the initiative by also adopting early action measures through the implementation of technology in advance of the regulation. These actions contribute to energy development while supporting environmental protection.

Alberta's methane regulations are made up of:

- Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting; and
- Directive 017: Measurement Requirements for Oil and Gas Operators and Alberta's Methane Emission Reduction Regulation.

Alberta's methane regulations were designed to aid in the achievement of equivalency with federal methane requirements. Both federal and provincial rules took effect in January 2020. This means that producers needed to adhere to two sets of overlapping methane reduction rules.

A preliminary agreement with federal government is a major step toward providing Alberta's oil and gas industry a single set of strong rules to reduce methane emissions and protect the environment.

Without this agreement, federal rules would remain in effect in the province, meaning producers would need to adhere to two sets of overlapping methane reduction rules. Now, the process to stand down federal regulations in Alberta can begin, allowing the province to build on an already excellent history of reducing emissions utilizing local expertise.

This prelimary agreement follows several years of negotiations and confirms Alberta's regulatory framework will achieve the same emissions reduction as the federal regulations by 2025. The preliminary agreement will require a legislated review process and approval by federal cabinet. This includes Environment and Climate Change Canada (ECCC) posting the preliminary agreement for a 60-day comment period. After the responds period to the public's comments, ECCC will finalize the agreement with an order in council.

During the review period, the federal regulations will remain in effect in Alberta. Once the federal order in council is approved, the regulation will no longer apply in the province.

Clean Fuel Standard (CFS)

Energy supported Environment and Parks in engaging with the federal government on the proposed Clean Fuel Standard, a new regulation to decrease the carbon intensity of fossil fuels used in Canada by 30 million tonnes of CO_2 emissions annually, by 2030. The proposed regulatory approach is for liquid fossil fuel types, including gasoline, diesel, kerosene and light and heavy oils.

Energy has supported Environment and Parks in conveying larger concerns over potential impacts of the CFS to emissions intensive and sectors, lack of early impact analysis work, and the breadth of potential carbon leakage.

As CFS is a federal initiative, Alberta continues to focus on encouraging an outcome that produces efficient policies that encourage investment and avoid additional unintended consequences for Alberta's oil and gas sector.

Environmental Social Governance (ESG)

A key priority for the Government of Alberta is to inform the world about how Alberta produces energy with among the world's highest environmental, social, and governance (ESG) standards. This is a significant reason

What is Environmental Social Governance (ESG)?

Environmental, social and governance (ESG) broadly refers to the three factors to consider when measuring the sustainability and ethical impact of an investment. Environmental criteria consider how a company performs as a steward of nature. Social criteria examine how it manages relationships with employees, suppliers, customers, and the communities where it operates. Governance deals with a company's leadership, executive pay, audits, internal controls, and shareholder rights.

Over the last five years, ESG investing has gained prominence and is being used as the lens through which mutual funds, brokerage firms, hedge funds and other investors screen companies for financial risk due to their environmental, social and governance practices.

why Alberta's natural resource economy is vital to the transition to a lower-carbon economy, and will be critical to the post-pandemic economic recovery.

While the performance of Alberta's energy sector ranks favorably when matched against its competitors, the global ESG conversation lacks coherence. Alberta is taking a proactive and systematic approach aimed at restoring confidence in Alberta's ability to remain competitive in a carbon-constrained future, easing ESG divestment pressure and enabling the return of capital investment to the province.

Energy is leading the development of a provincial ESG strategy aimed at strengthening and promoting Alberta's position as a responsible energy producer and attracting investment to its energy sector. Specifically, the department is working to accelerate development and awareness of Alberta's ESG leadership; establishing Alberta's many international offices as centers for advocacy and information about our energy sector; and continuing to hold conversations with the United Kingdom, European Union, and other international audiences to showcase the province's excellent ESG credentials.

Energy has established the ESG Working Group, bringing together a diverse group of stakeholders from across government, industry, finance, and academia to advise government on ESG priorities, create and maintain investment momentum, and ensure strategic alignment of policy and messaging. The ESG Working Group is supported by the ESG Secretariat, housed in Energy, which leads the coordination of ESG work across the Government of Alberta.

Minerals and Metals

Alberta is well-known as a leading jurisdiction for mining energy products beyond oil and gas. As the second largest coal producer and exporter in Canada, due to its high-quality metallurgical (steelmaking) and thermal bituminous coal, the province currently has nine producing coal mines.

Alberta also has the geological potential for non-energy minerals, many of which have been identified as critical and strategic minerals, such as lithium, vanadium, rare earth elements, potash, and titanium. Despite mineral occurrence throughout the province, no metallic mineral mines currently operate in Alberta. Alberta's non-energy mineral production comes primarily from 20 active quarries producing salt, silica sand, limestone, and other industrial minerals. In addition, a small amount of gold production is reported as a by-product of sand and gravel operations.

Energy has been working with the federal and other provincial and territorial governments, through the Mines Intergovernmental Working Group, in developing the federal Action Plan 2020, to help pursue the vision and targets set out in the Canadian Minerals and Metals Plan. Alberta provided input and perspectives into development of the Action Plan and a preliminary version that was launched by Natural Resources Canada at the Prospectors and Developers Association of Canada Convention in March 2020. The Action Plan 2020 includes pan-Canadian initiatives and will help the department advocate for Alberta minerals opportunities, raise awareness of Alberta government initiatives, and position Alberta as a potential mineral supplier and manufacturer along the critical minerals value chains.

The Government of Alberta continues to work with the federal government on this plan towards the final Action Plan 2020, which was scheduled to be approved at the 2020 Energy and Mines Ministers' Conference.

Geothermal Energy

As an emerging sector, developing Alberta's geothermal energy potential presents opportunities to support economic and industrial diversification, transition to renewable energy mix, clean energy growth and innovation, and increase the overall competitiveness of Alberta's economy. Interest in geothermal energy development has increased in Alberta. This is attributed to improved data and information, technology advancements, oil and gas expertise, established supporting sectors, and opportunities for repurposing inactive oil and gas wells sites, existing infrastructure and co-production.

The Ministry of Energy continued to work in collaboration with cross-ministry and provincial agency partners to help geothermal projects navigate through regulatory requirements. The ministry actively worked with proponents on a case-by-case basis to advance potential projects and identify risk-based regulatory pathways.

Geothermal energy development could help diversify Alberta's energy sector. As economic conditions improve, Alberta would expect to see some geothermal projects continue to advance and attract capital investment into the province.

Helium Royalty Rate

There is an increasing global demand for helium, in part because of its use in medical imaging, electronics and space exploration. Industry has expressed interest in exploring Alberta's helium potential. Through engagement with industry, the Government of Alberta identified that the lack of a royalty rate was a barrier to the development of helium deposits in Alberta and worked to increase investor certainty in this area.

A royalty rate of 4.25 per cent was retroactively effective on April 1, 2020 for all wells in Alberta from which helium is recovered. This works to provide clarity needed for investment and ensures a fair return for Albertans. The helium royalty rate has been established through amendments to two regulations: Natural Gas Royalty Regulation, 2009 and Natural Gas Royalty Regulation, 2017. The Helium Royalty Adjustment Factor will be reviewed in five years to ensure it is still competitive and to determine if adjustments need to be made.

Key Objective 1.5

Implement a robust natural gas strategy, including the optimization of the Western Canadian pipeline network and pursuit of opportunities for increased pipeline capacity and markets within Alberta.

Government has prioritized the revitalization of Alberta's natural gas industry by acting swiftly to implement a robust natural gas strategy that includes collaborating with industry to optimize the western Canadian natural gas pipeline network, improving regulatory processes, and enabling the growth of markets within and outside of Alberta.

Energy continues to work with regulators, industry, and other governments to streamline project approvals, grow pipeline access, and help Albertans get full value for their natural gas.

Premier Kenney appointed both an Associate Minister and an Associate Deputy Minister of Natural Gas to oversee a natural gas strategy that will help revitalize the sector and get Albertans back to work.

Natural Gas Engagement

From December 2019 to March 2020, Energy undertook targeted engagements with a broad cross-section of the natural gas sector, Indigenous representatives and municipalities to receive feedback on actions required to revitalize the natural gas sector and expand the natural gas value-chain. This engagement built upon the recommendations received from the 2018 Roadmap to Recovery report and allowed the Department of Energy to prioritize key actions and balance the interests of subsectors with intended outcomes for Albertans.

Industry stakeholders identified a number of remaining Roadmap to Recovery recommendations that are appropriate for industry-led action. The recommendations for government action are to:

- create an aspirational vision for the sector;
- develop markets including expanding the petrochemicals sector;
- improve Alberta's regulatory system;
- improve the federal regulatory system; and
- secure LNG opportunities for Alberta.

Energy converged the full sector around shared outcomes and principles. Potential actions were tested and revised for prioritization and need. During this consultation, Energy advanced a draft, forward-looking vision and core elements of a natural gas strategy aimed at creating jobs and growing Alberta's economy. The vision and strategy are expected to be completed in the near future.

Increasing Access to Storage

In 2019-20, Energy initiated work with TC Energy and industry on recommendation seven of the 2018 Roadmap to Recovery report to increase access to natural gas storage as a bridge to markets. A temporary change to the service protocol governing the Nova Gas Transmission Line system was negotiated with industry to increase natural gas access to storage during times of planned maintenance for the summers of 2019 and 2020, and subsequently approved by the Canada Energy Regulator. Implementation of the Temporary Service Protocol has effectively reduced extreme market volatility and improved investor confidence in the sector.

Shallow Gas Tax Relief

In July 2019, the Government of Alberta announced tax relief for shallow gas producers and municipalities for the 2019 property tax year. Shallow gas producers received more than $23 million in total support extended for this tax relief. In December 2019, the Government of Alberta announced that this tax relief will be mirrored for the 2020 property tax year.

This short-term relief will help shallow gas producers cut costs, protect jobs and remain competitive in the face of economic pressures affecting the natural gas industry, while the province updates the assessment model.

The Department of Energy worked closely with Ministry of Municipal Affairs to help characterize and identify the natural gas producing wells operating in Alberta, and also provided perspectives and analysis on Alberta's natural gas industry and markets. Government will continue to consult with municipalities and industry as it changes the model used to determine the value of assessments, particularly for oil and gas properties. Changes are expected to come into effect in 2021.

Key Objective 1.6

Implement initiatives that support natural gas value chains and value-added processing in the province.

Petrochemical Diversification Program (PDP)

PDP was originally launched in 2016 to enable construction of new and expanded petrochemical facilities in the province by providing royalty credits to encourage companies to build manufacturing facilities that turn ethane, methane and propane feedstock into products that have more value than the raw materials. These more valuable products include plastics, fabrics, fuels and fertilizers. Under the program, approved projects are issued royalty credits once the facilities become operational.

Round One: Two projects were approved under PDP round one. The Canada Kuwait Petrochemical Corporation was approved to receive up to $300 million in royalty credits for its $4.9 billion propane dehydrogenation and polypropylene complex in Alberta's Industrial Heartland. Inter Pipeline Ltd. was approved to receive $200 million in royalty credits for its propane dehydrogenation facility within the company's $3.5 billion Heartland Petrochemical Complex. Updates for these projects in 2019-20 include:

- In January 2020, Canada Kuwait Petrochemical Corporation executed a lump sum Engineering Procurement and Construction contract for the construction of the propane dehydrogenation facility within its integrated propane dehydrogenation and polypropylene upgrading facility. In light of developments related to global oil price declines and COVID-19, in March 2020, Pembina announced its intention to defer spending on development of its PDH-PP facilities until economic circumstances improve.
- Inter Pipeline began construction of the company's Heartland Petrochemical Complex, which includes the propane dehydrogenation project, in early 2018. The construction has progressed significantly in 2019 with the completion of the heavy lift program, mechanical equipment setting, super module assembly and piping erection. The facility is targeting to be operational by the end of 2021. Inter Pipeline has spent approximately $2.2 billion on the Heartland Petrochemical Complex project. Over 150 Alberta based companies and nearly 30 other Canada-based companies are working directly on engineering and construction of the complex project.

Round Two: In October 2019, the government confirmed a $1.1 billion commitment to the second round of the Petrochemicals Diversification Program. Only $150 million of the $1.1 billion committed has been confirmed to date, for two projects, and the government has resumed its consideration of applications submitted to the program:

- Nauticol Energy's Grande Prairie Facility was approved to receive up to $80 million in royalty credits to process natural gas to produce methanol. Nauticol Energy is advancing the development of the project in a sustainable way and has expanded its First Nations outreach. It has selected its project site in a Brownfield area, located its rail yards in an industrial area and is leveraging existing water supply and wastewater infrastructure at International Paper to minimize environmental impacts. Nauticol Energy is also exploring alternative technologies to reduce greenhouse gas emissions and water use. It plans to invest between $2.73 and $3.27 billion for all three phases of the project, and has already invested over $30 million in early stage project development.
- Inter Pipeline's Acrylic Acid and Propylene Derivatives Facility was approved to receive up to $70 million in royalty credits to convert polymer grade propylene to produce acrylic acids and other derivatives. Acrylic acid is a propane derivative material, which is used in paints, absorbent materials such as diapers and other hygiene products.

Both companies are working toward their Final Investment Decisions.

Sturgeon Refinery

Alberta has a binding 30-year commitment to provide bitumen that will be processed into refined products – primarily ultra-low sulphur diesel – and, in return, pay a cost-of-service toll to the North West Redwater Partnership (NWRP).

A significant part of the refinery has been online since November 2017 and it started full commercial operation processing bitumen in early 2020, producing approximately 50 thousand barrels per day of refined products. Delays to achieving full commercial operation were due to the gasifier and hydro processing units.

In April 2020, the Sturgeon Refinery successfully transitioned from primarily processing synthetic crude feedstock to bitumen feedstock and reached commercial operations in May 2020.

Returns for phase 1 of the project will be affected by commodity prices for refined products and feedstock, the potential for a narrow differential between bitumen and light oil and products, final capital cost, and timing of full operations.

APMC has borrowed $439 million from Treasury Board to lend to the refinery, with the commission obtaining 25 per cent voting interest in the NWRP Executive Committee while the loan is outstanding. In addition, APMC has borrowed $342 million from Treasury Board to pay for pre-Commercial Operations Debt Tolls to NWRP.

Each year, APMC reviews the Processing Agreement with NWRP. The Commission uses a cash flow model to determine if the unavoidable costs of meeting the obligations under the NWRP Processing Agreement exceed the economic benefits expected to be received. The model uses a number of variables to calculate a discounted net cash flow for APMC. Those variables include technical variables that arise from the design of the project, such as pricing related variables including crude oil prices (WTI), heavy-light differentials, ultra-low sulphur diesel-WTI premiums, exchange rates, capital costs, operating costs, interest rates, discount rates; and operating performance compared to capacity.

Based on the analysis as at the authorization date of these financial statements, APMC determined the agreement has a negative $2.52 billion net present value, most significantly influenced by two variables, pricing and on-stream factor. The net present value is a snapshot in time and will change with commodity prices.

APMC uses the Government of Alberta budget forecast values for WTI, WCS, condensate and foreign exchange to calculate the net present value. The single largest contributor to the decrease (81 per cent) in the net present value of the contract year-over-year is due to lower forecasted future WTI prices for the life of the refinery and a significant narrowing of the Diesel-WCS spread for 2020 to 2022. The two most impactful pricing variables to the net present value of the contract are forecasted WTI prices and foreign exchange:

- The net present value of the contract has a sensitivity to changes in WTI of +/- $157 million for every dollar change from the WTI forecast.
- The net present value of the contract has a sensitivity to changes in foreign exchange, for every $0.01 the Canadian dollar changes from the forecast there is a +/- $109 million change to the net present value of the contract. If the Canadian dollar weakens in relation to the U.S. dollar, there is a positive impact to the net present value of the contract and, conversely, if the Canadian dollar strengthens in relation to the U.S. dollar, there is a negative impact to the net present value.

The APMC updates the net present value of the Sturgeon Refinery project each year to account for changing variables that impact the calculation.

Key Objective 1.7

Ensure Alberta participates in global liquefied natural gas opportunities.

Alberta's natural gas can help meet the growing global demand for sustainable energy – it is estimated that by 2040 global demand for natural gas will increase by 43 per cent over 2017 levels. Six LNG projects are already operating in the U.S. with another eight under construction. Canada only has one LNG export project currently under construction: LNG Canada, slated for completion in 2025. LNG represents the best opportunity for western Canadian demand growth and diversification, and is regarded as the only option that will make a material difference in western Canadian natural gas markets. Asia Pacific markets represent an attractive opportunity for western Canadian supply as China and other Asian countries are driving strong growth in global LNG demand.

Alberta is exploring ways in which it could leverage financial and other supports through the Alberta Indigenous Opportunity Corporation and the Alberta Petroleum Marketing Commission to advance one or more LNG projects utilizing Alberta natural gas as feedstock. Alberta also continues to collaborate with British Columbia and the federal government to preserve and attract new investment to Canada's LNG sector. This includes regular information sharing, joint meetings with targeted investors and strategizing about how to improve Canada's ability to attract investment dollars to this sector. This ongoing collaboration with British Columbia and the federal government may help advance Canadian LNG projects and secure federal funding support throughout the year.

Key Objective 1.8

Increase certainty in the wholesale electricity market, creating the conditions for future investment in generation and the welcoming of market driven investment in renewable energy generation.

On March 24, 2020, Associate Minister Dale Nally assumed responsibility for overseeing Alberta's electricity sector – in addition to natural gas and petrochemicals. The effective operation of Alberta's natural gas and electricity system is critical to support much-needed economic activity across the province, and to support the province's health care response to the COVID-19 pandemic. By pairing natural gas and electricity together, the ministry can ensure the effective operation and integration of these important parts of the energy system.

Electricity Market Structure

The Government of Alberta provided policy and regulatory certainty to investors and project proponents in Alberta's competitive electricity generation sector by halting the transition to a capacity market and by repealing the legislation to enable continuation of Alberta's existing energy-only market model. An energy-only market is best for Alberta, as it:

- offers structural and administrative simplicity;
- has a proven track record for providing affordable electricity in Alberta;
- has a proven track record for providing a reliable supply of electricity in Alberta;
- is already established and understood by investors, which offers them greater certainty regarding its future performance; and

How an energy-only market works:

- generators are paid for the electricity they produce based solely on the wholesale price of electricity, which fluctuates
- these companies determine the type of generation they produce and the location of facilities

How a capacity market works:

- private power generators are paid through a mix of competitively auctioned contracts which pay their fixed capital costs and revenue from the spot market
- a capacity market requires a government-appointed entity – the Alberta Electric System Operator, in Alberta's case – to plan, approve and administer the contracts to buy the capacity needed to meet expected demand

- is supported by the majority of electricity stakeholders, including consumer groups.

Affirmation of Alberta's energy-only electricity market provided investors the stability they were seeking to develop new generation projects, both natural gas-fired and renewable energy, resulting in several major wind project announcements and the acceleration of projects to reduce coal consumption through co-firing or converting to natural gas.

With the return to the energy-only market, government initiated three reviews to explore potential enhancements of the market:

- a review of the mandates and roles of the electricity agencies;
- a review of market power mitigation policy; and
- an Alberta Electric System Operator (AESO)-led review of the pricing parameters in the wholesale market.

The market power mitigation policy review was completed in April 2020 and it was concluded that the existing framework is sound.

The Ministry of Energy will also be tracking the reduction of red tape in the AESO, AUC and Market Surveillance Administrator as these agencies are key components of Alberta's electricity system and resource development. These agencies will be developing work plans related to their red tape reduction efforts.

Renewable Electricity Generation

Renewable energy is defined as energy sources that can be naturally regenerated within a human lifespan and in Alberta they include wind, solar, hydroelectricity, geothermal, biogas and biomass.

Renewable electricity developers have demonstrated that they can compete in Alberta's electricity market, as proven by the many new project announcements. Alberta's electricity market has seen more than $1 billion dollars of announced new investment in wind and solar generation projects since August 2019. This would represent more than 1,110 megawatts of new renewable generation connected to Alberta's grid. When underway, these projects will result in approximately 70 permanent jobs and 1,200 temporary construction jobs. This has been driven by Alberta's recent return to an energy only market and government's commitment to TIER, which encourages renewables. Without providing subsidies, Alberta will continue to reduce barriers to renewable electricity development.

Government discontinued the Renewable Electricity Program (REP) in early 2019 to focus on market-driven renewable electricity development. As the prior REP contracts were signed in good faith by private electricity developers, they remain in effect, and are being closely monitored for compliance by the Alberta Electric System Operator. The status of these contracts is reported annually to the Minister, as required by legislation. Of the 1,360 MW that were contracted under the REP, three projects have achieved, or are close to achieving, commercial operation and have with a combined capacity of 336 MW.

Regulated Rate Option (RRO) Rate Cap Program

The RRO rate cap introduced by the previous government in 2017 was intended to mitigate the regulated electricity price fluctuation expected during the change to a capacity market system. As government was not proceeding with the capacity market system, the RRO rate cap was no longer necessary and was cancelled effective December 2019.

During the 2019-20 fiscal year, the rate cap was triggered every month until November 2019. In the two years that the program was operating, the cap cost the province $108 million. If the program had continued to its legislated completion date of May 31, 2021, the total estimated cost of the program was estimated to be $303 million. Cancelling this program saved Albertans an estimated $195 million.

Red Tape Reduction

Energy took the following actions in 2019-20 to reduce red tape in the electricity market:

- Removed the unnecessary burden of requiring legislation to be passed for hydroelectric projects which have already passed all regulatory requirements.
- Repealed the unnecessary *Small Power Research and Development Act* and its regulations prior to its June 30, 2020 expiry, as the legislation had fulfilled its program objectives and obligations under the related contracts, which have concluded.
- Dissolved the Transmission Facilities Cost Monitoring Committee, which was responsible for reviewing records relating to the cost, scope and schedule of transmission projects forecast to cost more than $100 million, in December 2019, due to the decline of larger transmission projects in the near future.

Additional Achievements

Carbon Capture and Storage

The Government of Alberta committed $1.24 billion, from 2010-11 through to the end of 2025, to two carbon capture and storage projects: the Shell Canada Limited-operated Quest project and the Alberta Carbon Trunk Line. Combined, these two projects will capture and permanently store approximately 2.76 million tonnes of carbon dioxide each year –roughly equivalent to annual emissions from 600,000 vehicles.

The Quest project achieved commercial operation in mid 2015 and has been successfully capturing over one million tonnes of carbon dioxide annually from the Scotford Upgrader and permanently storing it underground in a deep saline aquifer.

In early May 2020, the Alberta Carbon Trunk Line project achieved commercial operation. The fully operational Alberta Carbon Trunk Line is an integrated carbon capture and storage project that captures carbon dioxide from the North West Redwater Partnership Sturgeon Refinery and the Nutrien Inc. fertilizer facility and transports it through a 240-kilometre pipeline to use for enhanced oil recovery in Central Alberta. The Alberta Carbon Trunk Line project is anticipated to capture approximately 1.68 million tonnes of carbon dioxide annually, and the pipeline has been designed to transport up to 14.6 million tonnes of carbon dioxide each year.

Throughout the year, the department continued to monitor, administer and ensure compliance as per the funding agreements for these projects, including:

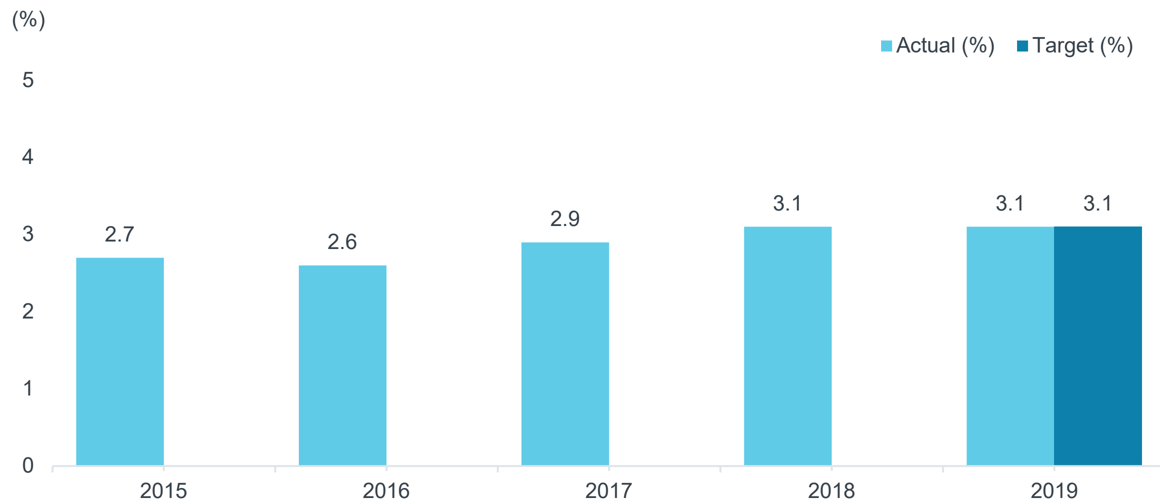
- Administration of an injection payment for carbon dioxide sequestration and levy into the Post-Closure Stewardship Fund in support of the Quest project.
- Third-party certification of carbon dioxide sequestered. This process provides confidence in the mass of carbon dioxide sequestered and supports the Post-Closure Stewardship Fund levy payment.
- To date, the Post-Closure Stewardship Fund has collected four annual injection levy payments from the Quest project. This levy helps provide for future monitoring, measurement and verification of carbon capture and storage sites by the Government of Alberta, after carbon capture and storage operations cease and the government assumes liability for any stored carbon dioxide.

In 2019-20, the department approved Enhance Energy Inc.'s Monitoring, Measurement and Verification Plan for its carbon dioxide enhanced oil recovery operation at Clive, Alberta as part of the Alberta Carbon Trunk Line project. The department also continued its review of the current Post-Closure Stewardship Fund rate, and initiated its review of the Quest project's latest versions of its Monitoring, Measurement and Verification Plan and Closure Plan.

The ministry is taking many of the program management best practices introduced in the Carbon Capture and Storage Funding Program and applying them to other new programs or initiatives through its program design, monitoring and implementation continual improvement processes.

Performance Measure 1.a: Alberta's Oil Sands Supply Share of Global Oil Consumption

Target: 3.1 per cent of global oil consumption is supplied by Alberta's oil sands.



Sources: Alberta Energy Regulator; International Energy Agency[i]

Discussion of Results

Development of Alberta's oil sands, and its role in the global energy mix, is a highly complex system, in which policy must both balance multiple priorities and adapt to changing global dynamics.

There are several levers available to the Government of Alberta, which indirectly impact the results of the measure. Key levers are the fiscal and royalty regimes, which directly act to incent industry's resource development activities, while ensuring that Albertans receive direct financial benefits in the form of taxes and royalties. In addition, there are other government policies that influence industry performance, and therefore oil sands production levels, including promotion of market access, intergovernmental relations, energy research and development, and environmental regulations.

The 2019 supply share met its target of 3.1 per cent. The rate of global year-over-year consumption increased by 0.7 per cent from 99.1 million bbl/d in 2018 to 99.8 million bbl/d in 2019. While the growth rate of Alberta's total crude bitumen production from 2018 to 2019 was lower than the growth rate that took place from 2017 to 2018, the growth rate of global oil consumption also slowed down during this time period.

Total crude bitumen production in Alberta increased by about 1.8 per cent from 2018 to 2019, from about 3.05 million barrels per day (bbl/d) to about 3.10 million bbl/d. The relatively small overall year-over-year increase in bitumen production was due to the increase in the mined production, which went up by about five per cent from 2018 to 2019. On the other hand, the overall in-situ production declined by about two per cent from 2018 to 2019, primarily due to insufficient takeaway capacity. From 2018 to 2019, the share of mined production within the province's total crude bitumen production profile went up from 48 per cent to 50 per cent, while the share of in-situ bitumen went down from 52 per cent to 50 per cent. In 2019, both mined and in-situ bitumen production was at about 1.55 million bbl/d, with mined production being marginally higher.

Overall, the significant slowdown in Alberta's bitumen production rate of growth from 2017-18 to 2018-19 was due to the lack of advancement in additional egress. Pipelines and rail did increase through 2019 by 71,000 barrels per day, through debottlenecking projects and additional rail contracts; however, this was still not sufficient for meeting Alberta's market access requirements. The Government of Alberta's curtailment policy aligned to these increases to ensure that Alberta's production and storage were managed throughout the year.

[i] For more information, see the Performance Measure and Indicator Methodology section on page 81.

Outcome Two

Effective, efficient stewardship and regulation of Alberta's energy and mineral resources

What it means:

The ministry will improve the clarity and efficiency of Alberta's energy regulatory system, while modernizing legislation and regulations to restore the competitiveness of the Alberta energy sector, win back the confidence of investors and create jobs. A strategic and integrated system approach to responsible resource development balances the overall environmental, economic and social outcomes for the benefit of Albertans while ensuring Alberta has a predictable regulatory environment that is attractive to investors and does not include unnecessary red tape.

Key objectives to support the achievement of this outcome include:

- 2.1 Lead efforts to review the liability management framework and the process for well and facility abandonment and reclamation in Alberta, ensuring liabilities are covered without discouraging new investment.
- 2.2 Collaborate with other ministries to establish a balanced and sustainable approach to resource management to manage the combined or cumulative effects of resource development, including regional planning.
- 2.3 Optimize regulation and oversight to ensure the efficient, effective, and environmentally responsible development of Alberta's energy resources through the Alberta Energy Regulator (AER).
- 2.4 Enhance regulation and oversight of Alberta's utilities, through the Alberta Utilities Commission (AUC), to ensure social, economic and environmental interests of Alberta are protected.
- 2.5 Audit the financial losses of the power purchase agreements held through the Balancing Pool.

Key Objective 2.1

Lead efforts to review the liability management framework and the process for well and facility abandonment and reclamation in Alberta, ensuring liabilities are covered without discouraging new investment.

Along with Environment and Parks, the AER, industry and Albertans, Energy continued to address the existing liability challenges in energy development during the worst economic downturn in the province's history. These liability challenges include company insolvencies, unpaid surface rentals to landowners, unpaid municipal taxes, a growing inventory of orphan wells, and other issues associated with the historically low price of oil and the shock of a world health pandemic. This included addressing the safety of inactive and decommissioned oil and gas sites by reviewing the existing upstream oil and gas liability management system, and extending a loan for the Orphan Well Association (OWA) to speed up work to clean up oil and gas sites.

Liability Management Framework

The Liability Management Framework review was focused on protecting Albertans and the environment while ensuring Alberta remains a competitive place to invest. The review aimed at improving the management of historic, current and future liabilities associated with the full life-cycle of upstream oil and gas development. Subject matter experts and key stakeholders provided valuable input into the framework, which helped inform policy discussions and operational changes.

In March 2020, the Government of Alberta approved some key statutory changes that enabled the Orphan Well Association to better manage and accelerate the clean-up of wells and sites across the province that do not have a responsible owner.

- The government passed the *Liabilities Management Statues Amendment Act,* which includes amendments to the *Oil and Gas Conservation Act* and the *Pipeline Act,* to improve the OWA's ability to efficiently and effectively manage financial, safety and environmental risks associated with orphan wells. The improvements are about increasing efficiencies, resulting in job creation and more effective orphan site management, while ensuring a responsible, sustainable oil and gas industry in our province for generations to come.
- The *Liabilities Management Statues Amendment Act* clarifies the OWA's ability to enter into agreements with producers to help site closures; ensure that oil and gas resources are not prematurely abandoned; and to exert more financial control to manage sites that may become orphaned, as well as sites that are already in the OWA's orphan inventory. Subsequent changes to the Orphan Fund Delegated Administration Regulation provided additional detail and clarity regarding the OWA's ability to optimize the use of the orphan funds to better manage and continue to reduce the orphan site inventory.

Orphan Well Loan Program

In March 2020, the government announced its first step in "A Blueprint for Jobs", which was developed to bring jobs and investment back to Alberta. It was announced that the province has extended the OWA loan by $100 million to stimulate the economic activity and create an additional 500 direct and indirect jobs. The $100 million loan is an extension to the interest-free loan that Alberta government provided the OWA in 2017 for $235 million.

The OWA is an industry-funded organization that works to close sites that no longer have a viable operator. This involves removing equipment, decommissioning wells and reclaiming and remediating the sites. This investment will be complete by April 2021.

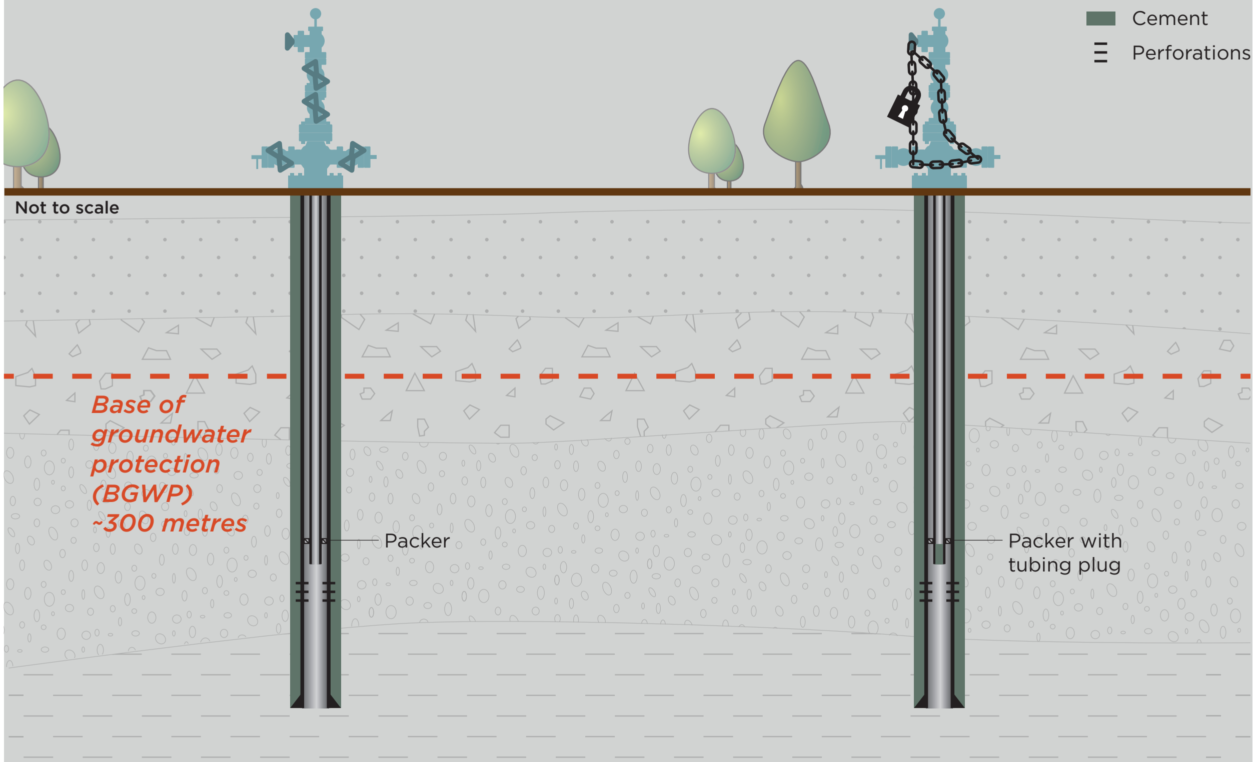
Within fiscal 2019-20, $68 million was advanced to the OWA under the initial loan of $235 million; bringing the total paid out to $218 million. The final quarterly advance of the original $235 million was made on April 1, 2020. The money received from industry through the annual Orphan Fund Levy is used by the OWA to repay the loan. As of January 2020, the OWA has repaid $23.6 million.

As of March 31, 2020, the program has spent approximately $134.4 million and reported the following results from its effort to address the growing inventory of orphaned sites:

- a total of 1,334 wells abandoned;
- 1,587 pipelines decommissioned; and
- 474 sites reclaimed.

Well Status and Activity Definitions

Wells can be in any state: inactive, suspended, abandoned, or even producing. A well is considered orphaned when a licensee becomes defunct without having properly abandoned the well and reclaimed the well site. If this happens, the Alberta Energy Regulator (AER) orders anyone who benefits from or has a legal interest in the well to abandon and reclaim it. If there is no responsible party, the AER deems the well and associated sites to be orphaned. The Orphan Well Association then takes over the care and custody of the infrastructure and sites.

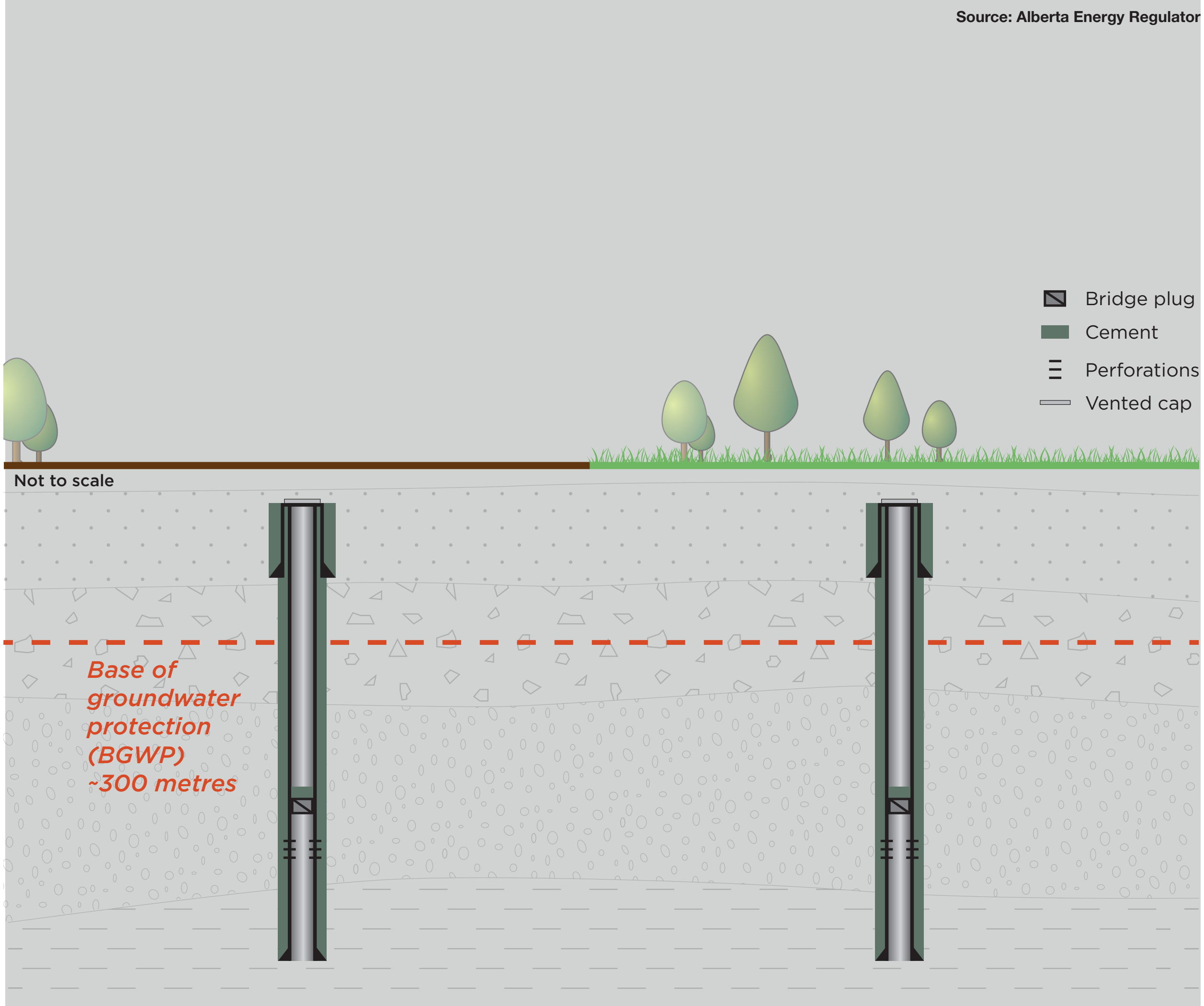


Inactive

An inactive well is one that has not produced oil or gas, injected fluids, and disposed of waste for 6 or 12 months, depending on how the well is classified for risk. An inactive well must be suspended in accordance with the AER's Directive 013: Suspension Requirements for Wells.

Suspended

Suspended wells also are not producing oil or gas, injecting fluids, and disposing of waste. However, these wells have been suspended to meet the public safety and environmental protection rules in Directive 013. Wells can remain suspended until a company determines that the well is no longer needed for energy development and can be abandoned.



Abandoned

Wells are abandoned when they are no longer needed for energy development. Directive 020: Well Abandonment details strict rules that ensure that the well is in a safe and secure state. Although they don't pose a significant risk to the environment or public, leaks are possible. If a leak happens, the company, which is responsible for repairing it, must notify the AER immediately.

Reclaimed

Once an energy project has been properly closed and abandoned, a company may begin remediating and reclaiming the site. Companies must return the disturbed land to a state comparable to the state it was in before development; they will always remain responsible for any infrastructure left beneath the surface.

Companies must clearly demonstrate that all site issues—for instance, ensuring that any contaminated soil meets Environment and Parks remediation criteria—have been addressed. The AER audits a varying number of sites each year based on different risk factors. The AER will also respond to all complaints about site reclamation.

Area-Based Closure Program

The area-based closure program encourages companies to work together in project areas to close oil and gas infrastructure and sites more efficiently and effectively. Through the voluntary program, participants may commit to a closure spend target in exchange for program incentives. Pilot programs have shown efficiencies gained through collaboration and economies of scale can have cost savings of up to 40 per cent. More closure work can be completed with the same closure budget using the program principles to help reduce liabilities associated with inactive sites.

In 2019, 44 companies committed to spend nearly $244 million, which represented four per cent of their deemed inactive liability from Directive 011- Licensee Liability Rating Program: Updated Industry Parameters and Liability Costs. An additional 12 companies participated in the collaborative-only components of the program, using the mapping functionality available through the AER's Onestop system which allowed licensees to still collaborate together to save money by sharing the costs of working in the same area, even if they did not commit to annual closure spend. These licensees did not commit to a closure spend target. As of the end of fiscal 2019-20, all 13 participating companies that completed their reporting were successful in meeting their four per cent spending commitment. Over the upcoming months, the balance of companies will complete their 2019 closure reporting.

Annual Wells Decommissioned: Performance Indicator 2.e

5,994 number of wells were decommissioned in 2019. An increase in year-over-year in the number and per cent of wells decommissioned is a positive signal that progress is being made. The increase of annual wells decommissioned can be attributed to AER's Area Based Closure initiative and the OWA's Orphan Well Loan Program.

The decommissioning process is part of the closure process and involves the company removing surface equipment and sealing the well to prevent the well from impacting the environment.

Year	2015	2016	2017	2018	2019
Number of wells decommissioned and left in a safe and secure condition	4435	3518	5392	5301	5994
Per cent of wells decommissioned and left in a safe and secure condition compared to inactive well population	5.1	3.8	5.7	5.6	6.4

Source: Alberta Energy Regulator[i]

Key Objective 2.2

Collaborate with other ministries to establish a balanced and sustainable approach to resource management to manage the combined or cumulative effects of resource development, including regional planning.

Decisions on energy and mineral resource development require consideration of economic, environmental and social outcomes, and that consultation and engagement are key to mitigating risks. The ministry made progress on several longer-term initiatives in 2019-20.

[i] For more information, see the Performance Measure and Indicator Methodology section on page 85.

Integrated Resource Management

The Government of Alberta approaches natural resource management from an integrated and systems approach. Cumulative impacts of energy resource development are examined in relation to economic, environmental and social interests.

The Integrated Resource Management System (IRMS), Land-use Framework and associated planning processes were designed to seek the information required for decision-making around energy resource development. The ministry continues to work on engagement to support informed decisions through the Engaging Communities Practice Group, collaborating with other ministries through IRMS and conducting engagement sessions with Indigenous communities, industry participants and other stakeholders.

In 2019-20, the Ministry of Energy worked collaboratively with cross-ministry partners and external stakeholders at all levels to advance the department's responsible resource development and stewardship objectives, and to ensure the opportunity costs and benefits of land management decisions were well understood. A challenging part in developing these objectives for the province is reconciling various perspectives to clearly define what is in the public interest. It involves exploring the benefits of continued development while conserving resources or meeting other societal expectations. Conducting analysis, and sharing data and information are key mechanisms to achieving these objectives.

Conservation Area Implementation

Energy completed the compensation and cancellation of the remaining Crown mineral agreements that were fully or partially impacted by the creation or expansion of three parks in the South Saskatchewan Region. Energy paid $957,241 in compensation in 2019-20 to cancel 2,094 hectares of incompatible Crown mineral rights held within 25 Crown mineral agreements. The total area protected by the establishment of Castle Provincial Park and High Rock Wildland Provincial Park, and the expansion of Don Getty Wildland Provincial Park (the three parks where Crown mineral agreements were cancelled in 2019-20) is 60,110 hectares.

Caribou Sub-Regional Task Forces

The caribou sub-regional task forces were announced in August 2019, with a mandate to provide recommendations on land use planning at the sub-regional scale, including caribou recovery actions. Multi-stakeholder working groups are also active and held several multi-day planning sessions. Energy provided support in the planning sessions by representing the department's responsible development mandate and providing reliable information about Alberta's Crown mineral resource management systems and industry activities.

Key Objective 2.3

Optimize regulation and oversight to ensure the efficient, effective, and environmentally responsible development of Alberta's energy resources through the Alberta Energy Regulator (AER).

The Alberta Energy Regulator (AER) is responsible for regulating the life cycle of oil, oil sands, natural gas and coal projects in a manner that protects public safety and the environment. In 2019-20, the AER's operating costs totalled $264 million, which included $28 million in severance costs due to restructuring. AER energy regulation activities are fully funded by industry.

AER Review

The AER regulates:

- More than 164,000 operating wells
- More than 436,000 km of pipelines (plus inspection/ incident response support for 12,000 km regulated by the Alberta Utilities Commission)
- About 21,000 gas facilities
- More than 30,000 oil facilities
- Eight operating oil sands mines
- More than 70 thermal/enhanced in situ projects and 240 primary recovery in situ projects
- 36 thermal in situ oil sands operations
- Four active bitumen upgraders
- Nine producing coal mines
- Four coal processing plants

In 2019-20, the Government of Alberta initiated a review of the Alberta Energy Regulator to identify enhancements to its mandate, operations and governance operations to ensure that Alberta remains a predictable place to invest and a world leader in responsible resource development.

In October 2019, a series of workshops were hosted by the Government of Alberta to solicit input from stakeholders and communities, which included industry, industry associations, investors, municipalities, municipal associations, environmental and non-government organizations, academics, think tanks, landowners and Indigenous representatives. Albertans also were able to provide feedback via the Government of Alberta website between September 6 and October 14, 2019.

Feedback and suggestions covered various aspects of the AER's effectiveness. Notable feedback included:

- an overhaul of the AER is not needed;
- refocusing and moderizing processes will help the AER function effectively and efficiently; and
- unclear and inflexible processes must be clarified and updated.

As a result of the review, a number of steps were taken to improve the AER's mandate, governance and systems operation. In the fall of 2019, an interim board was appointed that consisted of public servants and individuals with oil and gas expertise. The board provided direction on restructuring, reviewed the industry levy that funds the AER, established a recruitment process for a new Chief Executive Officer (CEO) and updated the mandate and roles documents for clarity and proper oversight.

In April 2020, a permanent CEO and board of directors were appointed to help stabilize its governance and leadership. The new board of directors will focus on increasing stability within the AER, help the energy industry operate during COVID-19 pandemic and the current challenging economic conditions.

Integrated Decision Approach

The department collaborated with the AER to develop policies to support the full implementation of the Integrated Decision Approach (IDA). The IDA is based on the concept of integrated, risk-informed life cycle regulation of energy development, including one application, one review, and one decision. The AER continued to implement the IDA for energy development by using a new technology known as OneStop. OneStop aims to dramatically reduce allocation processing timelines and wait times for companies. OneStop streamlines baseline review of applications for lower risk activities and forwards applications for higher-risk activities for a more detailed assessment. By 2022, all application processes will have moved to OneStop.

In 2019-20, the AER delivered public lands dispositions and well licensing through OneStop and made enhancements to areas already implemented, such as pipeline licensing and reclamation certificates. These enhancements support efforts to enhance regulation and oversight of energy resource development and increases the effectiveness of AER decisions by focusing on what matters the most to Albertans and making the AER administrative processes more efficient. The approach also offers more transparency, allowing Albertans to see the whole picture of a proposed energy project.

During the 2019-20 fiscal year, significant IDA implementation and OneStop functionality was delivered, including:

- processing of public lands and well licensing applications received through OneStop;
- data sharing between the AER and the Government of Alberta on public lands; and
- implementation of the IDA for the majority of applications, submissions and notifications received.

This functionality enabled:

- the ability to collect lifecycle data to inform decision making;
- increased decision/investment certainty and enhanced transparency;
- elimination of duplicated work;
- increased access to data; and
- increased consistency in risk-informed decision-making.

As a result of the implementation of IDA and the increasing functionality of OneStop, the following progress has been achieved:

- 80 per cent of applications are processed under IDA
- 50 per cent reduction in application timelines under IDA
- over 55,000 applications processed through OneStop since 2016
- 55 per cent automation of routine applications through OneStop
- over 70,000 submissions and notifications processed through OneStop annually

The AER continues to address challenges with the implementation of the IDA, including change management, communications, sustainment of the transformation, and multi-year funding.

Regulatory Efficiency Initiative

The Regulatory Efficiency Initiative (REI) was launched by the AER to improve application timelines, ensure modern and effective regulations and continue to transform how the AER operates. The REI is driven by the intent of minimizing regulatory burden to industry, enhancing our existing regulatory requirements and changing existing technical and process requirements, all of which contribute to Alberta's competitive advantage.

Significant REI achievements to modernize regulations in 2019-20 included changes to Directive 081 - Water Disposal Enhancements Project to encourage thermal in situ oil sands operators to use alternative water sources over high-quality nonsaline sources and minimize the need for variances for water-long schemes and for schemes using alternative water sources. Water-long schemes have more water coming back to their processing facilities than the volume of steam they inject to recover oil. The excess water produced cannot be recycled into steam and needs to be disposed.

The AER identified and prioritized a number of projects for implementation under the Regulatory Efficiency Initiative, within an 18-to-24 month period, for completion to reduce regulatory burden across the regulatory lifecycle using a risk-informed approach. As of March 31, 2020, the AER had completed 27 REI regulatory projects since it was developed in January 2018.

The REI focused on six key regulatory areas:

- OneStop and the Integrated Decision Approach
- Statement of Concerns Streamlining and Applications Timelines
- Area Based Closure
- AER/Aboriginal Consultation Office Streamlining Routine Applications
- In-Situ Project Disposition
- Oil and Gas Conservation Rules Modernization

Since August 2019, the AER has integrated its REI project work within the larger framework of the Government of Alberta's red tape reduction work. The AER will be refocusing the efforts of the Regulatory Efficiency Council in 2020 and leveraging the learnings from the past year to ensure best results for 2020.

The AER is also working closely with other ministries on potential legislative reforms for government consideration based on internal AER analysis and feedback provided by key stakeholders. This feedback includes subtle changes to current practices that would streamline the regulatory system, provide more certainty to operators, and decrease application timelines.

Additional regulatory improvements were also made to the Aboveground Reusable Bladders with Structural Frame System. Hydraulic fracturing operators in Alberta lacked clarity on AER's expectations with respect to the use of alternative storage options for above ground walled storage systems.

In December 2019, the AER communicated to hydraulic fracturing operators that the usage of above ground walled storage systems that utilize a reusable bladder are allowed provided they adhere to the corresponding approval processes.

AER's also modernized Directive 054. The Directive was originally released almost two decades ago with the goal of becoming an effective instrument for in situ information reporting, surveillance, and performance tracking. As in situ technologies have evolved and understanding of the sector has grown, in situ resource development has become a routine and low risk activity. As a result, Directive 054 has largely become ineffective at managing in situ performance and risk, and does not justify the burden to in situ operators. The AER has alternative methods for collecting most of the information found in Directive 054 through other regulatory instruments. The benefits to updating this Directive included:

- cost savings for in situ operators through the elimination of overlapping information submissions across other directives, which has saved an estimated average of 450 hours per operator; and
- reduced burden on industry through a reduction of 155 requirements that were deemed not critical, and removed from the Directive.

Regulatory Enforcement and Compliant Inspections: Performance Indicator 2.c

The Alberta Energy Regulator tracks the per cent of inspections that did not result in enforcement actions, and the percent of inspections in compliance with regulatory requirements, reflecting the AER's ability to achieve its mandate through inspection (prevention) activities. Inspections allow field inspectors to determine if regulatory requirements have been met and provide an opportunity to work directly with companies to bring them back into compliance. Inspections that result in noncompliance are triaged and assessed based on the AER's Integrated Compliance Assurance Framework to determine the best course of action to correct the noncompliance. Based on the results of the triage assessment an investigation may be warranted. The investigation may result in an enforcement action. An enforcement action is defined as an exercise of statutory power of the regulator in response to a finding of significant noncompliance.

	2015-16	2016-17	2017-18	2018-19	2019-20
Regulatory Enforcement: Per cent of inspections that did not result in enforcement actions	99.8	99.6	99.7	99.8	99.6
Compliant Inspections: Per cent of inspections in compliance with regulatory requirements	75	76	76	76	78

Source: Alberta Energy Regulator[i]

The trend of inspections not resulting in enforcement has been consistently at 99.7 per cent for the past 5 years. In 2019-20, the percent of inspections with a compliant inspection result was at a five-year high, at 78 per cent. In 2019-20, the AER conducted 9,625 field-based inspections, of which 7,451 resulted in a finding of compliance. The inspections resulted in the issuance of 42 enforcement actions, as follows:

- 25 orders;
- 1 prosecution; and
- 16 warning letters.

Initial inspections are selected based on an enterprise management approach to defining and applying risk as well as the predetermined level of risk that an activity may pose to health and safety, the environment, resource conservation, and stakeholder confidence in the regulatory process, including public and political influences. Historical operator compliance is a component of the risk-based site selection process.

The AER places higher priority on reactive work, such as releases or complaints. The amount of reactive work can significantly impact the reported result for this indicator because the nature of the work is unplanned and has a high chance of resulting in enforcement action. This kind of work required greater inspector attention and leaves less ability to conduct proactive initial inspections.

AER continues to develop innovative approaches, programs, and processes to manage these liabilities and risks while supporting economic development in the province. The AER's approach to managing liability was built to balance multiple interests: environmental protection, public safety, landowner interests, investment, royalties, jobs, and market volatility.

Water Use

The AER reports company-specific information on the amount of water used for in-situ, mining, hydraulic fracturing and enhanced oil recovery operations annually, and provides contextual information concerning the major drivers of water use during energy extraction within each of these sectors since 2017. The water use report provides water availability, water allocation and water use by the oil and gas industry in a transparent and accessible way for the public, stakeholders and industry. The report aims to influence industry behavior and innovation for water use without additional regulation.

[i] For more information, see the Performance Measure and Indicator Methodology section on page 84.

In 2019-20, the AER released its water use report for 2018 data on the AER website at www.aer.ca. The addition of water availability information provided stakeholders and the general public with context on how much water is used relative to what is allocated and what is available. The context can help alleviate concerns (e.g. too much water use) by showing that the situation is being regulated adequately (i.e., there is enough water available compared to the amounts allocated and used). The water use report has also allowed the AER to address media enquiries and to provide factual information to both the AER and Government of Alberta to counter incorrect information in media reports. It has been recognized that the water use performance report and other industry performance reports could also be used by organizations that look at Environmental, Social and Governance metrics.

Fluid Tailing Management

In 2019-20, the AER released the 2018 State of Fluid Tailing Management for Minable Oil Sands report on its website at www.aer.ca. This report was the first year of full reporting from operators, required under Directive 085: Fluid Tailings Management for Oil Sands Mining Projects. The State of Fluid Tailings Management for Mineable Oil Sands report provides Albertans with information on regional and individual operator fluid tailings volumes relative to fluid tailings profiles and other information related to fluid tailings management for oil sands mining operations in a transparent and accessible way for the public, stakeholders and industry. The report allowed the AER to address media enquiries and to provide factual information to both the AER and Government of Alberta to counter incorrect information in media reports.

Dam Safety

In 2020, the AER published the 2019 Dam Safety Report on its website at www.aer.ca. The AER regulates 202 energy-sector dams that form 132 active ponds under Part 6 of the Water (Ministerial) Regulation and the Alberta Dam and Canal Safety Directive. In 2019, the AER completed 63 field inspections of the 132 ponds which included all extreme and high consequence ponds and all ponds containing tailings. The AER also completed 152 technical reviews of dam safety submissions. The AER's Dam Safety Program ensures that dam owners are managing their dams in accordance with the regulatory requirements, government policies, and industry best practices. The program also confirms that dam owners and our emergency response teams are prepared to respond in the unlikely event of an emergency to prevent harm to the public or the environment.

The AER also issued Manual 19 (Decommissioning, Closure, and Abandonment of Dams at Energy Projects) in January 2020. The manual provided clarification and processes for preparing and implementing decommissioning, closure, and abandonment plans under the Dam and Canal Safety Directive that was issued by Alberta Environment and Parks in December 2018. The manual is a successful outcome of engagement with mining sector dam owners and can be accessed at www.aer.ca.

Pipeline Safety: Performance Indicator 2.d

The mandate of the AER is to ensure the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources over their entire life cycle. AER-regulated pipelines transport most of the natural gas, crude bitumen and crude oil produced in Alberta to processing facilities and eventually to market. The AER uses pipeline incidents as an indicator because of the impacts incidents can have to the environment, wildlife and the public.

The AER believes that pipeline incidents are preventable. The AER takes steps to prevent pipeline failures by requiring companies to implement comprehensive integrity management programs to identify, manage, monitor and address potential hazards associated with each individual pipeline. The AER reviews pipeline incidents, and conducts pipeline inspections to ensure operators are in compliance with pipeline regulations and have proper leak detection strategies in place. AER inspections focus on identifying high risk activities such as preventative pipeline maintenance programs, pipelines that cross water courses and inactive pipelines to prevent pipeline incidents from occurring. Where appropriate, the AER also helps educate licensees on pipeline integrity issues and how to address them. If the AER identifies that a pipeline operation is at risk of causing unacceptable impacts, it can order an immediate suspension of the pipeline until the problems are corrected.

	2015	2016	2017	2018	2019
Number of high-consequence pipeline incidents	32	29	26	24	20

Source: Alberta Energy Regulator[i]

Compared with 2018, 2019 saw a decrease of high consequence pipeline incidents from 24 to 20 and a decrease in overall pipeline incidents from 416 to 390. Some factors that influenced these results in 2019 include the following:

- AER has been putting more focus on leak detection and educating industry on integrity management programs;
- There was a slight increase in the number of pipeline failures resulting from earth movement of unstable slopes. This was largely attributed to the high volume of precipitation during spring and summer. Previous years averaged three incidents, 2019 had 8 incidents. To address this issue and bring awareness to industry, AER published a Bulletin in November 2019 on the AER website at www.aer.ca; and
- Incident decreases can also be attributed to lower activity in the oil and gas sector.

Alberta Geological Survey

The Alberta Geological Survey (AGS) conducts province-wide surface and subsurface mapping, and generates fully integrated models and geoscience information to support public safety, environmental sustainability, the regulatory process, and economic prosperity.

AGS developed large-scale integrated decision-making tools and processes that allow a systems approach to decisions rather than a one-off or limited scale evaluation/decision approach. For example, the Alderson-Medicine Hat commingled field closure study examined the risk of allowing non-segregated abandonment of several thousand wells within a field to be evaluated. AGS 3-D models enable regulators to visualize and understand the impact of multiple factors within a given area, enabling faster, better-informed decision making. The study facilitated a risk-informed decision allowing field-scale, multi-well commingled abandonment, rather than segregating individual zones within individual wellbores, thereby saving significant per-well abandonment cost. AGS developed a methodology and evaluated risk for various closure scenarios in large southern Alberta gas fields that saved industry millions of dollars while considering environmental risk.

Public geoscience has been shown to have great value for stakeholders, enabling and informing scientifically-sound decision making to support environmental and regulatory issues, and public safety. Stakeholders are looking for modern, easily accessible data and data application models and tools to support their needs. AER and AGS data holdings can be leveraged by the province in integrated decision making. Public

i Reviews of past incidents and more accurate information coming available over time has resulted in changes to previously reported numbers and are subject to change as more information is gathered. For more information, see the Performance Measure and Indicator Methodology section on page 85.

geoscience is also usually the first indicator of economic opportunity, identifying potential energy and mineral opportunities that in turn, entice industry to consider development.

Indigenous Engagement at AER

The AER strives to achieve a future-state where its relationship with Indigenous peoples is one of mutual respect and trust. The organization has commenced an assessment to determine where and how the work of the AER interacts with Indigenous peoples across the regulatory life cycle, and the foundations of knowledge the organization must develop in order to be well-positioned to be proactive in this regard. This assessment includes both an exploration of tactics for the following:

- creating operational efficiencies with regulatory applications, increasing knowledge and awareness of Indigenous peoples through field operations activities; and
- determining how best to align AER's work with that of Government Alberta ministries which hold working relationships and fiduciary obligations with Indigenous communities.

In the past year, the AER made progress by improving working relationships with the Aboriginal Consultation Office through applied Indigenous awareness training and delivering joint learning initiatives with Indigenous communities.

A stronger working relationship and knowledge exchange between Indigenous elders, technicians and the AER was established through a pilot project on joint compliance inspections with First Nations and Métis Settlements. This pilot provides the opportunity for reclamation assessors to invite an Indigenous technician from the community into the field to observe how the AER completes its assessments.

The Indigenous Knowledge, Remediation, Reclamation and the AER report was released in May 2019. This report was a joint learning project with Woodland Cree First Nation that explored how Indigenous knowledge can inform the AER's delivery of its mandate with respect to reclamation and remediation. The project was timely as it raised awareness of the end of life obligations and Indigenous interests in pipeline monitoring across jurisdictions. The report can be accessed at www.aer.ca.

Concerns expressed by industry and Indigenous communities regarding efficiencies between the AER, the Aboriginal Consultation Office (ACO), and Culture, Multiculturalism and the Status of Women (CMSW) were addressed by a Directors Committee and a Core Executive Group. These groups were established to guide implementation of 18 efficiency opportunities collaboratively identified through a case study approach, premised on an example of an industry application working through the multiple regulatory processes and decisions of respective ministries and the AER. The recommendations ranged from administrative adjustments, such as establishing a centralized in-box to support communication flow between the two organizations, to process enhancements regarding the Joint Operating Procedures to account for AER approval conditions reflecting mitigation measures recommended by the ACO.

Emissions Management Training

During 2019-20, Alberta developed new requirements to reduce methane emissions in a manner that is cost-effective and recognized the unique circumstances of Alberta's oil and gas industry. Three e-learning modules were developed and provided externally to industry on these new requirements. In addition, AER facilitated four education sessions for small and medium producers in Calgary and Grande Prairie that supported industries understanding of the new requirements. These sessions reached over 100 companies that will be impacted by the regulations and the majority of attendees who responded to the survey reported better understanding of the requirements after these sessions.

Key Objective 2.4

Enhance regulation and oversight of Alberta's utilities, through the Alberta Utilities Commission (AUC), to ensure social, economic and environmental interests of Alberta are protected.

The AUC released its 2019-2022 strategic plan in November 2019, with a central theme of efficiency and limiting regulatory burden. The plan followed an actively transparent and collaborative approach that included consultation with residential and industrial consumer representatives, regulated utility corporate leaders, industry associations and other agencies to ensure alignment of the AUC's strategic plan with their concerns and challenges.

The cost of the AUC's activities in 2019-20 was $31.3 million and was fully funded by consumers through levies paid by regulated industry.

Regulatory Efficiency at the Alberta Utilities Commission

In 2019-20, the AUC released a four-pronged approach to efficiency and regulatory burden reduction through fast-tracking internal initiatives, stakeholder roundtables, an internal regulatory burden task force (comprised of the AUC's two vice-chairs and its general counsel), and an annual AUC report card, which provides detailed analysis of, and information, on the AUC's performance, including performance measure results.

The AUC led a roundtable that focused on three areas: defining regulatory burden, solutions, and next steps to prioritize solutions in order to increase its efforts on regulatory burden reduction. An extensive consultation process with stakeholders sought written input on initiatives to reduce burden, which followed an in-person, face-to-face stakeholder session on October 4, 2019.

The AUC immediately implemented greater use of technical meetings and pre-hearing meetings to define scope and issues, clarify content, determine relevancy, schedule process steps and deal with interlocutory matters in an expedited manner for select major rates and facilities proceedings. The AUC also announced, coordinated, and held a roundtable meeting in January 2020 with Alberta Environment and Parks, the Department of Energy and renewable developers represented by the Canadian Wind Energy Association and Canadian Solar Industries Association to address regulatory overlap and add flexibility to application process. The overlap in regulation arose after an Environment and Parks review of environmental plans for renewable projects and an issuance of referral reports considered as part of the application process. Steps to address this overlap are well underway.

In January 2020, the AUC used input from stakeholders on defining and measuring regulatory burden collected at three roundtables held in October and November 2019 to broaden efforts around promoting efficiency and reducing regulatory burden. Stakeholders agreed burden or regulatory impact should be measured in order to properly assess and measure the success of further AUC burden reduction. This will allow the AUC to quantify the impacts of its regulatory actions on the companies it regulates, as well as the corresponding benefits to consumers, other industry players, society, and the environment. The AUC's extensive burden reduction efforts in 2019-20 can be further explored by viewing AUC bulletins 2019-18 (October 18, 2019), 2020-02 (January 17, 2020) and 2020-11 (March, 30, 2020), available at the AUC's website at www.auc.ab.ca.

Many process efficiencies were discovered or explored, which include reducing and "right-sizing" burden and requirements to make regulatory requirements less onerous, more easily understood and more readily satisfied at a lower cost for both the regulated and the regulator. These efficiencies encourage investment and job creation by simplifying and clarifying regulatory requirements where needed, and by removing requirements where they are not necessary.

Distribution System Inquiry

Throughout 2019-20, the AUC moved forward with its Distribution System Inquiry, which was established in late 2018. The inquiry is a fundamental deep dive into the evolving nature of electric generation, consumption, storage and the significant implications for the grid, incumbent utilities, consumers, grid managers and the regulatory framework. Emerging trends in industry and among consumers raise profound questions about traditional planning approaches, rate structures, cost-recovery mechanisms, incentives and the evaluation of prudent utility costs.

Following a September 2019 technical conference the AUC completed the first module of the inquiry, focused on how emerging trends in technology and innovation are affecting distribution systems. To meet its key objective of making its proceedings more efficient, productive and timely, the AUC chose to combine the second and third modules, which focus on changes to the current business models of, and the regulatory frameworks governing, the monopoly distribution utilities, as well as examining current rate structures. This combined module started in November 2019, will finish in the mid-summer 2020, and the inquiry report will be released in early fall 2020.

Procedure and Process Modernization

Throughout 2019-20, the AUC developed and implemented refinements and modernization of its procedures and processes to improve effectiveness, efficiency and clarity of regulation, and to improve transparency and relevancy.

The AUC amended the evaluation process for specified penalties for self-reported customer care and billing contraventions. Specified penalties are comparable to pre-set fines, like parking tickets, for defined infractions by service providers of AUC rules on billing and customer care. The approach provides predictability and efficiency by doing away with the necessity of detailed proceedings and process. The changes were made following stakeholder feedback to incentivize self-reporting by changing penalty trigger thresholds and refining how cumulative infractions are considered, and how consequent penalties are accelerated with self-reported infractions to provide additional certainty and clarity to industry.

On April 26, 2019, through Bulletin 2019-05, the AUC released an updated Rule 012: Noise Control following effective and beneficial engagement with stakeholders to modernize the rule. The rule sets out how noise related to proposed utility infrastructure developments must be measured and the limits of permissible noise levels, including cumulative levels. The update provided expanded examples of testing circumstances including previously unforeseen circumstances, filled information gaps, and simplified the requirements around noise surveys.

The AUC launched an online consultation tool, AUC Engage. This online tool was developed to improve consultation, clarity, timelines, access to documents and discussions, efficiency, collaboration, scheduling, timeliness, communications, consistency, flexibility and participation for stakeholders. The tool also reduces AUC costs related to consultation, while facilitating efficient, focused processes online.

The AUC also made improvements to online access to its oral hearings, first with an ability to view exhibits, and then livestream video. The latter shows the hearing room presenters in real time. This service enhances user experience, making it easier to follow the hearing discussion for those unable to attend hearings in person. Archived hearing webcasts will continue to be available for up to 30 days after the hearing. This can also cut costs for participants, and ultimately the cost of regulation.

In June 2019, the AUC set standardized post-approval monitoring requirements for wind and solar power plants through AUC Rule 033. This change provided clarity, consistency and certainty to wind and solar power project applicants by ensuring that approved wind and solar power plant owners and operators implement effective, consistent operational mitigation measures to minimize the potential for negative effects on Alberta's wildlife and wildlife habitat. The rule improved the consistency of monitoring obligations for owners and operators of approved wind and solar power plants, adding certainty to the regulatory process. The AUC worked closely with Environment and Parks to develop the requirements. In July 2019, the AUC also set interim information requirements for solar and wind energy power plant applications to update and streamline requirements, make the process more efficient and address emerging regulatory issues.

In July 2019, the AUC announced a power plant applicant's workshop - in conjunction with Alberta Environment and Parks and the Alberta Electric System Operator (AESO) - to provide practical advice to applicants, reduce information requests and shorten application review timelines. The AUC hosted and led two workshops September 17, 2019 with more than 45 participants in attendance, including those attending remotely. Attendee responses gathered by survey were highly positive, indicating an improved understanding of each of the AUC's, AESO's and Environment and Park's requirements, and that attendees overwhelmingly received clear, direct and useful responses to their questions.

One follow-up from the workshops is an increase in pre-application meetings with prospective power plant proponents. This increase helped pushed the AUC Facilities Division's consultations with outside parties to 63 in 2019-20, up from 23 a year earlier. The increase also reflected consultations related to a review of AUC Rule 007, on the AUC's application requirements, and on the AUC's Indigenous consultation requirements.

The AUC updated the micro-generation submission guideline and forms to modernize information and graphics, and add flexibility to requirements to ease use in July 2019. The guideline reflects updated safety, electric and procedural information.

In August 2019, the AUC launched tracking of directions from AUC rates decisions to ensure visibility and transparency, and to avoid duplication.

In September 2019, the AUC clarified the rate treatment of amounts paid by a distribution utility to acquire distribution systems owned by rural electrification associations, gas co-operatives and municipalities under performance-based regulation. This resolved long-standing uncertainty that prompted a number of acquisitions to proceed.

In September 2019, through Bulletin 2019-16 and to directly support the Department of Energy, the AUC launched a broad industry consultation on emerging electricity self-supply and export issues and potential regulatory solutions to address self-supply and export issues.

In November 2019, the AUC announced a major enhancement of its electronic eFiling System platform to support efficient and secure exchange of confidential documents. The AUC eFiling System is the organization's online central record-keeping facility for all filings and all evidence used in all the AUC's proceedings, as well as administering the AUC proceeding teams, process flow, document and version control, regulatory decision making and proceeding disposition issuance. It supports the ability of the AUC and all parties before it to work completely with electronic documents from beginning to end. The enhancement, which was implemented and launched on February 8, 2020, incorporated numerous innovative features, including many suggested by stakeholders, and vastly streamlined the use and administration of confidential filings.

The improvements replaced many previously manual and laborious requirements, and included the ability to electronically submit confidential application or file documents that remain on the confidential record, stored in a secured, confidential area of the eFiling System, and for parties to designate a confidential administrator responsible for determining which individuals or representatives should have access to that party's confidential documents for each confidential proceeding. It also allows the AUC to issue public confidentiality rulings on one or more motions for confidentiality that specifies what information is to remain confidential, and identify any parties to be excluded from submitting a confidentiality undertaking, proceeding participants to submit a confidentiality undertaking for each individual requiring access to the confidential record with notification to the disclosing party's confidential administrator to grant or deny access to the confidential record for the individual, and users to search for confidential documents for approved users.

Alberta Utilities Commission COVID-19 Response Initiatives

With the arrival of the COVID-19 pandemic in Alberta, beginning in mid-March 2020, the AUC took a series of decisive steps to, first, mitigate the risk to its personnel, operations and participants that appear before it; second, to support Alberta utilities to continue to deliver critical safe and reliable utilities service; and, third, to adopt, under the circumstances, a more suitably flexible approach to regulation. The AUC deferred live proceedings, consultations and information sessions, began working remotely while ensuring its teams remained fully engaged on regulatory files, and then launched a series of measures to support consumers and utility providers, including:

- Leading a consultation to coordinate utility customer COVID-19 relief efforts so that all customers could be assured of equal treatment;
- Supporting and facilitating the Alberta government's Utility Payment Deferral Program (see below);
- Suspending specified penalties for self-declared contraventions to allow electric and natural gas utilities, service providers and retailers to focus their resources on helping customers;
- Deferring quarterly distribution utility and energy service provider service quality and reliability performance filings;
- Supporting the Market Surveillance Administrator in adopting a flexible approach to reliability standards for market participants;
- Issuing interim COVID-19 changes to the AUC participant involvement program to mitigate risk to stakeholders and provide applicants more time and flexibility around consultations;
- Initiating tracking and reporting the impact of the COVID-19 pandemic on utility operations, costs and revenues; and
- Suspending certain requirements for costs claim applications and confidentiality undertakings.

Utility Payment Deferral Program

In March 2020, the Government of Alberta announced that residential, farm and small commercial utility ratepayers could defer utility payments until June 18 – a period of 90 days - and that utility services would not be cut off or reduced during this period for non-payment, to ensure that Albertans in financial hardship as a result the COVID-19 pandemic were protected from having their services cut off or reduced during this period.

Consumers eligible for the deferral program included anyone who was experiencing financial hardship and could not make regular payments as a result of COVID-19 pandemic. This deferral applied to bills for residential, farm and small commercial service:

- electricity consumers, who consume less than 250,000 kilowatt hours of electricity per year, and
- natural gas consumers, who consume less than 2,500 gigajoules per year.

The government and the AUC worked with utility companies to develop an approach for repayment that allows consumers to pay back their deferred utilities within a reasonable time period.

Key Objective 2.5

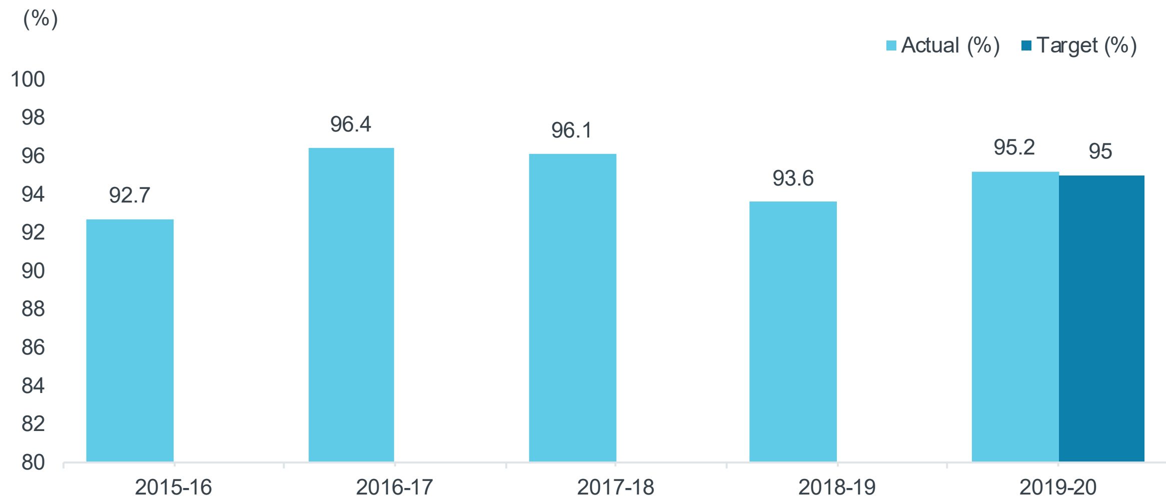
Audit the financial losses of the power purchase agreements held through the Balancing Pool.

The planned audit was suspended pending the conclusion of AUC proceeding regarding negotiated settlement agreement between the Market Surveillance Administrator and the Balancing Pool. On January 14, 2020, the AUC approved the settlement agreement. The Government of Alberta is working with the Balancing Pool on the appropriate timing to initiate the audit.

Performance Measure 2.a: Timeliness of application processing (Alberta Energy Regulator)

Target: The overall turn around target for 2019-20 is 95 per cent of applications meeting their respective turnaround targets.

Percentage of Alberta Energy Regulator applications that met turnaround targets



Source: Alberta Energy Regulator[i]

Discussion of Results

The measure indicates the Alberta Energy Regulator's efficiency in meeting application process timelines. Every application process receives a turnaround target at the time of application receipt respective of the complexity that process represents. This measure monitors the overall efficiency of the AER's application processing, drives internal performance, and provides certainty and transparency to the public related to AER's turnaround targets.

In 2019-20, 95.2 per cent of AER applications met turnaround targets. This result was 0.2 per cent higher than the 2019-20 performance target of 95 per cent, and a 1.6 per cent increase from the 2018-19 result. Further performance improvements are anticipated in the future as the organization continues to shift towards a focus on risk-informed decision making, with further reductions in turnaround targets expected. The AER processes thousands of applications each year. Applications can vary in complexity; some are simple, while others may require considerable review internally and by third parties. Volume and complexity prevent the AER from being able to set a target of 100 per cent across all application types.

In 2020-21 and beyond, AER will report results for this measure for both routine and non-routine applications.

Application turn around targets for each application process can be found on the AER's website: www.aer.ca

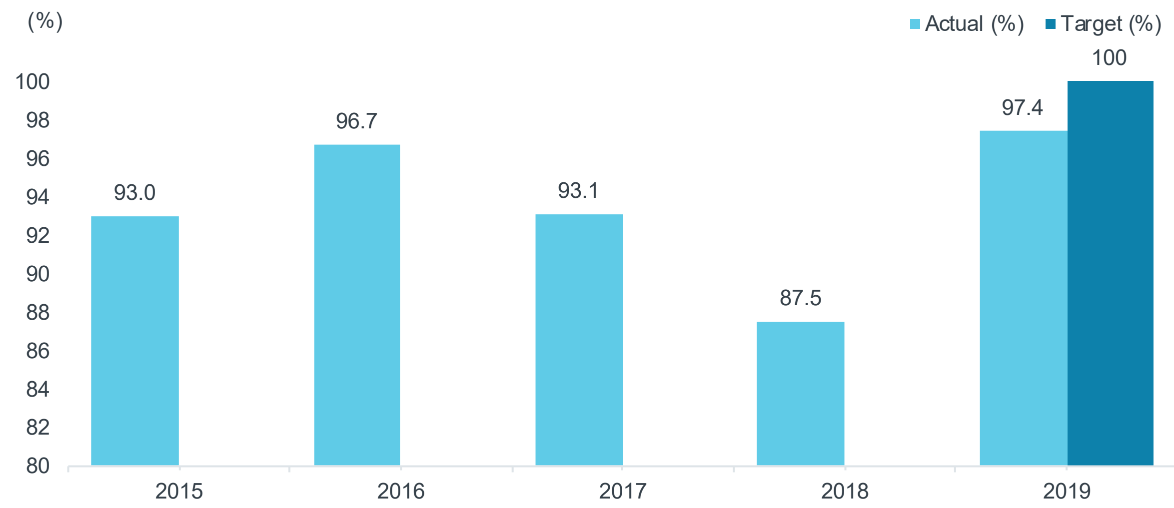
For more information and analysis of how the AER is working to reduce application turnaround times, see reporting on the Integrated Decision Approach and Regulatory Efficiency Initiative under Key Objective 2.4 of this report.

i For more information, see the Performance Measure and Indicator Methodology section on pages 83.

Performance Measure 2.b: Timeliness of the needs and facility applications (Alberta Utilities Commission)

Target: 100 per cent

Percentage of Alberta Utilities Commission needs and facilities applications determined within 180 days



Source: Alberta Utilities Commission[i]

Discussion of Results

In accordance with standards established in Alberta law, the AUC, when considering an application for an approval, permit or licence in respect of a needs identification document, transmission line or part of a transmission line, must make a decision in a timely manner, and if possible, within 180 days after receipt of a complete application. For 2020, the AUC met this standard 97.4 per cent of the time as 37 of 38 decisions were issued within the 180-day timeline. The decision that missed the 180-day deadline addressed novel, complex issues and was placed in abeyance at the request of one of the applicants to do additional technical consultation.

The applications related to the delayed decision were regarding a new transmission development within the City of Edmonton and were contested by sophisticated interveners. This was a joint Need Identification Document (NID) and facility application. The NID application was complex as it addressed novel issues relating to distribution reliability criteria. The facility application was also contentious because the transmission addition proposed was partially routed through a residential neighbourhood.

Facility Application Streamlining

Throughout 2019-20, the AUC moved to streamline application processes and processing for utility facility applications to construct and operate utility infrastructure for both electricity transmission power plants (wind, solar, natural gas-fired), and consumer natural gas transmission. Further, the AUC tightened its internal (and externally transparent) timelines on electricity transmission processing timelines. These efforts included full stakeholder involvement and consultation. These efforts fall into two general categories, reflected in three separate announcements:

[i] For more information, see the Performance Measure and Indicator Methodology section on page 84.

- On June 19, 2019, the AUC released Bulletin 2019-08, which streamlined the application process for gas utility pipeline applications by reducing steps, adopting direct self-reporting by operators to the provincial database, and eliminating decision reports for minor pipeline amendment applications. These steps to improve AUC and gas pipeline operator efficiency and reduce regulatory burden.
- On June 27, 2019, through Bulletin 2019-10, the AUC launched an in-depth review of AUC Rule 007, which sets out requirements for electric facilities applications. The review sought to generally update and streamline existing requirements to make the application process more efficient for applicants, interveners and the AUC. Within that it sought to provide applicant clarity and fairness, and improve regulatory efficiency around indigenous consultation, end-of-life management for power plants, emergency response plans, time extensions for power plants, the required notification and participant involvement program, solar glint and glare assessment, shadow flicker, the buildable area concept for wind development, and battery storage.
- On September 9, 2019, through Bulletin 2019-15, the AUC announced the implementation of new performance standards and timelines for processing facilities applications retroactive to August 1. Category criteria were refined and new performance standards were added to provide greater transparency and accountability for facility application processing.

Along with extensive opportunities to refine approaches, enhance efficiency, and clarify requirements, the work behind these improvements also provided an opportunity to better understand applicants' businesses, interests, and concerns. Each provided a platform to build effective relationships between regulators and stakeholders of all kinds. Among the benefits was understanding the possibility for other improvements that could be made, and additional stakeholder concerns or preferences that could be addressed. In some areas, these initiatives allowed the AUC to stay ahead of technological evolution and industry change. Developing a better understanding of solar glint and glare, shadow flicker and battery storage are all examples of this. Being able to accommodate industry evolution efficiently is an important part of ensuring social, economic and environmental interests of Alberta are protected.

Specific improvements were also made for natural gas and electric facilities applicants:

- For electric facilities applicants (the bulk of facilities applications received by the AUC), application requirements are being streamlined, and approaches are being developed to deal with emerging issues in understanding the potential social, economic and environmental impact of proposed projects.
- For natural gas facilities applicants, steps and work was eliminated: for the AUC, technical pipeline database registration work was eliminated, and dispositions were reduced. This will facilitate investment and maintenance in consumer natural gas pipelines by making the regulatory and permitting process more easily understood and implemented, simpler and less burdensome.

Appendix A: Energy Highlights Table

Resource		2019-20	2018-19
Bitumen	Revenue	$4.09 billion	$3.21 billion
	Bitumen wells drilled [1]	1,069 (2019)	1,515 (2018)
	Total bitumen production in barrels per day (bbl/d)	3.10 million bbl/d (2019)	3.05 million bbl/d (2018)
	Marketable bitumen and Synthetic Crude Oil (SCO) production [2]	2.93 million bbl/d (2019)	2.88 million bbl/d (2018)
Conventional Crude Oil	Revenue	$1.17 billion	$1.15 billion
	Average price for West Texas Intermediate (WTI)	US$54.84/bbl	US$62.73/bbl
	Conventional crude oil production	0.49 million bbl/d (2019)	0.49 million bbl/d (2018)
	Pentanes and condensate production	0.34 million bbl/d (2019)	0.32 million bbl/d (2018)
	Crude oil wells drilled[1]	1,755 (2019)	2,194 (2018)
Total Crude and Equivalent	Production (conventional, marketable bitumen and SCO, pentanes plus and condensates) [2]	3.75 million bbl/d (2019)	3.69 million bbl/d (2018)
	Removals from Alberta [2]	3.64 million bbl/d (2019)	3.56 million bbl/d (2018)
	Percentage of total crude oil and equivalent disposition [2]	87% (2019)	87% (2018)
Natural Gas and By-Products	Revenue	$0.37 billion	$0.54 billion
	Average Alberta Natural Gas Reference Price (ARP)	$1.39/GJ	$1.34/GJ
	Number of conventional natural gas wells drilled[1]	687 (2019)	937 (2018)
	Total marketable natural gas production including Coalbed Methane	3.6 Tcf (2019)	3.8 Tcf (2018)
	Coalbed Methane production	0.16 Tcf (2019)	0.20 Tcf (2018)
	Total natural gas disposition	4.27 Tcf (2019)	4.53 Tcf (2018)
	* To the United States	32%	35%
	* Within Alberta	46%	43%
	* To rest of Canada [2]	22%	23%
Bonuses and Sales of Crown Leases	Revenue from bonuses and sales of Crown leases	$0.12 billion	$0.36 billion
	Revenue from rentals and fees	$0.17 billion	$0.16 billion
	Average price per hectare (ha) paid at petroleum and natural gas rights sales[3]	$137.15	$271.74
	Petroleum and natural gas hectares sold at auction[3]	774,896.36 ha	1,301,265.72 ha
	Average price per hectare paid for oil sands mineral rights[3]	$111.59	$161.76
	Oil sands hectares sold at auction[3]	99,464 ha	35,862 ha
Freehold Mineral Tax	Revenue	$75 million	$67 million
Wells and Licenses	Well Licenses issued [2, 4]	5,160 (2019)	6,436 (2018)
	Industry drilling[5]	4,464 (2019)	5,513 (2018)

Resource		2019-20	2018-19
Coal	Revenue	$13 million	$10 million
	Established coal reserves (estimate)	33.2 billion tonnes	33.2 billion tonnes
	Raw coal production	24.8 million tonnes (2019)	22.2 million tonnes (2018)
	Total marketable coal deliveries	19.6 million tonnes (2019)	18.9 million tonnes (2018)
	Percentage of total coal deliveries exported out of province	30.7% (2019)	19.4% (2018)
Electricity	Total generation capacity in Megawatts (MW)	16,515 (2019)	16,193 (2018)
	Total generation capacity from renewable sources	3,028 (2019)	2,825 (2018)
	Total generation capacity from coal	5,273 (2019	5,273 (2018)
Metallic and Industrial Minerals	Metallic and Industrial minerals Royalty Revenues (MINRS)	$732,016	$714,947
	Hectares of mineral permits issued to exploration companies (LAMAS,MIM Permits and New Application Issued)	0.9 million ha	1.7 million ha
Upstream Energy Sector Direct and Indirect Employment	Direct and indirect employment [2]	436,000 (2019)	454,000 (2018)
Upstream Energy Sector Investment	Investment [2]	Estimated $24.0 billion (2019)	$28.6 billion (2018)

Notes:

1) Data on wells drilled include both development and exploratory wells.
2) Data results for 2018 have been retroactively adjusted to reflect the updates that took place since the publication of the 2018-19 Annual Report.
3) Excluded from these figures are direct sales which comprise of fractional land, complementing rights or single substance leases. These sales are initiated by the purchaser and are therefore not predictable in nature.
4) Data for conventional gas, crude oil and bitumen wells licences.
5) In addition to development and exploratory bitumen, crude oil, and natural gas wells drilled, total industry drilling includes oil sands evaluation wells, and other wells, such as water, waste, brine, and miscellaneous wells. Coalbed methane wells are also included, where applicable.

Performance Measure and Indicator Methodology

Performance Measure 1.a

Alberta's oil sands supply share of global oil consumption

Methodology

This measure is calculated as the annual ratio of the total number of barrels of Alberta oil sands production over the total number of barrels of world oil consumption:

(Annual Barrels of Alberta Oil Sands Production)/(Barrels of World Oil Consumption)

The total for annual barrels of Alberta oil sands production is the sum of total mined and in-situ bitumen production in any given calendar year. Bitumen production data is calculated from Alberta Energy Regulator's reports. Global oil consumption data is based on the Oil Market Report, published by the International Energy Agency.

Sources

Alberta Energy Regulator; International Energy Agency

Performance Indicator 1.b

Production: Alberta's crude oil and equivalent annual production; and Alberta's total marketable natural gas annual production

Methodology

Alberta's crude oil and equivalent annual production

The crude oil and equivalent annual production portion of the indicator consists of three components:

- Volume (thousands of barrels/day);
- As a percentage of Canadian production;
- Total percentage of crude oil leaving Alberta.

The indicator reports the volume of Alberta's annual crude oil and equivalent production, Alberta's share of total Canadian production, and total percentage of Alberta disposition, which is leaving Alberta.

It demonstrates the vital role that Alberta has in the Canadian oil market context. Components one and two of the indicator focus only on the production of crude oil and equivalent. Alberta's crude oil and equivalent production consists of conventional crude production, marketable oil sands production (which consists of non-upgraded bitumen and upgraded bitumen), and condensate and pentanes plus. All data for components one and two of the indicator is taken from the Canada Energy Regulator. Generally, the Ministry of Energy relies on the Alberta Energy Regulator to report Alberta oil statistics. However, as the requirement of the indicator is to compare Alberta with the rest of Canada, the CER is used as a source to avoid mixing the sources.

For the third component of this indicator, the Ministry of Energy reports the share of total volume that leaves Alberta as a percentage of total Alberta oil disposition. All data for this component is calculated from the AER's reports.

Alberta's total marketable natural gas annual production

The total marketable natural gas production portion of the indicator consists of three components:

- Volume (billion cubic feet/day);
- As a percentage of Canadian production;
- Total percentage of natural gas leaving Alberta.

The indicator reports the volume of Alberta's marketable natural gas production, Alberta's share of total Canadian production, and total percentage of Alberta disposition, which is leaving Alberta.

Components one and two of the indicator focus only on the production of marketable natural gas. The indicator has been reporting the volume of Alberta's annual gas production, as well as Alberta's share of total Canadian production. It demonstrates the vital role that Alberta has in the Canadian gas market context. For this indicator, the Ministry of Energy reports total marketable natural gas production volumes.

All data for the present indicator is taken from the CER. Generally, the ministry relies on AER to report Alberta gas statistics. However, as the requirement of the present indicator is to compare Alberta with the rest of Canada, the CER is used as a source to avoid mixing the sources.

For the third component of this indicator, the Ministry of Energy reports the share of total volume that leaves Alberta as a percentage of total Alberta gas disposition. All data is calculated from the AER's reports.

Note: previously, in the 2018-21 Business Plan, the disposition components of the present "Production" indicator were reported as the "Market Access" indicator. The "Market Access" indicator in the 2018-21 Business Plan reported both "Total percentage of crude oil leaving Alberta" and "Total percentage of natural gas leaving Alberta". "Market Access" components were included in the "Production" indicator in the 2019-23 Business Plan. There have been no methodological changes to how the disposition shares are calculated from the AER reports as a result of this reporting adjustment.

Performance Indicator 1.c

Investment: Upstream and Downstream

Methodology

Upstream: Mining, Quarrying, and Oil and Gas industry investment in Alberta

The upstream portion of the indicator consists of the following components:

- Cdn$ Billions
- Alberta as a Percentage of Canadian investment

This portion of the indicator reports investment in Alberta's Mining, Quarrying, and Oil and Gas Extraction sector. It also puts Alberta in the national context, by reporting Alberta's mining, quarrying, and oil and gas investment as a percentage of total Canadian investment in the sector.

The data for the indicator are taken from Statistics Canada. Data are reported on a calendar year basis.

Downstream: Petroleum, Coal and Chemical Manufacturing

The downstream portion of the indicator consists of the following components:

- Cdn$ Billions
- Alberta as a percentage of Canadian investment

In addition to upstream investment, the energy industry generates significant downstream activity; this portion of the indicator focuses on the investment impacts of the downstream activity. The indicator is explicitly focused on petroleum and coal product manufacturing, and chemical manufacturing; this allows for the coverage of petroleum refining and petrochemical manufacturing activity, among other downstream activities.

The "Downstream: Petroleum, Coal and Chemical Manufacturing" portion of the indicator can be treated as complementary to the "Upstream: Mining, Quarrying, and Oil and Gas industry investment in Alberta" portion of the indicator. There is no overlap between the data reported by both portions of the indicator, as they are based on different industrial categories.

Just like investment data in the "Upstream: Mining, Quarrying, and Oil and Gas industry investment in Alberta", data for the "Downstream" portion of the indicator are taken from Statistics Canada. Data are reported on a calendar year basis.

In addition to actual results, both the "Upstream" and "Downstream" components of the present indicator also report the most current preliminary actual results, to enhance the timeliness of data presentation. The preliminary actual results will in all likeliness be revised once the actual results become available.

Performance Measure 2.a

Timeliness of application processing (Alberta Energy Regulator)

Methodology

Data used to populate this measure come from four data sources:

- Integrated Application Registry (IAR) – IAR is the application workflow engine used for most of the applications that were regulated by the Energy Resources Conservation Board (ERCB) (*Oil and Gas Conservation Act*, *Oil Sands Conservation Act*, Coal Conservation Act, *Pipeline Act*).
- PLA AppTracker – The PLA AppTracker is a Microsoft Access solution used to track applications submitted under the *Public Lands Act*.
- AppTracker – The AppTracker is a Microsoft Access solution used to track applications submitted under the *Environmental Protection and Enhancement Act*, the *Water Act*, and applications processed by the former ERCB that are not captured in IAR.
- OneStop – OneStop is the new application workflow engine being developed and implemented to eventually encompass all AER applications. Pipeline applications, water act approvals, land use applications, new well applications, and reclamation certificates are processed through OneStop. Well amendment applications are scheduled to be processed in OneStop in the third quarter 2020-21 fiscal year. All data from OneStop with the exception of reclamation certificates has been incorporated into this metric. It is expected that reclamation certificate data will be added in the 2020-21 fiscal year.

Source

Alberta Energy Regulator

Performance Measure 2.b

Timeliness of the needs and facility applications (Alberta Utilities Commission)

Methodology

The statutory deadline for issuing decision reports is 180 days, with possible 90-day extensions under certain circumstances. These statutory timelines begin on the date when the Alberta Utilities Commission (AUC) deems the application complete. The status of applications is tracked daily.

Source

Alberta Utilities Commission

Performance Indicator 2.c

Regulatory enforcement (Alberta Energy Regulator)

Methodology

The data source is the Field Surveillance Inspection (FIS) system. A .SQL script pulls the results for this indicator; the data is deemed to be reliable and credible as a result of data integrity procedures and required manual review of inspection records.

AER field inspectors inspect the activities of the in-situ and conventional oil and gas, pipeline, and coal and oil sands mining industries. The inspection findings and outcome are recorded in the FIS system database. Geophysical inspections are not included in the FIS system due to legislated confidentiality requirements, and therefore are not included in these results.

The field inspections for this indicator include the following activities: drilling operations, gas facilities, oil facilities, pipelines, well servicing operations, drilling waste, well sites, coal mines, mineable oil sands and waste management facilities. The inspection count is based on initial inspections and re-inspections.

Initial inspections are selected based on an enterprise management approach to defining and applying risk as well as the predetermined level of risk that an activity may pose to health and safety, the environment, resource conservation, and stakeholder confidence in the regulatory process, including public and political influences. Historical operator compliance is a component of the risk-based site selection process. Re-inspection may be needed subsequent to the initial inspection and is at the discretion of the inspector.

The list of enforcement action types for all years has been updated to include warning letters, orders, section 106 and prosecutions. Previously, non-compliances with suspensions and administrative sanctions were included, however they have now been removed as they can occur without an investigation, therefore they are not truly a type of field enforcement action.

2019-20 data were retrieved on April 21st, 2020. The reported numbers include closed, amended and reconsidered enforcement decisions. Add note on methodology change once clarified with AER.

Source

Alberta Energy Regulator

Performance Indicator 2.d

Pipeline safety (Alberta Energy Regulator)

Methodology

A reportable pipeline incident under the Alberta Energy Regulator's jurisdiction is any pipeline release, break or contact damage (regardless if there is a release) (Section 35 of the *Pipeline Act*). Incident information is entered into the AER's Field Inspection System (FIS) database by AER inspectors. The incident information is used to assign a consequence rating by the AER to indicate the severity of the incident. High consequence pipeline incidents are those that could have significant impacts to the public, wildlife, or the environment, or that involve the release of a substance that affects a large area or water body. Records are reviewed for accuracy and consistency.

Source

Alberta Energy Regulator

Performance Indicator 2.e

Annual Wells Decommissioned (Alberta Energy Regulator)

Methodology

An Inactive Well List count is published daily on the AER website. To facilitate year over year comparisons, historical data is captured annually as of December 31 of each year. The following formula is used:

Per cent of wells decommissioned and left in a safe and secure condition = Annual Wells Decommissioned divided by (Inactive Well Inventory +Annual Wells Decommissioned)

Inactive Well Status is based on data retrieved from Petrinex. Wells are deemed inactive as per Directive 013 as follows:

- Critical sour wells (perforated or not) that have not reported any type of volumetric activity (production, injection or disposal) for six consecutive months;
- All other wells that have not reported volumetric activity (production, injection or disposal) for 12 consecutive months.

Well Decommissioning is based on surface abandonments for a well. A well may be decommissioned multiple times over its life (e.g., abandoned, re-entered and then abandoned again). A query is used to retrieve only the most recent record for a given surface abandonment date. Note that if a well has multiple abandonment records in multiple years, these are counted within each year.

Data is submitted by industry operators. Specifically, production data submitted to Petrinex and well licence abandonments submitted via the Digital Data Submission. The reliability of the data is contingent on industry operators providing the AER with up-to-date information.

Source

Alberta Energy Regulator

Financial Information

For the year ended March 31, 2020

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Reporting Entity and Method Consolidation

The financial information is prepared in accordance with government's stated accounting policies, which are based on Canadian Public Sector Accounting Standards.

The reporting entity is the ministry for which the Minister of Energy is accountable. The accounts of the Ministry, which includes the Department of Energy, the Alberta Energy Regulator, the Alberta Utilities Commission, the Canadian Energy Centre Ltd. and the Post-Closure Stewardship Fund, are consolidated on a line by line basis.

Under this method, accounting policies of the consolidated entities are adjusted to conform to government accounting policies and the results of each line item in their financial statements (revenue, expense, assets, and liabilities) are included in government's results. Revenue and expense, capital, investing and financing transactions and related asset and liability balances between the consolidated entities have been eliminated.

The Alberta Petroleum Marketing Commission and the Balancing Pool are government business enterprises (GBE) and are accounted for on a modified equity basis. Under the modified equity method, the accounting policies of the GBE are not adjusted to conform to those of the Ministry of Energy. Inter-entity revenue and expense transactions and related asset and liability balances are not eliminated.

A list of the individual entities making up the ministry are shown on the "Management's Responsibility for Reporting" statement included in this annual report.

Ministry Financial Highlights

Statement of Revenues and Expenses

Year ended March 31, 2020

	2020		2019	Change from	
	Budget	Actual	Actual (Restated)	Budget	2019 Actual (Restated)
		(in thousands)			
Revenues					
Non-Renewable Resource Revenue					
Bitumen Royalty	$ 4,682,000	$ 4,088,981	$ 3,213,729	$ (593,019)	$ 875,252
Crude Oil Royalty	1,163,000	1,174,553	1,149,125	11,553	25,428
Natural Gas and By-Products Royalty	362,000	371,938	535,925	9,938	(163,987)
Bonuses and Sales of Crown Leases	164,000	119,832	360,467	(44,168)	(240,635)
Rentals and Fees	147,000	169,189	159,961	22,189	9,228
Coal Royalty	9,000	12,785	9,803	3,785	2,982
Total Non-Renewable Resource Revenue	6,527,000	5,937,278	5,429,010	(589,722)	508,268
Freehold Mineral Rights Tax	67,000	75,035	66,882	8,035	8,153
Industry Levies and Licenses	320,450	330,677	329,653	10,227	1,024
Other Revenue	6,384	7,681	42,464	1,297	(34,783)
Net Income (Loss) from Government Business Enterprises					
Alberta Petroleum Marketing Commission	(172,482)	(2,677,862)	(215,109)	(2,505,380)	(2,462,753)
The Balancing Pool	210,192	161,231	360,880	(48,961)	(199,649)
Ministry total revenues	6,958,544	3,834,040	6,013,780	(3,124,504)	(2,179,740)
Inter-ministry consolidation adjustments	-	(457)	(146)	(457)	(311)
Ministry total revenues	6,958,544	3,833,583	6,013,634	(3,124,961)	(2,180,051)
Expenses - Directly Incurred					
Ministry Support Services	7,443	5,891	5,420	(1,552)	471
Resource Development and Management	95,498	82,084	62,441	(13,414)	19,643
Cost of Selling Oil	83,000	83,627	79,512	627	4,115
Climate Change	103,472	89,359	84,828	(14,113)	4,531
Carbon Capture and Storage	136,468	60,476	165,912	(75,992)	(105,436)
Market Access	1,500,000	866,098	5,850	(633,902)	860,248
Energy Regulation	236,331	264,248	259,451	27,917	4,797
Utilities Regulation	32,885	32,434	32,181	(451)	253
Orphan Well Abandonment	55,813	61,039	45,959	5,226	15,080
Ministry total expenses	2,250,910	1,545,256	741,554	(705,654)	803,702
Inter-ministry consolidation adjustments	-	(738)	(985)	(738)	247
Adjusted ministry total expenses	2,250,910	1,544,518	740,569	(706,392)	803,949
Annual Surplus before inter-ministry consolidation adjustments	4,707,634	2,288,784	5,272,226	(2,418,850)	(2,983,442)
Inter-ministry consolidation adjustments	-	281	839	281	(558)
Adjusted annual surplus	$ 4,707,634	$ 2,289,065	$ 5,273,065	$ (2,418,569)	$ (2,984,000)

Revenue and Expense Highlights

Revenues

Energy's 2019-20 total revenues of $3.83 billion consist of the following:

- **Non-Renewable Resource revenues** totalling $5.94 billion was $590 million lower than budgeted primarily due to lower Bitumen Royalties ($593 million). The decrease was primarily due to lower than forecast WTI and Western Canadian Select (WCS) prices.
- **Freehold Mineral Rights Tax** revenues totalled $75 million and relate to annual taxes on private freehold mineral rights.
- **Industry levies and licences** totalled $331 million and relate to levies and licences collected from industry by the Alberta Energy Regulator (AER) and the Alberta Utilities Commission (AUC).
- **Net Losses from Government Business Enterprises** totalling $2.52 billion was lower than budget by $2.55 billion primarily due to lower than anticipated income from the APMC of $2.51 billion due to the onerous contract provision associated with the Sturgeon Refinery Processing Agreement.

Expenses

Energy's 2019-20 operating expenditures totalled $1.55 billion, with an operating surplus of $706 million compared to budget and increased spending of $804 million compared to 2018-19. This was primarily related to:

- **Market Access** – In February 2019, under the previous government, the APMC (as an agent of the crown) initiated the Crude by Rail program to address market access constraints that have landlocked Alberta energy resources from global export and lowered the relative value of Alberta resources from an international perspective. In May 2019, the current government directed the APMC to proceed with the divestment of the program to the private sector. As part of the current government's priorities, it was determined that the Government of Alberta would cease direct involvement in this program. As a result, the ministry was approved as part of Budget 2019 to incur a $1.5 billion cost to fully divest of the program.
    - In 2019-20, the program incurred costs of $866 million which was $634 million lower than budget. This was primarily due to delays in divesting the program due to a downturn in the economy and adverse market conditions. The APMC has finalized binding agreements to transfer the obligation to the private sector. The current fiscal environment, due to COVID-19, has created additional challenges for the APMC to complete the assignment process and be fully divested. Negotiations for divestiture are ongoing.
    - The year over year increase compared to prior year was due to the timing of the set up of the program. The ministry incurred development costs of $6 million in 2018-19.
- **Carbon Capture and Storage** – This program supports two Carbon Capture and Storage projects in Alberta: the Shell Quest Project and the Alberta Carbon Trunk Line Project (ACTL). Due to construction delays, this program incurred lower than anticipated costs compared to budget of $76 million. The year over year decrease in spending of $105 million was due to the timing of payments related to milestone achievements as the ACTL project achieved a number of milestones in 2018-19.

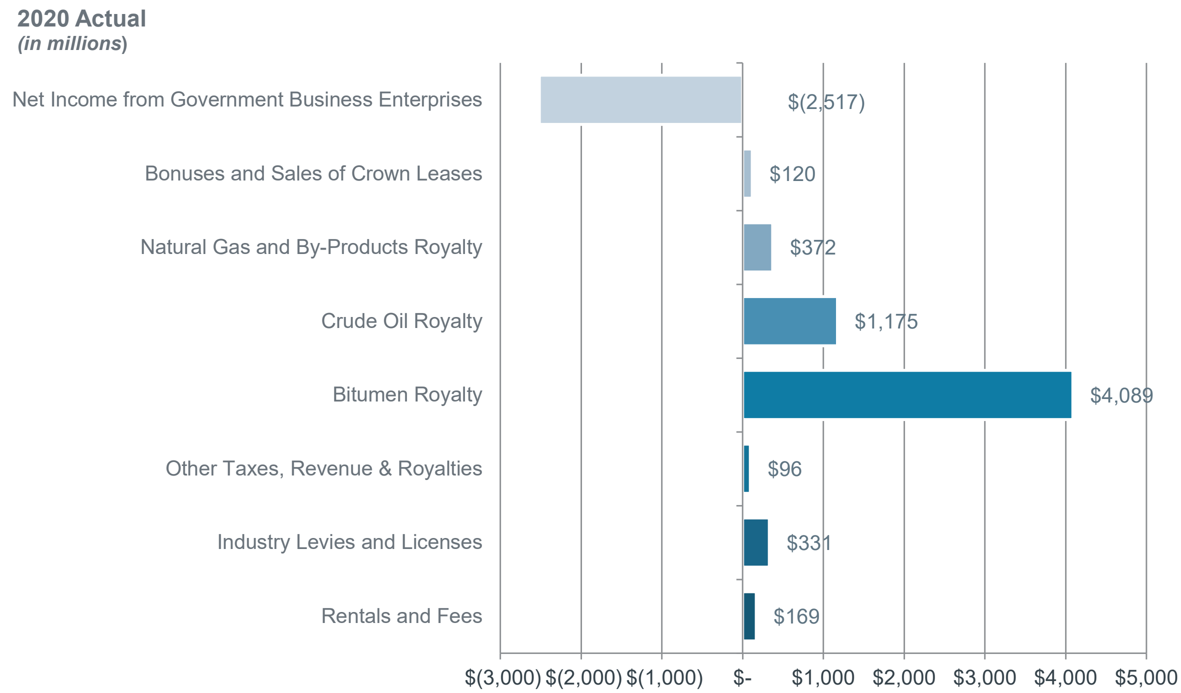
Continued...

Revenue and Expense Highlights...Continued

- **Energy Regulation** – This represents the costs incurred by the Alberta Energy Regulator (AER) to support the regulation of Alberta's energy resources. The AER's mandate provides for the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources over their entire life cycle. This includes allocating and conserving water resources, managing public lands, and protecting the environment while providing economic benefits for all Albertans. The AER's activities are fully funded by industry levies.
  - In 2019-20, the AER underwent an organizational restructuring as part of the current government's mandate to streamline operations and improve efficiency. As such, the AER incurred operating costs totalling $264 million, which is $28 million higher compared to the approved budget. This is primarily due to severance and additional labour costs required as a result of the timing of staff reductions which occurred later in the fiscal year than originally contemplated in Budget 2019.
- **Resource Development and Management –** Resource development and management captures the costs incurred by the ministry to support various energy policy and operations activities. The ministry develops strategic policies to support Alberta's energy and mineral resource markets and electricity systems. It also oversees Alberta's energy, mines and minerals royalty and tenure systems (which includes the calculation and collection of revenues from energy and mineral royalties, mineral rights leases, and bonuses and rent). The ministry also provides industry advocacy to ensure the spreading of misinformation about Alberta's energy industry are addressed, which includes activities associated with the Canadian Energy Centre (CEC). The CEC's mandate is to promote Canada as the supplier of choice for the world's growing demand for responsibly produced energy. This activities have an approved budget of $96 million
  - Energy Policy (Budget: $44 million) – The ministry incurred a surplus of $8 million primarily due to lower than anticipated spending on various platform items and lower than anticipated labour costs due to attrition and delays in hiring.
  - Energy Operations (Budget: $22 million) - The ministry experienced a $19 million deficit primarily due to an increase in allowances booked for doubtful accounts ($21 million) as a result of economic conditions, partially offset by lower than anticipated labour costs due to attrition and delays in hiring.
  - Industry Advocacy (Budget: $30 million) – The approved budget was primarily related to costs associated with the CEC. The ministry experienced a $24 million surplus primarily due to the timing of when the CEC was brought to full operations.

Breakdown of Revenues

The following information presents detailed revenues of the ministry. The objective of detailed revenues disclosure is to provide information that is useful in understanding and assessing the financial impact of government's revenue raising and for enhancing legislative control.



Non-Renewable Resource Revenue

Revenue ($ Millions)	2019-20 Budget	2019-20 Actual
Bitumen Royalty	$ 4,682	$ 4,089
Crude Oil Royalty	1,163	1,175
Natural Gas & By-Products	362	372
Bonus and Sales of Crown Leases	164	120
Rentals and Fees	147	169
Coal Royalty	9	13
Non-Renewable Resource Revenue	**$ 6,527**	**$ 5,937**

Source: Government of Alberta

- **Bitumen** royalties remained the largest portion of resource royalty revenue. In 2019-20, bitumen revenue totaled $4.1 billion. Actual bitumen royalties were about 13 per cent, or $593 million lower than budgeted. This variance is mainly due to lower than forecast WTI and Western Canadian Select (WCS) prices on average for the fiscal year.
- **Conventional crude oil** royalties contributed $1.17 billion. Conventional crude oil royalties were $12 million, or one per cent higher than the budgeted amount due to higher than forecast condensate royalty, lower exchange rate and lower royalty reduction program costs.

Continued...

Breakdown of Revenues...Continued

- **Natural gas and by-products royalties** brought in $372 million and were $10 million above the budgeted amount. Prices for natural gas by-products such as propane, butane and pentanes plus follow oil prices. Lower oil prices and lower gas production was offset by higher than forecast Pentanes production as companies are trying to maximize natural gas liquids extraction, especially pentanes plus as it is used as diluent for oil sands production.
- In 2019-20, **Bonuses and Sales of Crown Leases** totaled $120 million, which was $44 million or 27 per cent lower than the budgeted amount. The majority of the sales (87 per cent) were from petroleum and natural gas leases (PNG). The number of PNG hectares sold and the average price per hectare were lower than forecast.
- Revenue from **Rentals and Fees** was $169 million in 2019-20, exceeding the budgeted revenue by $22 million, or 15 per cent. Rentals and fees revenue is tied to land sales in the current and the previous years. The higher than budgeted revenue was mainly due to the sale of more oil sands hectares than forecasted and higher retention rates for leases and licences by industry. This affects rentals and fees because in addition to the bonus amounts paid for the hectares sold, an agreement issuance fee and rental for the first year of the agreement is required.
- Included in **other taxes, revenue and royalties** totalling $96 million is revenue from coal royalty, which brought in $13 million and was $4 million higher than budgeted. Also included is freehold mineral rights tax revenue, which was $75 million and was $8 million higher than budget.

Royalty Program Adjustments

The ministry has a number of royalty programs under the Alberta Royalty Framework, which no longer accept new participants as of 2017 and will be phased out once their regulation expires. These programs will be replaced by the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program. The programs to be phased out include the Natural Gas Deep Drilling Program, Emerging Resources and Technologies Initiative, Incremental Ethane Extraction Program and the Enhanced Oil Recovery Program. The ministry will continue to monitor and report on the progress of these programs until they have officially expired.

2019-20 Non-Renewable Resource Revenues are reported net of the following royalty program adjustments:

	2020	2019 Restated
	(in thousands)	
Royalty Program:		
Natural Gas Deep Drilling Program	$ 354,437	$ 676,798
Shale Gas	68,758	159,384
Horizontal Oil	9,207	44,594
Incremental Ethane Extraction Program	14,489	28,849
Enhanced Oil Recovery Program	15,985	21,252
Proprietary Waiver	2,001	2,817
Horizontal Gas	949	6,883
Otherwise Flared Solution Gas	151	135
Deep Oil Exploratory Well	-	12
Coalbed Methane	4	6
Total Royalty Program Adjustment	$ 465,982	$ 940,730

Continued...

Breakdown of Revenues...Continued

Revenue from Other Government Organizations

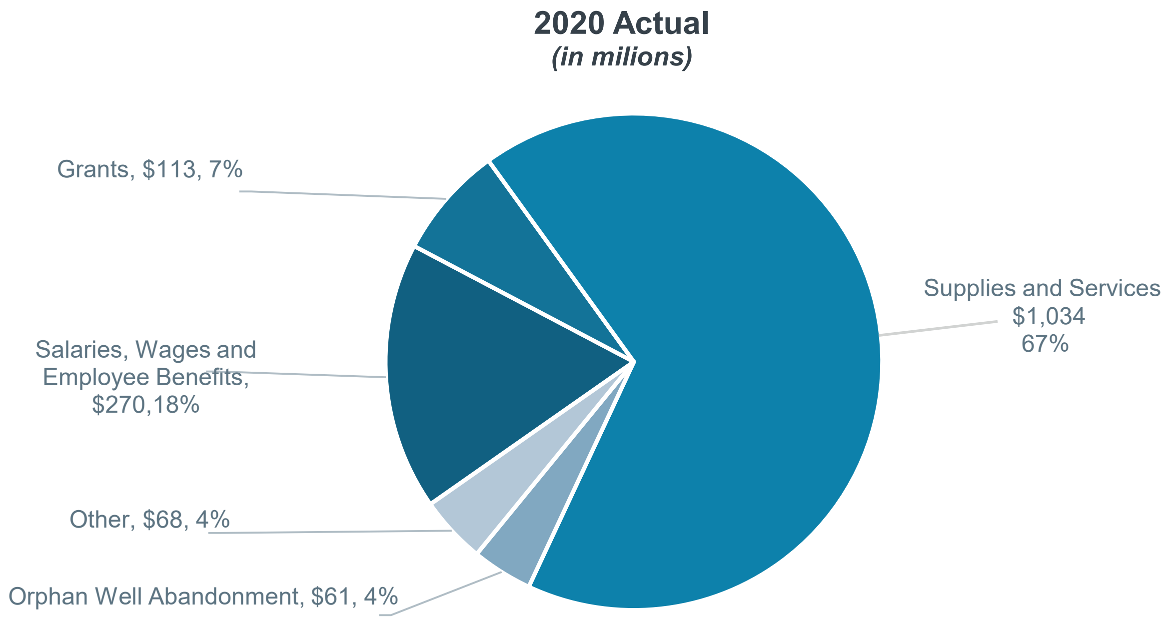
- Industry levies and licences totalled $331 million which primarily includes $299 million from AER and $31 million from AUC. Industry levies and licences were $10 million over budget due to an increase in orphan levies collected by AER as part of a three-year plan to address the increase in the number of abandoned wells.

Net Income/(Loss) from Government Business Enterprises

- Net losses from Government Business Enterprises is comprised of the net income from the Balancing Pool (BP) of $161 million offset by the net loss from the APMC of $2.68 billion.
- BP's net income of $161 million in 2019-20 reduced the accumulated deficit from an opening balance of $829 million to $667 million as of March 31, 2020. Lower than budgeted Net Income of $49 million was attributed to higher than expected cost of sales related to the PPA's. This was offset by higher than expected revenues due to an unanticipated increase in electricity prices.
- The APMC's net loss of $2.68 billion reduced accumulated equity from an opening accumulated deficit of $110 million to a closing accumulated deficit of $2.79 billion as of March 31, 2020. The net loss was driven primarily by:
  - Onerous contract provision associated with the Sturgeon Refinery Processing Agreement of $2.52 billion.
  - Delays in the Sturgeon Refinery meeting the anticipated commercial operation date (COD) of June 2018. This has resulted in a lack of operational revenues as anticipated.
  - The COD also coincided with the toll commencement date, which, per the agreement with the North West Redwater Partnership (NWRP), resulted in monthly debt tolls to be paid to NWRP (totalling $200 million) without offsetting revenues.

Expenses – Directly Incurred Detailed by Object

The following information presents expenses of the ministry that were directly incurred by object. The objective of disclosure of expenses by object is to provide information that is useful in evaluating the economic impact of government acquiring or consuming various types of resources.



- **Supplies and Services**, which represented 67 per cent of total operating expense, were the largest component of the ministry's operating expense ($1.03 billion). This consisted primarily of the costs related to the Crude by Rail program ($866 million). The remainder primarily consisted of ongoing supply requirements for the ministry (i.e., contracts and contract services, materials and supplies, and shared services provided by the Ministry of Service Alberta).
- **Salaries, Wages and Employee Benefits**, which represented 18 per cent of total operating expense, were the second largest component of the ministry's operating expense ($270 million) and primarily support the collection of revenue, development of resource policy, regulatory work provided by AER and AUC, and the overall support and management of ministry operations.
- **Grants**, which represented 7 per cent of total operating expense ($113 million), primarily consisted of payments related to Carbon Capture & Storage projects ($60 million) and the RRO rate cap program ($52 million).
- **Orphan Well Abandonment** expenses, totalling $61 million (four per cent), relate to the remittance of levies collected on behalf of the Orphan Well Association for the reclamation of abandoned wells, facilities and pipelines that are licensed to defunct licensees, as delegated by AER.
- **Other expenses**, totalling $68 million (four per cent), primarily consist of accretion expenses related to the off coal agreements ($28 million), allowances for doubtful accounts ($21 million) and amortization of tangible capital assets ($18 million).

Supplemental Financial Information

Liabilities

Gas Royalty Deposits

- The ministry requires that natural gas producers maintain a deposit, which in most cases is equal to one-sixth of the prior calendar year's royalties multiplied by the ratio of the long-term gas reference price on the date which the recalculation of the gas deposits is determined to the prior calendar year average gas reference price. The ministry does not pay interest on the deposits. As of March 31, 2020, the Ministry of Energy has gas royalty deposits of $178 million.

Coal Phase-Out Agreements

- On November 24, 2016, the Minister of Energy, on behalf of the province of Alberta, reached agreements with three coal-fired generators to cease operations on or before December 31, 2030. The coal-fired generation plants covered under agreements include: Sheerness 1 and 2; Genesee 1, 2, and 3; and Keephills 3.
- The Ministry of Energy will make payments totalling $97 million annually to the three generators. The first payment was made July 31, 2017 and payments will continue for the next 11 years. In return, the coal-fired plants named above will meet a number of conditions on an annual basis and will cease operations in the coal-fired electricity generation plants on or before December 31, 2030. These conditions are specific to each party, generally requiring each of the coal-fired generator owners to spend a minimum specified amount in the communities in which the plants were located, along with future specified value of investment and investment related activities in Alberta with respect to the electricity business.
- The present value of the remaining 11 payments, discounted at 3 per cent (representing the government's average 10-year bond rate at time of negotiations), is $1.07 billion. The amount of the draw down over the next five years and thereafter are as follows:

(in thousands)

	Annual Payment	Principal	Interest
2020-21	96,970	71,196	25,774
2021-22	96,970	73,357	23,613
2022-23	96,970	75,583	21,387
2023-24	96,970	77,877	19,093
2024-25	96,970	80,240	16,730
Thereafter	581,822	535,258	46,564
	$ 1,066,672	$ 913,511	$ 153,161

Equity in Government Business Enterprise

The following information presents the ministry's equity in government business enterprises as well as the contractual obligations, contingent liabilities, commitments and subsequent events of these entities.

Ministry of Energy
For the year ended March 31, 2020
(in thousands)

	2020			2019
	Alberta Petroleum Marketing Commission (APMC)	The Balancing Pool (BP)	Total	Total
Accumulated deficit beginning of year	$ (110,110)	$ (828,582)	$ (938,692)	$ (1,084,463)
Total Revenues	79,815	1,046,451	1,126,266	1,434,263
Total Expense	2,757,677	885,220	3,642,897	1,288,492
Net (loss)/income for the year	(2,677,862)	161,231	(2,516,631)	145,771
Total accumulated deficit and equity	$ (2,787,972)	$ (667,351)	$ (3,455,323)	$ (938,692)
Assets				
Cash and short-term investments	24,704	224,470	249,174	231,648
Term Loan	667,948	-	667,948	607,268
Other assets	125,855	384,493	510,348	848,850
Total assets	818,507	608,963	1,427,470	1,687,766
Liabilities				
Accounts payable (1)	150,596	234,817	385,413	256,322
Due to Government of Alberta (2)	924,614	702,498	1,627,112	1,530,756
Due to the Department of Energy	9,269	-	9,269	79,012
Other Liabilities (3)	2,522,000	338,999	2,860,999	760,368
Total liabilities	3,606,479	1,276,314	4,882,793	2,626,458
Total Equity	$ (2,787,972)	$ (667,351)	$ (3,455,323)	$ (938,692)

(1) Included in Accounts payable is $nil (2019 - $28.0 million) of payments in lieu of taxes that are payable to a municipal entity.

(2) Due to Government of Alberta consists of:

ii) short-term notes issued to the Province with maturity dates between April 2, 2020 and February 25, 2021 (2019 - May 30, 2019 and March 27, 2020) with annual interest charges ranging from 0.899% to 1.854% (2019 - 1.770% to 2.31%) by APMC, and;

ii) loan agreements with Treasury Board & Finance with maturity dates between May 1, 2020 and September 13, 2023 (2019 - May 30, 2019 and September 13, 2023) with annual interest charges ranging from 1.69% to 2.65% (2019 - 2.16% to 2.65%)

(3) Included in Other liabilities are Power Purchase Arrangement liabilities of $308 million (2019 - $736.9 million), Reclamation and abandonment provisions totalling $31.6 million (2019 - $23.4 million) and Sturgeon refinery Processing Agreement provision of $2.522 billion (2019 - $nil).

Continued...

Equity in Government Business Enterprise...Continued

Deemed Control

The Province created the Balancing Pool in 1998 to manage certain assets, liabilities, revenues and expenses arising from the transition to competition in Alberta's electric industry. The BP was established as a separate statutory corporation on June 1, 2003.

The BP is required to respond to certain extraordinary events during the operating period of all of the Power Purchase Arrangements (PPAs) such as force majeure, unit destruction, Buyer or Owner default or termination of a PPA. When a Buyer terminates a PPA, the BP will assume all remaining rights and obligations pursuant to the PPA assuming the PPA continues. The *Electric Utilities Act* requires the BP to manage generation assets in a commercial manner.

A series of legislative and regulatory changes and initiatives culminated in the ministry to be deemed in control of the BP for financial reporting purposes with an effective date of January 1, 2017.

Contractual Obligations, Contingent Liabilities and Commitments

a) North West Redwater Partnership Processing Agreement

On November 8, 2012, NWRP announced the sanctioning of the construction of Phase 1 of the Sturgeon Refinery which it will build, own and operate. The APMC has entered into agreements whereby NWRP will process and market Crown royalty bitumen, or equivalent volumes, collected pursuant to the Bitumen Royalty in Kind initiative in order to capture additional value within Alberta. NWRP will market the refined products (primarily ultra low sulphur diesel and low sulphur vacuum gas oil) on behalf of the APMC.

There is risk to the APMC under these agreements pertaining to the price differential between bitumen supplied as feedstock and marketed refined products, relative to the costs of the processing toll.

Under the Processing Agreement, after the Commercial Operations Date (COD) is achieved, the APMC is obligated to pay a monthly toll comprised of: senior debt; operating; class A subordinated debt; equity; and incentive fees on 37,500 barrels per day of bitumen (75 per cent of the project's feedstock). The Sturgeon Refinery did not attain COD in 2019, and per the Processing Agreement, the APMC and CNRL were required to start paying the debt toll at the Toll Commencement Date (June 1, 2018). APMC paid $201 million in debt tolls (2019 - $261 million). The APMC has expensed the debt tolls. The Processing Agreement has a term of 30 years starting with the Toll Commencement Date. The toll includes flow through costs as well as costs related to facility construction, estimated to be $10.1 billion (2019 - $9.9 billion).

The APMC has very restricted rights to terminate the agreement, and if it is terminated the APMC remains obligated to pay its share of the senior secured debt component of the toll incurred to date.

The nominal tolls under the processing agreement, assuming a $10.1 billion (2019 - $9.9 billion) Facility Capital Cost, market interest rates and 2 per cent operating cost inflation rate, are estimated below. The total estimated tolls have decreased by $0.283 billion (2019 - $0.689 billion increase) relative to March 2019, due primarily to lower debt tolls. As at March 31, 2020, NWRP has issued $6.35 billion (2019 - $6.35 billion) in bonds.

No value has been ascribed to the anticipated refining profits available to the APMC over the term of the agreement.

Continued...

Equity in Government Business Enterprise...Continued

Contractual Obligations, Contingent Liabilities and Commitments...Continued

b) North West Redwater Partnership Monthly Toll Commitment

The APMC has used judgment to estimate the toll commitments. The components of the toll are: senior debt, operating costs, class A subordinated debt, equity, and incentive fees. To calculate the toll, management has used estimates for factors including future interest rates, operating costs, oil prices (WTI and light/heavy differentials), refined product prices, gas prices and foreign exchange.

NWRP targets the refinery to come on stream to process bitumen feedstock with a commercial operations anticipated to commence late 2020. The future toll commitments are estimated to be:

2020-21	$	669,000
2021-22		1,008,000
2022-23		1,024,000
2023-24		1,028,000
2024-25		998,000
Thereafter		21,705,000
	$	26,432,000

c) Term Loan Provided to North West Redwater Partnership

As part of the Subordinated Debt Agreement with the Partnership, the APMC provided a $439 million loan (2019 - $439 million). These amounts plus the accrued interest will be repaid on a straight line basis over ten years by the Partnership beginning one year after commercial start-up of the Sturgeon Refinery. Upon initiation of commercial operations the total amount of the term loan will be adjusted to reflect an agreed equity to debt ratio.

While loans to the Partnership are outstanding, the APMC is entitled to a 25 percent voting interest on an Executive Leadership Committee, which is charged with overseeing and making decisions on the construction and start-up of the Sturgeon Refinery. Because of the 25 per cent voting interest, APMC has significant influence over the Partnership. However, the APMC has no equity ownership interest in the Partnership and does not account for the Sturgeon Refinery or its operations in its financial statements.

Under the agreements related to the Facility Capital Costs for the Sturgeon Refinery, the financing structure is required to be 80 per cent senior debt and 20 per cent equity/subordinated debt. The APMC is committed to provide 50 per cent of the subordinated debt required to meet this test. A final reconciliation of the amount of subordinated debt required will be done six months after Commercial Operation Date. The calculation of the 80/20 ratio allows for the deduction of cumulative debt service costs (accrued interest) at this time, while prior to this time the calculation does not allow for the deduction of accumulated debt service costs, which could result in a temporary need for additional subordinated debt lending by the APMC.

The APMC is forecasting to provide NWRP no additional subordinated debt in 2020 (2019 - $nil). In 2020 the APMC anticipates NWRP will repay $100 million (2019 - $90 million) to APMC as part of the final subordinated debt true-up six months after Commercial Operations Date.

Continued...

Equity in Government Business Enterprise...Continued

Contractual Obligations, Contingent Liabilities and Commitments...Continued

d) North West Redwater Partnership Processing Agreement Assessment

The APMC uses a cash flow model to determine if the unavoidable costs of meeting the obligations under the NWRP Processing Agreement exceed the economic benefits expected to be received. The model uses a number of variables to calculate a discounted net cash flow for APMC. Those variables include technical variables that arise from the design of the project such as pricing related variables including crude oil prices (WTI), heavy-light differentials, ultra-low sulphur diesel-WTI premiums, exchange rates, capital costs, operating costs, interest rates, discount rates; and operating performance compared to capacity.

Technical inputs may be estimated with reasonable accuracy for a particular operating plan; however, revenues and costs that depend upon market prices are challenging to estimate, particularly over long future time periods. The Processing Agreement has a term of 30 years and may be renewed for successive five year periods at APMC's option. In order to perform the onerous contract analysis, APMC management developed estimates for the key variables based on information from various sources including Government of Alberta, forecasts from global consultancies, reserve evaluation consultants and forward markets.

Based on the analysis as at the authorization date of these financial statements, APMC determined the agreement has a negative net present value and a provision is required. See Note (e) for further details.

For each subsequent year-end the APMC will perform this Processing Agreement assessment to determine the updated net present value. The balance sheet provision will be adjusted each year to the new net present value (either higher or lower) with the offset being recorded through the income statement. If the net present value turns positive then the reversal of the provision on the balance sheet is to zero (i.e. the contract cannot become an asset).

e) Sturgeon Refinery Processing Agreement Provision

APMC uses a cash flow model to assess if the net present value of the unavoidable costs related to the Processing Agreement with NWRP exceeds the economic benefits to be received. The model calculates the net present value of revenues from sales of refined products less feedstock costs and refinery tolls charged by NWRP under the Processing Agreement.

The net present value is most significantly influenced by two variables, pricing and on-stream factor. The definition of on-stream factor is the average percentage of time the refinery is operating.

APMC uses the Government of Alberta budget forecast values for WTI, WCS, condensate and foreign exchange to calculate the net present value. The single largest contributor to the decrease (81 per cent) in the net present value of the contract year over year is due to lower forecasted future WTI prices for the life of the refinery and a significant narrowing of the Diesel-WCS spread for 2020 to 2022. Diesel prices are calculated as a premium to WTI. Feedstock prices are calculated as percentage discount to WTI. Therefore, with lower WTI prices the net present value will be less.

Also contributing to the decrease in net present value is a lower expected on-stream factor.

The two most impactful pricing variables to the net present value of the contract are forecasted WTI prices and foreign exchange.

Continued...

Equity in Government Business Enterprise...Continued

Contractual Obligations, Contingent Liabilities and Commitments...Continued

e) Sturgeon Refinery Processing Agreement Provision...Continued

The net present value of the contract has a sensitivity to changes in WTI of +/- $157 million for every dollar change from the WTI forecast.

The net present value of the contract has a sensitivity to changes in foreign exchange, for every $0.01 the Canadian dollar changes from the forecast there is a +/- $109 million change to the net present value of the contract. If the Canadian dollar weakens in relation to the U.S. dollar, there is a positive impact to the net present value of the contract and conversely if the Canadian dollar strengthens in relation to the U.S. dollar, there is a negative impact to the net present value.

As at December 31, 2019, APMC recorded a Sturgeon Refinery Processing Agreement provision of $1.73 billion using an appropriately dated pricing forecast. Those prices were very volatile from December 31, 2019 to March 31, 2020 and we updated the pricing forecast and calculated the provision to be $2.52 billion.

f) Crude-by-Rail Program

APMC has used judgment in determining whether it is acting as a principal or agent with respect to crude-by-rail activities. Under the previous government on February 14, 2019, APMC received a letter from the Minister of Energy directing APMC, as an agent of the Crown, "to proceed with execution of the crude-by-rail program". Then under the current government APMC, was directed on May 24th, 2019, "take all steps possible to explore best options for assigning crude-by-rail program contracts entered into by the APMC to third parties, and to enter into assignment agreements as expeditiously as possible with third parties on commercial terms, provided that the final terms have been approved by the Government". While the APMC entered into the contracts, all financial risk belongs to the Crown. Therefore, the gross inflows and economic benefits of the crude-by-rail program are considered collected on behalf of the Crown and are not recognized as revenue.

g) KXL Investment

An Investment Agreement between TransCanada Pipelines Limited (TCPL) and the APMC was executed on March 31, 2020. APMC, through newly created subsidiaries, has agreed to provide financial support for the construction of the KXL Expansion pipeline. APMC will extend US$5.3 billion of funding support beginning with an equity commitment of up to US$1.06 billion in 2020. The balance of the support, commencing January 1, 2021, will be in the form of a debt guarantee to backstop TCPL's financing for the KXL Expansion pipeline.

The APMC acquired its initial interest in the KXL Expansion Pipeline effective March 31, 2020 in exchange for its agreement to make initial equity contributions of $102,157(US$48,245 and $33,927) by way of cash contributions of US$29,081 and $13,143 and through subsequent loans from TCPL for the month of April 2020, of an additional US$19,164 and $20,784. APMC satisfied the payment of its initial equity contributions on April 3, 2020. In addition, TCPL is lending APMC the funds required to make APMC's monthly funding contributions. APMC has executed non-interest bearing promissory notes to TCPL in connection with this funding. APMC will repay the loans to TCPL in six equal monthly installments, commencing July 2020, concurrent with APMC's monthly contributions.

Continued...

Equity in Government Business Enterprise...Continued

Contractual Obligations, Contingent Liabilities and Commitments...Continued

g) KXL Investment…Continued

The APMC will earn accretion on its equity contributions paid until March 31, 2026 at a rate of 6 per cent per annum, increasing to 10 per cent per annum on and after September 1, 2033, if the KXL pipeline is not in-service, with a minimum guaranteed rate of 4 per cent per annum when APMC's equity contributions are repurchased by TCPL. In addition, APMC will earn a loan guarantee fee (0.50 per cent of TCPL's debt outstanding, subject to escalation if the loan guarantee is outstanding 480 days following project completion) starting in 2021 when TCPL obtains debt financing. Approximately one year after project completion, TCPL will pay to APMC the value of the outstanding equity contributions and accretion earned thereon. TCPL will pay the loan guarantee fee at the same time as APMC's debt guarantees are released. This is also anticipated to occur approximately one year after project completion.

h) Retroactive Line Loss Adjustment

In December 2017, the Alberta Utilities Commission (AUC) reached its decision on Proceeding 790. As a result, BP will incur additional charges as a result of the retroactive adjustments to line loss factors in relation to the various PPAs. An estimated provision in the amount of $68.4 million (2019 – $45.5 million) has been recorded in trade payable and other accrued liabilities for the retroactive line loss adjustment as a result of the AUC's December 2017 decision. The estimate has been prepared using the Module B method based on Incremental Loss Factors with generation scaling.

The various matters approved by the AUC regarding the retroactive line loss adjustments are under appeal with the Court of Appeal, including the retroactive nature of the adjustments and prospective line loss factors used to calculate the adjustment. The quantum of any retroactive adjustment will be dependent upon the methodology finally adopted and approved. Given the uncertainty of the final methodology, BP estimates may be higher or lower than the current estimate reflected in these financial statements.

i) Reclamation and Abandonment

TransAlta has submitted an application to the AUC to decommission Sundance A and is seeking $41.4 million in funding from the Balancing Pool. The Balancing Pool disagrees with several aspects of the application. The Balancing Pool has a provision of $22.0 million to decommission Sundance A. The final amount due will be determined by the AUC.

j) Legal Claim

On June 12, 2019, the Balancing Pool received a statement of claim from a power producer seeking $17.5 million in damages from the Balancing Pool. The Balancing Pool has filed a statement of defense and will vigorously defend its position. The Balancing Pool is of the opinion the statement of claim is without merit. Furthermore, Section 92 of the Electric Utilities Act provides the Balancing Pool with strong liability protection for such claims. As at March 31, 2020, no contingent liability has been recorded, as the Balancing Pool does not expect a material outflow.

Continued...

Equity in Government Business Enterprise...Continued

Subsequent Events

Short-Term Debt

On April 2, 2020, APMC replaced its short-term debt of $120.4 million originally issued April 4, 2019 with 3 new short-term debts. The first debt of $20.963 million was at 0.692 per cent interest due July 3, 2020. The second debt of $24.915 million was at 0.759 per cent interest due September 14, 2020. The third debt of $74.726 million was at 0.731 per cent due October 2, 2020.

On April 3, 2020, APMC borrowed $13.143 million of short-term debt from Treasury Board and Finance at an effective interest rate of 0.6998 per cent due April 2, 2021.

On April 3, 2020, APMC borrowed $41.127 million of short-term debt from Treasury Board and Finance at an effective interest rate of 1.2724 per cent due January 28, 2021.

On April 23, 2020, APMC borrowed $17.299 million of short-term debt from Treasury Board and Finance and also replaced its short-term debts of $17.201 million originally issued April 25, 2019. The two debts were combined into one new short term debt of $34.809 million at 0.550 per cent interest due April 22, 2021.

On May 22, 2020, APMC borrowed $17.000 million of short term debt from Treasury Board and Finance and replaced its short term debts of $16.600 million originally issued May 24, 2019. These two debts were combined into one new short term debt of $34.854 million at 0.420 per cent interest due May 21, 2021.

On May 28, 2020, APMC replaced its short term debt of $21.623 million originally issued May 30, 2019 with new short term debt of $19.918 million at 0.410 per cent interest due May 28, 2021.

On June 22, 2020, APMC borrowed $35.874 million of short term debt from Treasury Board and Finance at an effective interest rate of 0.350 per cent due June 22, 2021.

On June 23, 2020, APMC replaced two short term debts of $15.500 million and $42.000 million originally issued June 25, 2019 with one new short term debt of $35.875 million at 0.350 per cent interest due June 21, 2021.

On June 25, 2020, APMC borrowed $22.323 million of short term debt from Treasury Board and Finance at an effective interest rate of 0.350 per cent due June 21, 2021.

On June 26, 2020, APMC repaid Treasury Board and Finance the $13.460 million to settle two short term debts of $8.460 million and $5.000 million originally issued June 28, 2019 and Mar 27, 2020 respectively.

On June 30, 2020, APMC replaced its short term debt of $20.000 million originally issued March 30, 2020 with new short term debt of $20.030 million at 0.350 per cent interest due June 30, 2021.

On July 2, 2020, APMC borrowed $99.754 million of short term debt from Treasury Board and Finance at an effective interest rate of 0.330 per cent due April 1, 2021.

On July 2, 2020, APMC borrowed $54.118 million of short term debt from Treasury Board and Finance at an effective interest rate of 0.340 per cent due June 28, 2021.

On July 3, 2020, APMC replaced its short term debt of $21.000 million originally issued April 2, 2020 with new short term debt of $21.030 million at 0.340 per cent interest due June 28, 2021.

Continued...

Equity in Government Business Enterprise...Continued

Subsequent Events...Continued

Coronavirus

Since March 31, 2020, the outbreak of the coronavirus has caused global economic uncertainty, which may affect prices and demand for the Sturgeon Refinery's refined products, temporarily disrupt supply chain and transportation services or result in a temporary loss of skilled labour. This may cause temporary operational reductions and higher costs. The duration and severity of these developments remain unknown but may have an impact on the financial results of APMC in future periods.

Similarly, COVID-19 may affect the cost and timing of when the KXL Expansion pipeline comes into service. The duration and severity of these developments remain unknown but may have an impact on the financial results of APMC in future periods.

Sturgeon Refinery

In April 2020, the Refinery successfully transitioned from primarily processing synthetic crude feedstock to bitumen feedstock and reached commercial operations in May 2020. As a result, the criteria to achieve a June 1, 2020 Commercial Operation Date ("COD") was achieved. COD is defined in the Processing Agreements as "the first Day of the Month immediately following the Month, in which, for the first time, the Facility has for 30 consecutive Days (which may span more than one Month) received and processed into the products intended to be produced therefrom a quantity of Bitumen that is not less than 50 per cent of the Design Capacity.

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Auditor General
OF ALBERTA

Independent Auditor's Report

To the Board of Directors of the Alberta Energy Regulator

Report on the Financial Statements

Qualified Opinion

I have audited the financial statements of the Alberta Energy Regulator (the AER), which comprise the statement of financial position as at March 31, 2020, and the statements of operations, change in net debt, and cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In my opinion, except for the effects of the matter described in the Basis for qualified opinion section of my report, the accompanying financial statements present fairly, in all material respects, the financial position of the AER as at March 31, 2020, and the results of its operations, its changes in net debt, and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Basis for qualified opinion

The AER has not appropriately presented and disclosed the nature of its relationship and its transactions with ICORE Energy Services (ICORE NFP), an organization created by the AER and incorporated under the *Canada Not-for-profit Corporations Act*. I examined the nature of the relationship between the AER and ICORE NFP, and the related transactions, and determined that under Canadian public sector accounting standards the AER controlled ICORE NFP from May 17, 2017 until December 19, 2018, when the AER resigned its membership and control of ICORE NFP.

The AER concluded that ICORE NFP is not controlled and presents the relationship and transactions with ICORE NFP as a related party in schedule 4 - related party transactions. Because the AER controlled ICORE NFP, its financial results up to December 19, 2018 should have been consolidated into the AER's financial statements. Had the AER consolidated ICORE NFP, the AER's statement of operations for the year ended March 31, 2019 would have additional ICORE Energy Services (NFP) revenue of $l.0 million and additional ICORE Energy Services (NFP) expense of $0.7 million. Further, expenses reported on the AER's statement of operations for the year ended March 31, 2019 classified as Energy Regulation should be $2.3 million lower and expenses classified as ICORE Energy Services (NFP) should be $2.3 million higher. Schedule 4 – related party transactions does not accurately describe the nature of the relationship between the AER and ICORE NFP as a controlled entity. The statement of operations for the year ended March 31, 2020 is not misstated because the AER did not control ICORE NFP after December 19, 2018.

I conducted my audit in accordance with Canadian generally accepted auditing standards. My responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of my report. I am independent of the AER in accordance with the ethical requirements that are relevant to my audit of the financial statements in Canada, and I have fulfilled my other ethical responsibilities in accordance with these requirements. I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my qualified opinion.

Other information

Management is responsible for the other information. The other information comprises the information included in the *Annual Report*, but does not include the financial statements and my auditor's report thereon. The *Annual Report* is expected to be made available to me after the date of this auditor's report.

My opinion on the financial statements does not cover the other information and I do not express any form of assurance conclusion thereon.

In connection with my audit of the financial statements, my responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or my knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work I will perform on this other information, I conclude that there is a material misstatement of this other information, I am required to communicate the matter to those charged with governance.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with Canadian public sector accounting standards, and for such internal control as management determines is necessary to enable the preparation of the financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the AER's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless an intention exists to liquidate or to cease operations, or there is no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the AER's financial reporting process.

Auditor's responsibilities for the audit of the financial statements

My objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes my opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, I exercise professional judgment and maintain professional skepticism throughout the audit. I also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for my opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the AER's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the AER's ability to continue as a going concern. If I conclude that a material uncertainty exists, I am required to draw attention in my auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify my opinion. My conclusions are based on the audit evidence obtained up to the date of my auditor's report. However, future events or conditions may cause the AER to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

I communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that I identify during my audit.

[Original signed by]

W. Doug Wylie FCPA, FCMA, ICD.D
Auditor General

June 18, 2020
Edmonton, Alberta

Statement of Operations

Aberta Energy Regulator
Year ended March 31, 2020

	2020		2019
	Budget (Note 4, Schedule 3)	Actual	Actual
		(in thousands)	
Revenues			
Administration fees	$ 232,722	$ 233,393	$ 253,149
Orphan well abandonment levy and fees	55,813	61,039	45,959
Information, services and fees	3,542	4,693	5,831
ICORE Energy Services (NFP) (Schedule 4)		-	3,134
Investment income	867	555	2,281
	292,944	299,680	310,354
Expenses (Note 2 and Schedule 1)			
Energy regulation	236,331	264,248	257,903
Orphan well abandonment (Note 5)	55,813	61,039	45,959
ICORE Energy Services (NFP) (Schedule 4)		-	1,548
	292,144	325,287	305,410
Annual operating surplus (deficit)	800	(25,607)	4,944
Accumulated surplus at beginning of year	66,517	66,517	61,573
Accumulated surplus at end of year	$ 67,317	$ 40,910	$ 66,517

The accompanying notes and schedules are part of these financial statements.

Statement of Financial Position

Aberta Energy Regulator
As at March 31, 2020

	2020	2019
	(in thousands)	
Financial assets		
Cash and cash equivalents (Note 6)	$ -	$ 19,740
Accounts receivable (Note 7)	1,920	7,484
Pension assets (Note 12)	1,505	2,141
	3,425	29,365
Liabilities		
Bank indebtedness (Note 6)	812	-
Accounts payable and accrued liabilities (Note 8)	17,955	20,505
Payable to Orphan Well Association	609	1,928
Deferred lease incentives (Note 10)	15,949	17,568
	35,325	40,001
Net debt	(31,900)	(10,636)
Non-financial assets		
Tangible capital assets (Note 13)	63,105	66,415
Prepaid expenses and other assets	9,705	10,738
	72,810	77,153
Net assets		
Accumulated surplus (Note 14)	$ 40,910	$ 66,517

Contingent liabilities (Note 15)
Contractual obligations (Note 16)

The accompanying notes and schedules are part of these financial statements.

Statement of Change in Net Debt

Aberta Energy Regulator
Year ended March 31, 2020

	2020		2019
	Budget (Note 4, Schedule 3)	Actual	Actual
		(in thousands)	
Annual operating surplus (deficit)	$ 800	$ (25,607)	$ 4,944
Acquisition of tangible capital assets (Note 13)	(12,300)	(12,704)	(19,145)
Amortization of tangible capital assets (Note 13)	11,500	15,947	15,329
Loss on disposal and write-down of tangible capital assets		67	119
Decrease in prepaid expenses and other assets		1,033	1,048
(Increase)/decrease in net debt	-	(21,264)	2,295
Net debt at beginning of year	(10,636)	(10,636)	(12,931)
Net debt at end of year	$ (10,636)	$ (31,900)	$ (10,636)

The accompanying notes and schedules are part of these financial statements.

Statement of Cash Flows

Aberta Energy Regulator
Year ended March 31, 2020

	2020	2019
	(in thousands)	
Operating transactions		
Annual operating (deficit) surplus	$ (25,607)	$ 4,944
Non-cash items included in annual operating (deficit) surplus:		
Amortization of tangible capital assets (Note 13)	15,947	15,329
Loss on disposal and write-down of tangible capital assets	67	119
Change in pension assets	636	(1,403)
Amortization of deferred lease incentives (Note 10)	(1,619)	(1,631)
	(10,576)	17,358
Decrease in accounts receivable	5,564	64
Decrease in prepaid expenses and other assets	1,033	1,048
(Decrease)/increase in accounts payable and accrued liabilities	(2,550)	3,482
(Decrease)/increase in payable to Orphan Well Association	(1,319)	1,122
Additions to deferred lease incentives (Note 10)	-	167
Cash (applied to) provided by operating transactions	(7,848)	23,241
Capital transactions		
Acquisition of tangible capital assets (Note 13)	(12,704)	(19,145)
Cash applied to capital transactions	(12,704)	(19,145)
Financing transactions		
Proceeds from line of credit	64,587	-
Debt repayment	(63,775)	-
Cash provided by financing transactions	812	-
(Decrease)/increase in cash and cash equivalents	(19,740)	4,096
Cash and cash equivalents at beginning of year	19,740	15,644
Cash and cash equivalents at end of year	$ -	$ 19,740

The accompanying notes and schedules are part of these financial statements.

Notes to the Financial Statements

Aberta Energy Regulator
March 31, 2020

Note 1 AUTHORITY

The Alberta Energy Regulator (AER) is an independent and quasi-judicial organization of the Government of Alberta. The AER operates under the *Responsible Energy Development Act.* The AER's mandate provides for the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources over their entire life cycle. This includes allocating and conserving water resources, managing public lands, and protecting the environment while providing economic benefits for all Albertans. The AER is exempt from income taxes under the Income Tax Act.

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES

These financial statements are prepared in accordance with Canadian Public Sector Accounting Standards (PSAS).

Basis of financial reporting

Revenues

All revenues are reported on the accrual basis of accounting. Cash received for which services have not been provided by year end is recognized as unearned revenue and recorded in accounts payable and accrued liabilities.

Investment Income

Investment income includes interest income.

Expenses

Expenses are reported on an accrual basis. The cost of all goods consumed and services received during the year is expensed.

Employee future benefits

The AER maintains its own defined benefit Senior Employees Pension Plan (SEPP) and two supplementary pension plans to compensate senior staff who do not participate in the government management pension plans. Retirement benefits are based on each employee's years of service and remuneration.

Pension assets represent the sum of the accumulated cash contributions less the sum of the current and prior years' pension expense.

Accrued benefit obligations are actuarially determined using the projected benefit method prorated on length of service and management's best estimate of expected plan investment performance, projected employees' compensation levels and retirement age of employees.

Accrued benefit obligations and pension benefit costs for the year are calculated using the expected rate of return on plan assets as the discount rate, which is determined using market values of plan assets.

Actuarial gains and losses are amortized over the average remaining service period of the active employees, which is 10.9 years (2019 - 10.9 years).

Past service cost arising from plan amendments is accounted for in the period of the plan amendments.

Gains and losses determined upon a plan curtailment are accounted for in the period of curtailment.

The AER participates in the Government of Alberta's multi-employer pension plans: Management Employees Pension Plan, Public Service Pension Plan and Supplementary Retirement Plan for Public Service Managers. Defined contribution plan accounting is applied to these plans as the AER has insufficient information to apply defined benefit plan accounting. Accordingly, pension expense comprises employer contributions to the plans that are required for its employees during the year, which are calculated based on actuarially pre-determined amounts that are expected to provide the plans' future benefits.

Notes to the Financial Statements

Aberta Energy Regulator
March 31, 2020

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (continued)

Basis of financial reporting (continued)

Valuation of financial assets and liabilities

The AER's financial assets and liabilities are generally measured as follows:

Financial Statement Component	Measurement
Cash and cash equivalents	Cost
Accounts receivable	Lower of cost or net recoverable value
Bank indebtedness	Cost
Accounts payable and accrued liabilities	Cost
Payable to the Orphan Well Association	Cost
Deferred lease incentives	Amortized cost

The AER has not designated any financial assets or liabilities in the fair value category, has no significant foreign currency transactions and does not hold any derivative contracts. The AER has no significant remeasurement gains or losses and consequently has not presented a statement of remeasurement gains and losses.

Financial assets

Financial assets are assets that could be used to discharge existing liabilities or finance future operations and are not for consumption in the normal course of operations.

Financial assets are the AER's financial claims on external organizations and individuals at the year end.

Cash and cash equivalents

Cash comprises cash on hand and demand deposits.

Accounts receivable

Accounts receivable are recognized at the lower of cost or net recoverable value. A valuation allowance is recognized when recovery is uncertain.

Liabilities

Liabilities are present obligations of the AER to external organizations and individuals arising from past transactions or events occurring before the year end, the settlement of which is expected to result in the future sacrifice of economic benefits. They are recognized when there is an appropriate basis of measurement and management can reasonably estimate the amounts. Liabilities include all financial claims payable by the AER at fiscal year end.

Bank indebtedness

Bank indebtedness comprises the amount outstanding for the revolving line of credit.

Deferred lease incentives

Deferred lease incentives, consisting of leasehold improvement costs, reduced rent benefits and rent-free periods, are amortized on a straight-line basis over the term of the leases.

Notes to the Financial Statements

Aberta Energy Regulator
March 31, 2020

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (continued)

Basis of financial reporting (continued)

Environmental Liabilities

Contaminated sites are a result of contamination of a chemical, organic or radioactive material or live organism that exceeds an environmental standard, being introduced into soil, water or sediment.

A liability for remediation of contaminated sites from an operation(s) that is no longer in productive use and may be due to unexpected events resulting in contamination, is recognized net of any expected recoveries, when all of the following criteria are met:

- an environmental standard exists;
- contamination exceeds the environmental standard;
- the AER is directly responsible or accepts responsibility;
- it is expected that future economic benefits will be given up; and
- a reasonable estimate of the amount can be made.

Non-financial assets

Non-financial assets are acquired, constructed or developed assets that do not normally provide resources to discharge existing liabilities, but instead:

- are normally employed to deliver AER services;
- may be consumed in the normal course of operations; and
- are not for sale in the normal course of operations.

Non-financial assets of the AER include tangible capital assets, prepaid expenses and other assets.

Tangible capital assets

Tangible capital assets are recognized at cost less accumulated amortization, which includes amounts that are directly related to the acquisition, design, construction, development, improvement or betterment of the assets. Cost includes overhead directly attributable to construction and development of the asset.

The cost of the tangible capital assets, excluding land, is amortized over their estimated useful lives as follows:

Leasehold improvements	Straight line	Term of the lease
Furniture and equipment	Straight line	5 - 12 years
Computer hardware	Straight line	4 years
Computer software - purchased	Straight line	4 years
Computer software - developed	Declining balance	5 years

Amortization is only expensed when the tangible capital asset is put into service.

Work-in-progress, which may include developed computer software and leasehold improvements, is not amortized until a project is complete and the asset is put into service.

Tangible capital assets are written down when conditions indicate that they no longer contribute to the AER's ability to provide goods and services, or when the value of future economic benefits associated with the tangible capital assets is less than their net book value. The net write-downs are accounted for as an expense in the Statement of Operations.

Notes to the Financial Statements

Aberta Energy Regulator
March 31, 2020

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (continued)

Basis of financial reporting (continued)

Prepaid expenses

Prepaid expenses are recognized at cost and amortized based on the terms of the agreements.

Measurement uncertainty

Measurement uncertainty exists when there is a variance between the recognized or disclosed amount and another reasonably possible amount, whenever estimates are used. The amounts recognized for amortization of tangible capital assets are based on estimates of the useful life of the related assets. Accrued defined benefit obligations are subject to measurement uncertainty due to the use of actuarial assumptions. The resulting estimates are within reasonable limits of materiality and are in accordance with the AER's significant accounting policies. In addition, estimates for contingent liabilities are subject to measurement uncertainty. These estimates are recorded when the contingency is determined to be likely and measurable however the actual amount of any settlement may vary from the estimate recorded.

Note 3 FUTURE ACCOUNTING CHANGES

The Public Sector Accounting Board has approved the following accounting standards:

PS 3280 Asset Retirement Obligations (effective April 1, 2021)

This standard provides guidance on how to account for and report liabilities for retirement of tangible capital assets.

PS 3400 Revenue (effective April 1, 2022)

This standard provides guidance on how to account for and report on revenue, and specifically, it addresses revenue arising from exchange transactions and unilateral transactions.

Management is currently assessing the impact of these standards on the financial statements.

Note 4 BUDGET

The budget and budget adjustments reflected on Schedule 3 have been approved by the Government of Alberta.

Note 5 ORPHAN WELL ABANDONMENT

(in thousands)

The Government of Alberta has delegated the authority to manage the abandonment and reclamation of wells, facilities and pipelines that are licensed to defunct licensees to the Alberta Oil and Gas Orphan Abandonment and Reclamation Association (Orphan Well Association). The AER transfers orphan well abandonment levy and application fees to the Orphan Well Association. During the year ended March 31, 2020, the AER collected $60,345 (2019 - $45,379) in levies and $694 (2019 - $580) in application fees.

Notes to the Financial Statements

Aberta Energy Regulator
March 31, 2020

Note 6 CASH AND CASH EQUIVALENTS AND BANK INDEBTEDNESS

(in thousands, unless otherwise noted)

	2020	2019
Cash and cash equivalents	$ -	$ 19,740
Bank indebtedness	(812)	-
	$ (812)	$ 19,740

Cash and cash equivalents are held in an account with a Canadian chartered bank and earn interest calculated based on the average monthly cash balance. The funds are available to be withdrawn upon request. During the year ended March 31, 2020, the AER earned interest at an annual average rate of 2.1% (2019 - 2.1%).

The AER has an unsecured $75 million (2019 - $50 million) revolving line of credit. Amounts borrowed can only be applied to general corporate purposes and exclude the funding of capital expenditures.

Bank advances on the line of credit are payable on demand and bear interest at a rate of prime less 0.75% (2019 - prime less 0.5%). For the year ended March 31, 2020, interest expense on the revolving line of credit was $143 (2019 - $nil).

Note 7 ACCOUNTS RECEIVABLE

(in thousands)

Accounts receivable are unsecured and non-interest bearing.

	2020			2019
	Gross amount	Allowance for doubtful accounts	Net recoverable value	Net recoverable value
Accounts receivable - general	$ 5,084	$ (3,164)	$ 1,920	$ 5,314
Accounts receivable - ICORE Energy Services (NFP)	-	-	-	2,170
	$ 5,084	$ (3,164)	$ 1,920	$ 7,484

Note 8 ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

(in thousands)

	2020	2019
Accounts payable	$ 3,052	$ 3,823
Accrued liabilities	14,177	14,719
Unearned revenue	726	1,963
	$ 17,955	$ 20,505

Notes to the Financial Statements

Aberta Energy Regulator
March 31, 2020

Note 9 FINANCIAL INSTRUMENTS

(in thousands)

The AER has the following financial instruments: cash and cash equivalents, accounts receivable, bank indebtedness, accounts payable and accrued liabilities, and payable to the Orphan Well Association.

Financial risk management

The AER has exposure to the following risks from its use of financial instruments:

(a) Liquidity risk

Liquidity risk is the risk that the AER will encounter difficulty in meeting obligations associated with its financial liabilities. Liquidity requirements of the AER are met primarily through the collection of funding at the beginning of the year to fund operating expenses and capital expenditures throughout the year. The AER manages liquidity risk by having established budget processes and regularly monitoring cash flows to ensure the necessary funds are on hand to fulfill upcoming obligations. In addition, the AER maintains a revolving line of credit which provides financial flexibility to allow the AER to meet its obligations if funding cannot be collected on a timely basis. As at March 31, 2020, the AER had bank indebtedness of $812 (2019 - $nil).

(b) Credit risk

The AER is exposed to credit risk from potential non-payment of accounts receivable. A substantial portion of the AER's accounts receivable includes balances due from operators in the oil and gas industry, and is subject to normal industry credit risk. The AER regularly monitors the financial status of operators and assesses the collectability of accounts receivable. The AER's maximum exposure to credit risk is limited to the carrying amount of accounts receivable presented in the Statement of Financial Position at the reporting date. The AER established a valuation allowance that corresponds to the specific credit risk of operators, historical trends and economic circumstances.

Note 10 DEFERRED LEASE INCENTIVES

(in thousands)

The AER has entered into various lease agreements which provide for lease incentives comprising reduced rent benefits, rent-free periods and leasehold improvement costs. These amounts are included in deferred lease incentives in the Statement of Financial Position and are amortized on a straight-line basis over the term of the lease.

	2020			2019
	Leasehold improvement costs	Reduced rent benefits and rent-free periods	Total	Total
Balance at beginning of year	$ 14,143	$ 3,425	$ 17,568	$ 19,032
Additions	-	-	-	167
Amortization	(1,252)	(367)	(1,619)	(1,631)
Balance at end of year	$ 12,891	$ 3,058	$ 15,949	$ 17,568

Note 11 ENVIRONMENTAL LIABILITIES

(in thousands)

As at March 31, 2020, the AER is not responsible, nor has it accepted responsibility, for performing remediation work at contaminated sites. As at March 31, 2020, the AER's liability for contaminated sites was $nil (2019 - $nil).

Notes to the Financial Statements

Aberta Energy Regulator
March 31, 2020

Note 12 EMPLOYEE FUTURE BENEFITS

(in thousands, unless otherwise noted)

The AER participates in the Government of Alberta's multi-employer pension plans: Management Employees Pension Plan, Public Service Pension Plan and Supplementary Retirement Plan for Public Service Managers. For the year ended March 31, 2020, the expense for these pension plans is equal to the contribution of $15,533 (2019 - $16,598). The AER is not responsible for future funding of the plan deficit other than through contribution increases.

In addition, the AER maintains its own defined benefit Senior Employees Pension Plan (SEPP) and two supplementary pension plans to compensate senior staff who do not participate in the government management pension plans. Retirement benefits are based on each employee's years of service and remuneration.

All the information presented in the note below is related to the AER's defined benefit pension plans.

The effective date of the most recent actuarial funding valuation for SEPP was December 31, 2018. The accrued benefit obligation as at March 31, 2020 is based on the extrapolation of the results of this valuation. The effective date of the next required funding valuation for SEPP is December 31, 2021.

Pension plan assets are valued at market values. During the year ended March 31, 2020, the weighted average actual return on plan assets was -3.7% (3.7% in 2019).

Significant weighted average actuarial and economic assumptions used to value accrued benefit obligations and pension benefit costs were as follows:

Accrued benefit obligations	2020	2019
Discount rate	4.8%	5.1%
Rate of compensation increase	0% until March 31, 2021, 3.5% thereafter	0% until Sep 30, 2019, 3.5% thereafter
Long-term inflation rate	2.0%	2.0%

Pension benefit costs for the year	2020	2019
Discount rate	5.1%	5.0%
Expected rate of return on plan assets	5.1%	5.0%
Rate of compensation increase	0% until Sep 30, 2019, 3.5% thereafter	0% until Sep 30, 2019, 3.5% thereafter

The funded status and amounts recognized in the Statement of Financial Position were as follows:

	2020	2019
Market value of plan assets	$ 65,442	$ 67,789
Accrued benefit obligations	(72,461)	(63,836)
Plan (deficit) surplus	(7,019)	3,953
Unamortized actuarial losses (gains)	8,524	(1,812)
Pension assets	$ 1,505	$ 2,141

Notes to the Financial Statements

Aberta Energy Regulator
March 31, 2020

Note 12 EMPLOYEE FUTURE BENEFITS (continued)
(in thousands, unless otherwise noted)

The pension benefit costs for the year included the following components:

	2020	2019
Current period benefit cost	$ 4,326	$ 4,123
Interest cost	3,382	3,097
Expected return on plan assets	(3,574)	(3,252)
Loss on curtailments	1,342	-
Unamortized (gains) recognized in curtailments	(172)	-
Amortization of actuarial (gains) losses	(53)	279
	$ 5,251	$ 4,247

Additional information about the defined benefit pension plans is as follows:

	2020	2019
AER contributions	$ 4,616	$ 5,649
Employees' contributions	839	898
Benefits paid	5,325	3,028

The asset allocation of the defined benefit pension plans' investments was as follows:

	2020	2019
Equity securities	42.3%	45.8%
Debt securities	24.7%	22.8%
Alternatives	19.6%	18.0%
Other	13.4%	13.4%
	100.0%	100.0%

During the year, the AER underwent a re-organization and reduced the number of employees to become more effective, efficient and resilient in the delivery of its mandate and to meet the reduced budget targets. This resulted in a curtailment due to the reduction in the number of active employees in the AER's maintained defined benefit pension plans. The curtailment impact is a $1,342 (2019 - $nil) increase in the accrued benefit obligations recognized immediately through pension expense.

Notes to the Financial Statements

Aberta Energy Regulator
March 31, 2020

Note 13 TANGIBLE CAPITAL ASSETS
(in thousands)

	2020					2019
	Land	**Leasehold improvements**	**Furniture and equipment**	**Computer hardware and software**	**Total**	**Total**
Estimated useful life	Indefinite	Term of the lease	5-12 years	4-5 years		
Historical cost[1]						
Beginning of year	$ 282	$ 45,724	$ 13,615	$ 137,253	$ 196,874	$ 186,834
Additions	-	11	3	12,690	12,704	19,145
Disposals, including write-downs	-	-	(506)	(6,523)	(7,029)	(9,105)
	282	45,735	13,112	143,420	202,549	196,874
Accumulated amortization						
Beginning of year	$ -	$ 17,444	$ 8,933	$ 104,082	$ 130,459	$ 124,116
Amortization expense	-	2,735	1,000	12,212	15,947	15,329
Effect of disposals, including write-downs	-	-	(506)	(6,456)	(6,962)	(8,986)
	-	20,179	9,427	109,838	139,444	130,459
Net book value at March 31, 2020	$ 282	$ 25,556	$ 3,685	$ 33,582	$ 63,105	
Net book value at March 31, 2019	$ 282	$ 28,280	$ 4,682	$ 33,171		$ 66,415

(1) As at March 31, 2020, historical cost of computer hardware and software includes work-in-progress totalling $76 (2019 - $5,726).

Note 14 ACCUMULATED SURPLUS
(in thousands)

The accumulated surplus of the AER is calculated as the sum of the AER's net debt and its non-financial assets. The accumulated surplus represents the net assets of the AER and comprises the following:

	2020			2019
	Investments in tangible capital assets[a]	**Unrestricted net assets (debt)**	**Total**	**Total**
Balance at beginning of year	$ 52,272	$ 14,245	$ 66,517	$ 61,573
Annual operating (deficit) surplus	-	(25,607)	(25,607)	4,944
Net investment in capital assets[a]	(2,058)	2,058	-	-
Balance at end of year	$ 50,214	$ (9,304)	$ 40,910	$ 66,517

(a) Excludes leasehold improvement costs received by the AER as a lease incentive and related amortization.

Notes to the Financial Statements

Aberta Energy Regulator
March 31, 2020

Note 15 CONTINGENT LIABILITIES

(in thousands)

The AER is involved in legal matters where damages are being sought. These matters may give rise to contingent liabilities.

Accruals have been made in specific instances where it is likely that losses will be incurred based on a reasonable estimate. As at March 31, 2020, accruals totalling $630 (2019 - $91) have been recognized as a liability.

Note 16 CONTRACTUAL OBLIGATIONS

(in thousands)

As at March 31, 2020, the AER had contractual obligations totalling $171,894 (2019 - $194,921).

Contractual obligations are obligations of the AER to others that will become liabilities in the future when the terms of those contracts or agreements are met.

As at March 31, 2020, estimated payment requirements for obligations under operating leases and contracts for each of the next five years and thereafter are as follows:

2020-21	$ 43,405
2021-22	23,676
2022-23	18,387
2023-24	14,218
2024-25	11,629
Thereafter	60,579
	$ 171,894

Note 17 ASSETS UNDER ADMINISTRATION

(in thousands)

The AER administers security deposits in accordance with specified acts and regulations. Security deposits are held on behalf of depositors with no power of appropriation and therefore are not reported in these financial statements. The AER does not have any financial risk associated with security collected. Security, along with any interest earned, will be returned to the depositors upon meeting specified refund criteria.

As at March 31, 2020, assets under administration included the following types of security deposits:

	2020	2019	2020	2019
	Cash	Cash	Letters of credit	Letters of credit
Liability Management Rating programs and landfills	$ 98,812	$ 103,518	$ 220,667	$ 223,847
Mine Financial Security program	39,146	35,230	1,434,643	1,426,714
Other programs	6,834	6,958	7,778	7,689
	$ 144,792	$ 145,706	$ 1,663,088	$ 1,658,250

Notes to the Financial Statements

Aberta Energy Regulator
March 31, 2020

Note 18 COMPARATIVE FIGURES

Certain 2019 figures have been reclassified, where necessary, to conform to the 2020 presentation.

Note 19 APPROVAL OF FINANCIAL STATEMENTS

These financial statements were approved by the AER Board of Directors on June 18, 2020.

Expenses Detailed by Object

Aberta Energy Regulator
Year Ended March 31, 2020
Schedule 1

		2020		2019
		(in thousands)		
Salaries, wages and employee benefits	$	192,271	$	179,731
Orphan well abandonment		61,039		45,959
Buildings		20,577		21,219
Computer services		17,238		20,128
Amortization of tangible capital assets		15,947		15,329
Consulting services		12,429		13,715
Administrative		3,492		4,424
Travel and transportation		1,815		3,978
Equipment rent and maintenance		412		753
Loss on disposal and write-down of tangible capital assets		67		119
Abandonment and enforcement		-		55
	$	325,287	$	305,410

Salary and Benefits Disclosure

Aberta Energy Regulator
Year Ended March 31, 2020
Schedule 2

	2020				2019
	Base salary [(a)]	Other cash benefits [(b)]	Other non-cash benefits [(c)]	Total	Total
			(in thousands)		
Position					
Board of Directors					
Chair [(d)]	$ 75	$ -	$ 3	$ 78	$ 168
Members [(e)]	305	-	27	332	369
Executives					
President and Chief Executive Officer	367	134	10	511	183
Former President and Chief Executive Officer [(f)]	-	-	-	-	591
Chief Hearing Commissioner	219	19	58	296	309
Interim Executive Vice-President, Corporate Services [(g,o)]	107	12	38	157	-
Former Executive Vice-President, Corporate Services [(h)]	-	-	-	-	823
Executive Vice-President, Stakeholder & Government Engagement [(i,o)]	155	199	53	407	275
Former Executive Vice-President, Stakeholder & Government Engagement [(j)]	-	-	-	-	737
Executive Vice-President, Strategy & Regulatory [(k,o)]	155	480	51	686	434
Interim Executive Vice-President, Operations [(l,o)]	107	9	32	148	-
Former Executive Vice-President, Operations [(m,o)]	155	199	40	394	384
Executive Vice-President and General Counsel	275	14	74	363	218
Former Executive Vice-President and General Counsel [(n)]	-	-	-	-	358

(a) Includes retainers and per diems for Board Directors and regular salary and acting pay for Executives.

(b) Includes payments in lieu of vacation, pension and health benefits, as well as severance, vehicle allowances and other cash reimbursements. There were no bonuses paid in 2020.

(c) Includes contributions to all benefits as applicable, including employer's share of Employment Insurance, Canada Pension Plan, Government of Alberta and AER pension plans, health benefits, and payments made for professional memberships, tuition fees, fair market value of parking and other taxable benefits.

(d) Two individuals occupied this position during 2020. The current Chair was appointed on September 6, 2019 with remuneration set at $nil. Amounts disclosed are for the former Chair while she occupied the position until September 6, 2019.

(e) Board members are remunerated with monthly honoraria, based on rates prescribed in the Orders in Council. The former Board of Directors consisted of four members until April 28, 2019 and three members from April 28, 2019 until September 6, 2019, at which time their appointments were rescinded. For the remainder of the fiscal year the Board of Directors consisted of four members appointed effective September 6, 2019. Remuneration for one Board member is set at $nil.

(f) The incumbent left the position effective November 30, 2018 and retired effective January 31, 2019. An automobile was provided to the incumbent, but no dollar amount was included in other non-cash benefits for 2019.

(g) Two individuals occupied this position during 2020. The position was vacant from April 1, 2019 to June 24, 2019, at which time the Executive Vice-President, Strategy & Regulatory was appointed Interim Executive Vice-President, Corporate Services and held both positions until October 23, 2019 with no increase in base salary. The position was filled on October 28, 2019. Amounts disclosed are for the current Interim Executive Vice-President, Corporate Services appointed to the position on October 28, 2019.

(h) The incumbent held the position until April 1, 2019, at which time the incumbent was terminated. Severance pay of $334 was expensed in 2019.

(i) The incumbent held the position until October 23, 2019, at which time the incumbent was terminated. Other cash benefits include $168 of severance pay. The Executive Vice-President, Stakeholder & Government Engagement position was eliminated effective October 28, 2019.

(j) On June 1, 2018, the incumbent was appointed to the position of Executive Lead for the International Centre of Regulatory Excellence development project, continuing to report directly to the President and Chief Executive Officer. The incumbent was terminated effective January 31, 2019. Severance pay of $335 was included in other cash benefits for 2019. The 2019 figure has been restated by $5 to include taxable benefits to conform to the 2020 presentation.

(k) On June 24, 2019, the incumbent was appointed Interim Executive Vice-President, Corporate Services and held both this position and that of Executive Vice-President, Strategy & Regulatory until the incumbent was terminated on October 23, 2019. The incumbent did not receive an increase in base salary for holding both positions. Other cash benefits include $449 of severance pay. The Executive Vice-President, Strategy & Regulatory position was eliminated effective October 28, 2019.

(l) The incumbent held the position effective October 28, 2019.

(m) The incumbent held the position until October 23, 2019, at which time the incumbent was terminated. Other cash benefits include $171 of severance pay.

(n) The incumbent left the position effective September 2, 2018, at which time the incumbent was appointed to the position of Executive Counsel, continuing to report directly to the Former President and Chief Executive Officer. The incumbent left the position of Executive Counsel effective January 4, 2019.

Salary and Benefits Disclosure

Aberta Energy Regulator
Year Ended March 31, 2020
Schedule 2 (continued)

(o) Under the terms of the AER's defined benefit SEPP and two supplementary retirement plans (SRP), employees may receive supplemental retirement payments. Retirement arrangement costs as detailed below are not cash payments in the period but are the period expense for rights to future compensation. Costs shown reflect the total estimated cost to provide annual pension income over an actuarially determined post-employment period. The SEPP and SRP provide future pension benefits to participants based on years of service and remuneration. The cost of these benefits is actuarially determined using the projected benefit method pro-rated on service, a market interest rate and management's best estimate of expected costs and the period of benefit coverage. Net actuarial gains and losses of the benefit obligations are amortized over the average remaining service life of the employee group. Current service cost is the actuarial present value of the benefits earned in the fiscal year. Prior service and other costs include amortization of past service costs, amortization of actuarial gains and losses, and interest accruing on the actuarial liability.

SEPP AND SRP RETIREMENT BENEFITS

(in thousands)

The costs detailed below are only for those employees, included in Schedule 2, who were employed during the year ended March 31, 2020 and participated in the SEPP and SRP maintained by the AER. The SEPP and SRP provide retirement benefits to compensate senior staff who do not participate in the government management pension plans.

	2020			2019
Position	**Current service cost**	**Prior service and other costs**	**Total**	**Total**
Interim Executive Vice-President, Corporate Services (g,p)	$ 33	$ -	$ 33	$ 35
Executive Vice-President, Stakeholder & Government Engagement (i,q)	28	-	28	40
Executive Vice-President, Strategy & Regulatory(k,q)	14	1	15	23
Former Executive Vice-President, Operations(m,q)	7	-	7	11

The SEPP and SRP accrued obligation for each executive employed by the AER during the year ended March 31, 2020 is outlined in the following table:

Position	Accrued obligation April 1, 2019	Changes in accrued obligation	Accrued obligation March 31, 2020	Accrued obligation March 31, 2019
Interim Executive Vice-President, Corporate Services (g,p)	$ 85	$ 43	$ 128	$ 85
Executive Vice-President, Stakeholder & Government Engagement (i,q)	40	(24)	16	40
Executive Vice-President, Strategy & Regulatory(k,q)	466	252	718	466
Former Executive Vice-President, Operations(m,q)	55	(55)	-	55

(p) The 2019 figures have been restated as the incumbent was a member of the pension plans prior to his appointment in 2020. The 2020 figures include all amounts for the year ended March 31, 2020.

(q) Includes service to October 23, 2019.

Actual Results Compared with Budget

Aberta Energy Regulator
Year Ended March 31, 2020
Schedule 3

	Budget (Note 4)	Adjustments[a]	Adjusted budget	Actual
		(in thousands)		
Revenues				
Administration fees	$ 232,722	$ -	$ 232,722	$ 233,393
Orphan well abandonment levy and fees	55,813	4,687	60,500	61,039
Information, services and fees	3,542	-	3,542	4,693
Investment income	867	-	867	555
	292,944	4,687	297,631	299,680
Expenses				
Energy regulation	236,331	27,500	263,831	264,248
Orphan well abandonment	55,813	4,687	60,500	61,039
	292,144	32,187	324,331	325,287
	800	(27,500)	(26,700)	(25,607)
Capital				
Capital investment	12,300	-	12,300	12,704
Less: Amortization of tangible capital assets	(11,500)	(4,500)	(16,000)	(15,947)
Loss on disposal and write-down of tangible capital		-		(67)
Net capital investment	800	(4,500)	(3,700)	(3,310)
(Deficit) [b]	$ -	$ (23,000)	$ (23,000)	$ (22,297)

(a) The Adjustments include an increase for severance costs associated with staff reductions to meet multi-year Government of Alberta targets, an increase in orphan well levy required to re-align with the previously approved three-year business plan and an increase in amortization expense related to the implementation of various streams of OneStop technology solutions that support the AER's Integrated Decision Approach.

(b) The AER has been approved by the Government of Alberta to recover the current year deficit over the next two years.

Related Party Transactions

Aberta Energy Regulator
Year Ended March 31, 2020
Schedule 4

The AER, in the normal course of business, entered into various transactions with entities consolidated or accounted for on the modified equity basis in the Government of Alberta's Consolidated Financial Statements. These entities are considered to be related parties of the AER. Related parties also include key management personnel and close family members of those individuals. In 2020, there were no amounts or transactions, other than compensation, between the AER and its key management personnel. Key management personnel compensation is disclosed in Schedule 2.

Related Party Transactions with Government of Alberta Entities

The AER recognized the following transactions with Government of Alberta entities in the Statement of Operations and the Statement of Financial Position at the amount of consideration agreed upon between the related parties:

	Entities in the Ministry of Energy		Other entities	
	2020	2019	2020	2019
	(in thousands)		(in thousands)	
Revenues				
Information, services and fees	$ 96	$ 54	$ 618	$ 1,397

	Entities in the Ministry of Energy		Other entities	
	2020	2019	2020	2019
	(in thousands)		(in thousands)	
Expenses				
Computer services	$ 454	$ 2,050	$ 3,635	$ 2,896
Administrative	-	-	561	714
Buildings	-	-	509	612
Consulting services	-	-	470	625
	$ 454	$ 2,050	$ 5,175	$ 4,847
Receivable from	$ 119	$ 69	$ 4	$ 113
Payable to	$ 94	$ 373	$ 89	$ 2,277
Contractual obligations [(a)]	$ -	$ -	$ 10,390	$ 7,326

(a) Contractual obligations are obligations of the AER to related parties that will become liabilities in the future when the terms of those contracts or agreements are met.

Related Party Transactions

Aberta Energy Regulator
Year Ended March 31, 2020
Schedule 4 (continued)

ICORE Energy Services (NFP)

(in thousands)

The AER was the operating and governing member of a not-for-profit (NFP) corporation, ICORE Energy Services (NFP), from May 17, 2017 to December 19, 2018, when the AER resigned its membership. The AER was a related party with ICORE Energy Services (NFP) from May 17, 2017 to November 30, 2018 as the President and Chief Executive Officer of the AER was also the President and Director of ICORE Energy Services (NFP) during that period.

During this time, the AER incurred in-kind costs for salaries of AER employees and third-party costs for travel and consulting expenses to provide services to ICORE Energy Services (NFP). In 2019, the AER invoiced ICORE Energy Services (NFP) for costs incurred on a cost-recovery basis.

The Statement of Operations for the year ended March 31, 2019 included $3,134 in revenues for amounts invoiced to ICORE Energy Services (NFP) and $1,548 in expenses. These expenses included in-kind costs of $1,103 and third-party costs of $445.

At March 31, 2019, accounts receivable in the Statement of Financial Position included $2,693 due from ICORE Energy Services (NFP), of which $523 was provided for in the allowance for doubtful accounts. In June 2019, the AER received $2,681 from ICORE Energy Services (NFP) for these accounts receivable.

The AER concluded that it did not exercise control over ICORE Energy Services (NFP) as this control was exercised by the Directors and officers of ICORE Energy Services (NFP) in their personal capacity. These individuals directed ICORE Energy Services (NFP) and undertook its activities without the required authorization of the AER, its Board, or the Government of Alberta, in particular the incorporation of ICORE Energy Services (NFP) and causing the AER to become a member of ICORE Energy Services (NFP) in contravention of the Financial Administration Act. As a result, ICORE Energy Services (NFP) financial results were not consolidated into the AER's financial statements for the year ended March 31, 2019. This conclusion is also supported by other facts and relevant guidance under the Public Sector Accounting Standards, including the fact that ICORE Energy Services (NFP) was not carrying out AER operations, functions, or mandate, and that despite temporary reliance on AER resources, ICORE Energy Services (NFP) was intended to operate outside and independently of the AER.

Alberta Utilities Commission

Financial Statements

For the year ended March 31, 2020

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Auditor General OF ALBERTA

Independent Auditor's Report

To the Members of the Alberta Utilities Commission

Report on the Financial Statements

Opinion

I have audited the financial statements of the Alberta Utilities Commission, which comprise the statement of financial position as at March 31, 2020, and the statements of operations, change in net financial assets, and cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In my opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Alberta Utilities Commission as at March 31, 2020, and the results of its operations, its changes in net financial assets, and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Basis for opinion

I conducted my audit in accordance with Canadian generally accepted auditing standards. My responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of my report. I am independent of the Alberta Utilities Commission in accordance with the ethical requirements that are relevant to my audit of the financial statements in Canada, and I have fulfilled my other ethical responsibilities in accordance with these requirements. I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my opinion.

Other information

Management is responsible for the other information. The other information comprises the information included in the *Annual Report*, but does not include the financial statements and my auditor's report thereon. The *Annual Report* is expected to be made available to me after the date of this auditor's report.

My opinion on the financial statements does not cover the other information and I do not express any form of assurance conclusion thereon.

In connection with my audit of the financial statements, my responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or my knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work I will perform on this other information, I conclude that there is a material misstatement of this other information, I am required to communicate the matter to those charged with governance.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with Canadian public sector accounting standards, and for such internal control as management determines is necessary to enable the preparation of the financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Alberta Utilities Commission's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless an intention exists to liquidate or to cease operations, or there is no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Alberta Utilities Commission's financial reporting process.

Auditor's responsibilities for the audit of the financial statements

My objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes my opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, I exercise professional judgment and maintain professional skepticism throughout the audit. I also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for my opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Alberta Utilities Commission's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Alberta Utilities Commission's ability to continue as a going concern. If I conclude that a material uncertainty exists, I am required to draw attention in my auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify my opinion. My conclusions are based on the audit evidence obtained up to the date of my auditor's report. However, future events or conditions may cause the Alberta Utilities Commission to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

I communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that I identify during my audit.

[Original signed by W. Doug Wylie FCPA, FCMA, ICD.D]
Auditor General

May 12, 2020
Edmonton, Alberta

Statement of Operations

Alberta Utilities Commission
Year ended March 31, 2020

	2020 Budget (Schedule 3)	2020 Actual	2019 Actual
	(in thousands)		
Revenues			
Administration fees	$ 31,685	$ 31,291	$ 31,125
Investment income	300	309	310
Professional services and other revenue	100	142	389
	32,085	31,742	31,824
Expenses			
Utility regulation (Schedule 1)	32,885	32,530	32,243
Annual operating deficit	(800)	(788)	(419)
Accumulated surplus, beginning of year	14,059	14,059	14,478
Accumulated surplus, end of year	**$ 13,259**	**$ 13,271**	**$ 14,059**

The accompanying notes and schedules are part of these financial statements.

Statement of Financial Position

Alberta Utilities Commission
As at March 31, 2020

		2020		2019
		(in thousands)		
Financial Assets				
Cash and cash equivalents (Note 5)	$	8,356	$	8,637
Accounts receivable		74		371
Accrued pension asset (Note 6)		585		345
		9,015		9,353
Liabilities				
Accounts payable and accrued liabilities (Note 7)		1,533		1,643
Deferred lease incentive (Note 8)		5,559		6,320
		7,092		7,963
Net Financial Assets		1,923		1,390
Non-Financial Assets				
Capital assets (Note 9)		10,151		11,423
Prepaid expenses		1,197		1,246
		11,348		12,669
Net Assets				
Accumulated surplus (Note 10)	$	13,271	$	14,059

Contractual obligations (Note 11)

The accompanying notes and schedules are part of these financial statements.

Statement of Change in Net Financial Assets

Alberta Utilities Commission
Year Ended March 31, 2020

	2020		2019
	Budget (Schedule 3)	Actual	Actual
	(in thousands)		
Annual operating deficit	$ (800)	$ (788)	$ (419)
Acquisition of capital assets (Note 9)	(1,000)	(729)	(907)
Amortization of capital assets (Note 9)	1,800	1,995	1,933
Net loss (gain) on disposal of capital assets		4	(8)
Proceeds on disposal of capital assets		2	21
Increase in prepaid expenses		49	95
Increase in net financial assets in the year	-	533	715
Net financial assets, beginning of year	1,390	1,390	675
Net financial assets, end of year	**$ 1,390**	**$ 1,923**	**$ 1,390**

The accompanying notes and schedules are part of these financial statements.

Statement of Cash Flows

Alberta Utilities Commission
Year ended March 31, 2020

	2020	2019
	(in thousands)	
Operating transactions		
Annual operating deficit	$ (788)	$ (419)
Non-cash items included in annual deficit:		
Amortization of capital assets (Note 9)	1,995	1,933
Pension expense	662	540
Net loss (gain) on disposal of capital assets	4	(8)
Decrease (increase) in accounts receivable	297	(227)
Decrease in prepaid expenses	49	95
Decrease in accounts payable and accrued liabilities	(94)	(5,738)
Cash provided by (applied to) operating transactions	2,125	(3,824)
Capital transactions		
Acquisition of capital assets (Note 9)	(729)	(907)
Proceeds on disposal of capital assets	2	21
Cash applied to capital transactions	(727)	(886)
Financing transactions		
Pension obligations funded	(902)	(595)
Net lease incentives (amortized) capitalized	(761)	3,315
Net lease obligations repaid	(16)	(18)
Cash (applied to) provided by financing transactions	(1,679)	2,702
Decrease in cash and cash equivalents	(281)	(2,008)
Cash and cash equivalents, beginning of year	8,637	10,645
Cash and cash equivalents, end of year	**$ 8,356**	**$ 8,637**

The accompanying notes and schedules are part of these financial statements.

Notes to the Financial Statements

Alberta Utilities Commission
March 31, 2020
(in thousands of dollars)

Note 1 Authority

The Alberta Utilities Commission (AUC) operates under authority of the *Alberta Utilities Commission Act, Chapter A-37.2* . The AUC also exercises powers and authorities under a number of other statutes. The AUC is an independent, quasi-judicial agency of the government of Alberta that ensures the delivery of Alberta's utility services takes place in a manner that is fair, responsible, and in the public interest. The AUC regulates investor owned electric, natural gas and water utilities, and certain municipally owned electricity utilities to ensure customers receive safe and reliable service at just and reasonable rates. The AUC is responsible for making timely decisions on the need, siting, construction, alteration, operation and decommissioning of natural gas and certain electricity transmission facilities. The AUC also regulates power plants in a similar fashion except the need for new power plants is determined by market forces. The AUC develops and amends rules that support the orderly operation of the retail natural gas and electricity markets, and adjudicates on market and operational rule contraventions that the Market Surveillance Administrator may bring before the AUC. The AUC is exempt from income taxes under the *Income Tax Act* .

Note 2 Summary of significant accounting policies and reporting practices

Basis of financial reporting

These financial statements are prepared in accordance with Canadian Public Sector Accounting Standards (PSAS). Significant accounting policies are as follows:

Revenues
All revenues are reported on the accrual basis of accounting. Cash received for which services have not been provided by year end is recognized as unearned revenue and recorded in accounts payable and accrued liabilities.

Expenses
All expenses are reported on the accrual basis of accounting. The cost of all goods consumed and services received during the year is expensed. Contributed services are not recognized in the Statement of Operations but are disclosed in Note 12 of the financial statements.

Foreign currency translation
Foreign currency transactions are translated at the exchange rate prevailing at the date of transaction. Monetary liabilities denominated in foreign currencies are translated to Canadian dollars at the exchange rate prevailing at fiscal year-end.

Valuation of financial assets and liabilities
The AUC's financial assets and liabilities are generally measured as follows:

Financial Statement Component	Measurement
Cash and cash equivalents	Cost
Accounts receivable	Lower of cost or net recoverable value
Accrued pension asset	Projected benefit method
Accounts payable and accrued liabilities	Cost
Deferred lease incentive	Amortized cost
Capital lease obligation	Lower of cost or present value of minimum lease payments

The AUC does not carry any financial assets or liabilities at fair value and has no derivatives or unsettled exchange gains or losses, therefore the statement of remeasurement gains or losses is not included in these financial statements.

Notes to the Financial Statements

Alberta Utilities Commission
March 31, 2020
(in thousands of dollars)

Note 2 Summary of significant accounting policies and reporting practices (continued)

Financial assets
Financial assets are assets that could be used to discharge existing liabilities or finance future operations and are not for consumption in the normal course of operations.

Financial assets are the AUC's financial claims on external organizations and individuals at the year end.

Cash and cash equivalents
Cash comprises cash on hand and demand deposits.

Accounts receivable
Accounts receivable are recognized at the lower of cost or net recoverable value. A valuation allowance is recorded when recovery is uncertain.

Accrued pension asset
Accrued pension asset represents pension plan contributions made in excess of the pension expense which is actuarially determined using the projected benefit method prorated on length of service and management's best estimate of expected plan investment performance, projected employees' compensation levels, and length of service to the time of retirement.

For the purpose of calculating pension expense, the AUC uses the expected future rate of return on plan assets as its discount rate. For the purpose of calculating the expected return, plan assets are valued at market-related values.

Past service costs arising from plan amendments are expensed in the period of the plan amendment. Any actuarial gain or loss is amortized over the average remaining service period of active employees.

Defined contribution plan accounting is applied to the government of Alberta multi-employer defined benefit pension plans as the AUC has insufficient information to apply defined benefit plan accounting.

Liabilities
Liabilities are present obligations of the AUC to external organizations and individuals arising from past transactions or events occurring before the year end, the settlement of which is expected to result in the future sacrifice of economic benefits. They are recognized when there is an appropriate basis of measurement and management can reasonably estimate the amounts. Generally, liabilities include trade payables, accrued liabilities and accrued employee vacation entitlements.

Deferred lease incentive
Lease incentive benefits are amortized on a straight line basis over the term of lease as a reduction to rental expense.

Capital lease obligation
Capital lease obligation and the corresponding leased capital asset is recorded at the lower of the leased property's fair value and the present value of the minimum lease payments.

Non-financial assets
Non-financial assets are acquired, constructed, or developed assets that do not normally provide resources to discharge existing liabilities, but instead:

(a) are normally employed to deliver AUC services;
(b) may be consumed in the normal course of operations; and
(c) are not for sale in the normal course of operations.

Notes to the Financial Statements

Alberta Utilities Commission
March 31, 2020
(in thousands of dollars)

Note 2 Summary of significant accounting policies and reporting practices (continued)

Non-financial assets include capital assets and prepaid expenses.

Capital assets
Capital assets are recognized at cost, which includes amounts that are directly related to the acquisition, design, construction, development, improvement or betterment of the assets.

The cost, less residual value, of capital assets, are amortized on a straight-line basis over its estimated useful life as follows:

Computer hardware and software	Four to seven years
Furniture and equipment	Four to forty years
Leasehold improvements	Lease term

Capital assets are written down when conditions indicate that they no longer contribute to the AUC's ability to provide services, or when the value of future economic benefits associated with the capital assets are less than their net book value. The net write-downs are accounted for as expenses in the Statement of Operations.

The capitalization threshold for all capital assets is $1.5 unless they are included in certain capital asset pools.

Prepaid expenses
Prepaid expenses are recorded at cost and amortized based on the terms of the agreement.

Measurement uncertainty
Measurement uncertainty exists when there is a variance between the recognized or disclosed amount and another reasonably possible amount. The amounts recorded for amortization of capital assets are based on estimates of the useful life of the related assets. Also, the accrued pension asset incorporates multiple assumptions. Actual results for amortization and accrued pension asset may differ from reported values.

Note 3 Future accounting changes

The Public Sector Accounting Board has approved the following accounting standards:

PS 3280 Asset Retirement Obligations (effective April 1, 2021)
This standard provides guidance on how to account for and report liabilities for retirement of tangible capital assets. Management is currently assessing the impact of this standard on the financial statements.

PS 3400 Revenue (effective April 1, 2022)
This standard segregates revenue into exchange and non-exchange transactions. Revenue for exchange transactions is recognized when each performance obligation is satisfied. Non-exchange transactions do not contain performance obligations. Management has performed a review of PS 3400 Revenue and does not anticipate a change from its current revenue recognition policy.

Notes to the Financial Statements

Alberta Utilities Commission
March 31, 2020
(in thousands of dollars)

Note 4 Financial instruments

The AUC has the following financial instruments: accounts receivable, accounts payable and accrued liabilities.

The AUC has exposure to the following risks from its use of financial instruments:

Liquidity risk
Liquidity risk is the risk that the AUC will encounter difficulty in meeting obligations associated with financial liabilities. The AUC does not consider this to be a significant risk as it collects the majority of annual revenues at the beginning of the year and maintains a significant cash reserve to meet all obligations that arise during the year.

Credit risk
The AUC is not exposed to any significant credit risk from potential non-payment of accounts receivable. As at March 31, 2020, the balance of accounts receivables does not contain amounts that were past due or uncollectible.

Note 5 Cash and cash equivalents

Cash and cash equivalents consist of deposits in the Consolidated Cash Investment Trust Fund which is managed by the Province of Alberta to provide interest income at competitive rates while maintaining appropriate security and liquidity of depositors' capital. The Fund is comprised of high quality short-term and mid-term fixed income securities with a maximum term to maturity of three years. As at March 31, 2020, securities held by the Fund have a time-weighted return of 1.9 per cent per annum (2019: 1.8 per cent).

Note 6 Pension

The AUC participates in the Government of Alberta's multi-employer pension plans of Management Employees Pension Plan, Public Service Pension Plan, and Supplementary Retirement Plan for Public Service Managers. The expense for these pension plans is equal to the contribution of $2,078 for the year ended March 31, 2020 (2019: $1,810). The AUC is not responsible for future funding of the plans deficit other than through contribution increases.

In addition, the AUC maintains its own defined benefit Senior Employees Pension Plan (SEPP) and two supplementary pension plans to compensate senior staff who do not participate in the government management pension plans. Retirement benefits are based on each employee's years of service and remuneration.

The effective date of the most recent actuarial funding valuation for SEPP was December 31, 2018. The accrued benefit obligation as at March 31, 2020 is based on the extrapolation of the results of this valuation. The effective date of the next required funding valuation for SEPP is December 31, 2021.

Pension plan assets are valued at market values. During the year ended March 31, 2020 the weighted average actual return on plan assets was 1.47 per cent (2019: 6.55 per cent).

Significant weighted average actuarial and economic assumptions used to value accrued benefit obligations and pension benefit costs are as follows:

	March 31, 2020	March 31, 2019
Accrued benefit obligations		
Discount rate	4.26%	4.71%
Rate of compensation increase	3.50%	3.50%
Long-term inflation rate	2.00%	2.00%

Notes to the Financial Statements

Alberta Utilities Commission
March 31, 2020
(in thousands of dollars)

Note 6 Pension (continued)

	2020	2019
Pension Benefit costs for the year		
Discount rate	4.71%	4.70%
Expected rate of return on plan assets	4.71%	4.70%
Rate of compensation increase	3.50%	3.50%

The funded status and amounts recognized in the Statement of Financial Position are as follows:

	March 31, 2020	March 31, 2019
Market value of plan assets	$ 13,306	$ 12,414
Accrued benefit obligations	14,514	11,276
Plan (deficit) surplus	(1,208)	1,138
Unamortized actuarial loss (gain)	1,793	(793)
Accrued pension asset	$ 585	$ 345

The pension benefit costs for the year include the following components:

	2020	2019
Current period benefit costs	$ 643	$ 556
Interest cost	591	484
Expected return on plan assets	(610)	(526)
Amortization of actuarial losses	38	26
	$ 662	$ 540

The average remaining service period of active employees is 6.6 years (2019: 6.6 years).

Additional information about the defined benefit pension plans is as follows:

	2020	2019
AUC contribution	$ 902	$ 595
Employees' contribution	192	107
Benefits paid	390	168

The asset allocation of the defined benefit pension plans' investments is as follows:

	March 31, 2020	March 31, 2019
Equity securities	43.40%	47.40%
Debt securities	17.59%	17.40%
Other	39.01%	35.20%
	100.00%	100.00%

Notes to the Financial Statements

Alberta Utilities Commission
March 31, 2020
(in thousands of dollars)

Note 7 Accounts payable and accrued liabilities

	2020	2019
Accounts payable	$ 220	$ 425
Accrued liabilities	1,259	1,148
Capital lease obligation	54	70
	$ 1,533	$ 1,643

Note 8 Deferred lease incentive

The AUC has received lease incentives through its office lease agreements. During 2020, the AUC received $0 in lease incentives in the form of cash and free rent (2019: $4,019).

	2020	2019
Opening balance	$ 6,320	$ 3,005
Cash incentive received	-	2,754
Rent free period received	-	1,265
Lease incentive amortized	(761)	(704)
Closing balance	$ 5,559	$ 6,320

Note 9 Capital assets

	March 31, 2020				March 31, 2019
	Furniture and equipment	Computer hardware and software	Leasehold improvement	Total	Total
Historical cost					
Beginning of year	$ 3,109	$ 9,203	$ 6,325	$ 18,637	$ 20,889
Additions	1	723	5	729	907
Disposals	(17)	(585)	-	(602)	(3,159)
	$ 3,093	$ 9,341	$ 6,330	$ 18,764	$ 18,637
Accumulated amortization					
Beginning of year	$ 664	$ 5,610	$ 940	$ 7,214	$ 8,427
Amortization expense	333	965	697	1,995	1,933
Effect of disposals	(15)	(581)	-	(596)	(3,146)
	$ 982	$ 5,994	$ 1,637	$ 8,613	$ 7,214
Net book value at March 31, 2020	**$ 2,111**	**$ 3,347**	**$ 4,693**	**$ 10,151**	**$ 11,423**
Net book value at March 31, 2019	**$ 2,445**	**$ 3,593**	**$ 5,385**	**$ 11,423**	

Notes to the Financial Statements

Alberta Utilities Commission
March 31, 2020
(in thousands of dollars)

Note 10 Accumulated surplus

Accumulated surplus is comprised of the following:

	2020			2019
	Investments in capital assets	Unrestricted surplus	Total	Total
Opening balance	$ 11,423	$ 2,636	$ 14,059	$ 14,478
Annual operating deficit	-	(788)	(788)	(419)
Net investment in capital assets	(1,272)	1,272	-	-
Closing balance	$ 10,151	$ 3,120	$ 13,271	$ 14,059

Note 11 Contractual obligations

Contractual obligations are obligations of the AUC to others that will become liabilities in the future when the terms of those contracts or agreements are met. Contractual obligations for each of the next five years and thereafter are as follows:

Obligations under operating leases, service contracts and maintenance agreements

	Total
2021	$ 3,919
2022	2,882
2023	2,444
2024	2,526
2025	2,397
Thereafter	7,129
	$ 21,297

Note 12 Related party transactions

Related parties are those entities consolidated or accounted for on the modified equity basis in the Government of Alberta's Consolidated Financial Statements. For the year ended March 31, 2020 the AUC received and paid $196 (2019: $169) for services from other government of Alberta organizations. The AUC had not received or provided any contributed goods or services from other government of Alberta organizations. Related parties also include key management personnel and close family members of those individuals at the AUC. There were no transactions between the AUC and its key management personnel or close family members during the year.

Note 13 Approval of financial statements

These financial statements were approved by the AUC's Chair's Management Committee.

Expenses - Detailed by Object

Alberta Utilities Commission
Year Ended March 31, 2020
Schedule 1

	2020		2019
	Budget	Actual	Actual
	(in thousands)		
Salaries, wages and employee benefits	$ 24,645	$ 25,028	$ 24,390
Supplies and services	6,440	5,503	5,920
Amortization of capital assets (Note 9)	1,800	1,995	1,933
Loss on disposal of capital assets	-	4	-
	$ 32,885	$ 32,530	$ 32,243

Salary and Benefits Disclosure

Alberta Utilities Commission
Year Ended March 31, 2020
Schedule 2

	2020				2019
	Base Salary (1)	Other Cash Benefits (2)	Other Non-cash Benefits (3)	Total	Total
	(in thousands)				
Chair of the Commission (4)	$ 333	$ 99	$ 26	$ 458	$ 378
Vice-Chair	219	47	62	328	311
Vice-Chair (5)	143	52	12	207	-
Commission Member	197	35	58	290	270
Commission Member	194	30	58	282	260
Commission Member	197	18	56	271	266
Commission Member	197	15	56	268	271
Commission Member	197	13	42	252	254
Commission Member (6)	68	10	5	83	238
Commission Member (7)	3	2	-	5	81

(1) Includes pensionable base pay.

(2) Includes payments in lieu of vacation, health and pension benefits. No bonuses have been paid.

(3) Employer's contributions to all employee benefits including Employment Insurance, Canada Pension Plan, Alberta pension plans, health benefits, professional memberships, tuition fees and fair market value of parking. Automobiles were provided but no dollar amount included in other non-cash benefits.

(4) Vice-Chair was acting as Chair from May 1, 2018 to July 22, 2018.

(5) The Vice-Chair was appointed on August 5, 2019.

(6) The position was replaced by Vice-Chair position as of August 5, 2019.

(7) The position was vacant from July 23, 2018 to March 24, 2020.

Authorized Budget

Alberta Utilities Commission
Year Ended March 31, 2020
Schedule 3

	Budget (Estimate)	Authorized Changes	Authorized Budget	Actual
	(in thousands)			
Revenues				
Administration fees	$ 31,685	$ -	$ 31,685	$ 31,291
Investment income	300	-	300	309
Professional services	100	-	100	142
	32,085	-	32,085	31,742
Expenses				
Utility regulation	32,885	(300)	32,585	32,530
Net Capital Investment				
Capital investment	1,000	-	1,000	729
Less:				
Amortization	(1,800)	-	(1,800)	(1,995)
Loss on disposal of capital assets	-	-	-	(4)
Proceeds on disposal of capital assets	-	-	-	(2)
	(800)	-	(800)	(1,272)
	$ -	$ 300	$ 300	$ 484

Note:

The Budget is based on the AUC Business Plan for the year ended March 31, 2020. The Budget and Authorized Changes have been approved by the government of Alberta.

Alberta Petroleum Marketing Commission

Financial Statements

For the year ended December 31, 2019

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Auditor General OF ALBERTA

Independent Auditor's Report

To the Board of Directors of the Alberta Petroleum Marketing Commission

Report on the Financial Statements

Opinion

I have audited the financial statements of the Alberta Petroleum Marketing Commission, which comprise the statement of financial position as at December 31, 2019, and the statements of income (loss) and comprehensive income (loss), changes in equity and cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In my opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Alberta Petroleum Marketing Commission as at December 31, 2019, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

Basis for opinion

I conducted my audit in accordance with Canadian generally accepted auditing standards. My responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of my report. I am independent of the Alberta Petroleum Marketing Commission in accordance with the ethical requirements that are relevant to my audit of the financial statements in Canada, and I have fulfilled my other ethical responsibilities in accordance with these requirements. I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my opinion.

Other information

Management is responsible for the other information. The other information comprises the information included in the *Annual Report*, but does not include the financial statements and my auditor's report thereon. The *Annual Report* is expected to be made available to me after the date of this auditor's report.

My opinion on the financial statements does not cover the other information and I do not express any form of assurance conclusion thereon.

In connection with my audit of the financial statements, my responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or my knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work I will perform on this other information, I conclude that there is a material misstatement of this other information, I am required to communicate the matter to those charged with governance.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of the financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Alberta Petroleum Marketing Commission's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless an intention exists to liquidate or to cease operations, or there is no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Alberta Petroleum Marketing Commission's financial reporting process.

Auditor's responsibilities for the audit of the financial statements

My objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes my opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, I exercise professional judgment and maintain professional skepticism throughout the audit. I also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for my opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Alberta Petroleum Marketing Commission's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Alberta Petroleum Marketing Commission 's ability to continue as a going concern. If I conclude that a material uncertainty exists, I am required to draw attention in my auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify my opinion. My conclusions are based on the audit evidence obtained up to the date of my auditor's report. However, future events or conditions may cause the Alberta Petroleum Marketing Commission to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

I communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that I identify during my audit.

[Original signed by W. Doug Wylie FCPA, FCMA, ICD.D]
Auditor General

July 13, 2020
Edmonton, Alberta

Statement of Financial Position

Alberta Petroleum Marketing Commission
As at December 31, 2019
(thousands of Canadian dollars)

	2019	2018
Assets		
Cash and cash equivalents (Note 5)	$ 13,415	$ 5,725
Accounts receivable (Note 6)	83,996	7,243
Intangible assets under development (Note 7)	-	9,818
Intangible assets (Note 8)	10,112	-
Term loan (Note 9)	438,638	438,638
Accrued interest on Term loan (Note 9)	213,571	152,044
Total assets	$ 759,732	$ 613,468
Liabilities		
Accounts payable (Note 10)	$ 36,184	$ 38,705
Due to the Department of Energy (Note 11)	84,586	2,707
Short term debt (Note 12)	831,850	625,228
Accrued interest on Short term debt	31,108	16,303
Sturgeon refinery Processing Agreement provision (Note 13)	1,727,000	-
Total liabilities	2,710,728	682,943
Total equity	(1,950,996)	(69,475)
Total liabilities and equity	$ 759,732	$ 613,468

Commitments (Note 15)

The accompanying notes are an integral part of these financial statements.

Statement of Income (Loss) and Comprehensive Income (Loss)

Alberta Petroleum Marketing Commission
For the year ended December 31, 2019
(thousands of Canadian dollars)

	2019	2018
Conventional crude oil marketing operations		
Marketing fee revenue (Note 16)	$ 6,747	$ 5,717
Finance income	138	134
	6,885	5,851
Expense		
Wages & benefits (Note 16)	4,041	3,529
Consulting	1,579	792
Software & maintenance (Note 16)	581	122
Amortization expense for intangible assets (Note 8)	532	-
Dues & subscriptions	173	131
Directors' fees	96	49
Change to loss provision re: Accounts receivable	67	(49)
Travel	49	30
Other	36	24
	7,153	4,628
Net (loss) income from conventional crude oil marketing operations	(268)	1,223
Sturgeon Refinery		
Finance income	61,588	53,359
Sturgeon refinery Processing Agreement provision (Note 13)	(1,727,000)	-
Debt tolls expense (Note 17)	(200,935)	(209,601)
Finance costs	(14,805)	(8,286)
Trust costs	(76)	(63)
Change to loss provision re: Term loan & Accrued interest	(25)	157
Net (loss) attributable to Sturgeon Refinery	(1,881,253)	(164,434)
Net (loss) and comprehensive (loss)	$ (1,881,521)	$ (163,211)

The accompanying notes are an integral part of these financial statements.

Statement of Changes in Equity

Alberta Petroleum Marketing Commission
For the year ended December 31, 2019
(thousands of Canadian dollars)

	2019	2018
Equity, beginning of year	$ (69,475)	$ 94,331
Credit loss provision per IFRS 9 (Note 3(b))	-	(595)
Net (loss) and comprehensive (loss)	(1,881,521)	(163,211)
Equity, end of year	$ (1,950,996)	$ (69,475)

The accompanying notes are an integral part of these financial statements.

Statement of Cash Flows

Alberta Petroleum Marketing Commission
For the year ended December 31, 2019
(thousands of Canadian dollars)

	2019	2018
Operating activities		
Net (loss) and comprehensive (loss)	$ (1,881,521)	$ (163,211)
Non-cash items included in net income (loss)		
Accrued interest on term loan	(61,552)	(53,359)
Accrued interest on short term debt	14,805	8,286
Amortization of intangible assets	532	-
Change to loss provision re: Accounts receivable	67	(49)
Change to loss provision re: Term loan & Accrued interest	25	(157)
Sturgeon refinery Processing Agreement provision	1,727,000	-
Changes in non-cash working capital		
(Increase)/ decrease in accounts receivable	(76,820)	83,888
(Decrease)/ Increase in accounts payable	(2,521)	16,843
Increase/ (decrease) in due to Department of Energy	81,879	(78,411)
Net cash from operating activities	(198,106)	(186,170)
Investing activities		
Term loan	-	(46,850)
Intangible assets under development	(826)	(1,693)
Net cash used in investing activities	(826)	(48,543)
Financing activities		
Proceeds from issuance of short term debt	206,622	233,265
Net cash from financing activities	206,622	233,265
Increase/ (decrease) in cash and cash equivalents	7,690	(1,448)
Cash and cash equivalents, beginning of year	5,725	7,173
Cash and cash equivalents, end of year	$ 13,415	$ 5,725

The accompanying notes are an integral part of these financial statements.

Notes to the Financial Statements

Alberta Petroleum Marketing Commission
(in thousands of Canadian dollars unless otherwise noted)

Note 1 Authority and structure

The Alberta Petroleum Marketing Commission ("APMC" or the "Commission") operates under the authority of the *Petroleum Marketing Act, Chapter P-10*, Revised Statutes of Alberta 2000, and the *Natural Gas Marketing Act*, Chapter N-1, Revised Statutes of Alberta 2000. Pursuant to Alberta legislation the Commission as agent of Her Majesty the Queen in right of Alberta (the "Province"), as represented by the Department of Energy (the "Department"), accepts delivery of and markets the Province's royalty share of crude oil. This is achieved through the Commission receiving crude oil in kind from producers on behalf of the Department and transferring the proceeds received from the sale of the crude oil back to the Department. These financial statements disclose the transactions the Commission incurs while acting as agent on behalf of the Department.

The *Petroleum Marketing Act* was amended on January 10, 2014. The amendments provided the Minister of Energy with new power to give directions to APMC; modernized and improved the basic corporate rules under which APMC operates including the ability to appoint up to seven directors, some of whom may be from outside the public service; clarified financial tools available to APMC and ensured proper Crown controls on use of these tools.

The Commission's mandate has been enhanced to include assisting in the development of new energy markets and transportation infrastructure. In line with that is the Commission's involvement with North West Redwater Partnership ("NWRP") and the Sturgeon Refinery. The Commission operates a Business Development group to identify and analyze business ideas and proposals that provide strategic value to Alberta and are financially feasible.

As an agent of the Government of Alberta, the Commission is not subject to federal or provincial corporate income taxes.

The Commission is located at the following address: #300, 801 – 6th Avenue S.W., Calgary, Alberta, T2P 3W2. These financial statements were authorized for issue by the Board of Directors on July 13, 2020.

Note 2 Basis of preparation

(a) Basis of presentation

These financial statements have been prepared in compliance with International Financial Reporting Standards (IFRS) as published by the International Accounting Standards Board (IASB).

(b) Basis of measurement

The financial statements have been prepared under the historical cost convention, except as disclosed in the significant accounting policies in Note 3.

(c) Financial and presentation currency

These financial statements are presented in Canadian dollars, which is the Commission's functional currency.

Note 3 Significant accounting policies

The precise determination of many assets and liabilities is dependent upon future events. Accordingly, the preparation of financial statements for a reporting period necessarily involves the use of estimates and approximations that have been made using careful judgment. Actual results could differ from those estimates. These financial statements have been prepared within reasonable limits of materiality and within the framework of the accounting policies summarized below.

Notes to the Financial Statements

Alberta Petroleum Marketing Commission
(in thousands of Canadian dollars unless otherwise noted)

(a) Revenue from contracts with customers

The Commission adopted IFRS 15 on January 1, 2018 using the retrospective with cumulative effect method. There were no changes to reported net income (loss) and comprehensive income (loss) or equity as a result of adopting IFRS 15.

Upon adoption of IFRS 15, the Commission applied the practical expedient such that contracts that were completed in the comparative periods have not been restated. Applying this expedient had no impact to the revenue recognized under the previous revenue accounting standard as all performance obligations had been met and the consideration had been determined.

Effective January 1, 2018, the Commission's accounting policy for Revenue is as follows: The Commission earns revenue through marketing fees charged to the Department of Energy based on net volumes sold. Marketing fees are recognized when earned which corresponds to the service period in which the conventional crude oil marketing activities take place.

As part of the marketing activities, inventory of $1,152 is being held in a fiduciary capacity on behalf of the Department at December 31, 2019 ($229 as at December 31, 2018). Inventory represents the royalty oil in feeder and trunk pipelines and consists of both purchased oil and royalty share oil. The Commission purchases oil to fulfill pipeline and quality requirements as part of the conventional crude oil marketing activities. As the Commission does not hold title to the oil and will not benefit from the ultimate sale as a principal, inventory is not recognized.

The Commission will adopt IFRS 15 in its accounting for the Sturgeon Refinery when it achieves the Commercial Operations Date (COD) in 2020.

(b) Financial instruments

IFRS 9 – Financial Instruments is effective for years beginning on or after January 1, 2018. Effective January 1, 2018 the Commission has retrospectively adopted IFRS 9 in accordance with the allowed transitional provisions. An impairment provision was calculated for its financial assets as at December 31, 2017 and this amount was reflected in the 2018 opening net assets. No restatement has been made in the comparative periods for this initial impairment provision.

From January 1, 2018, the Commission classifies its financial assets in the following categories: measured at amortized cost, fair value through other comprehensive income and fair value through profit or loss. The classification is made at initial recognition and depends on the Commission's business model for managing financial assets and the contractual terms of the cash flows. Subsequent measurement of financial instruments is based on their initial classifications. The Commission classifies cash and short term investments, accounts receivable, term loan and accrued interest on term loan as financial assets at amortized cost, and accounts payable, due to department of energy, short term debt, and accrued interest on short term debt as financial liabilities at amortized cost.

Amortized cost is defined as the amount at which the financial asset or financial liability is measured at initial recognition minus the principal repayments, plus or minus the cumulative amortization using the effective interest method of any difference between the initial amount and the maturity amount and, for financial assets, as adjusted for any loss allowance.

Effective January 1, 2018 the Commission's accounting policy for impairment of financial assets is as follows: At each reporting date, on a forward looking basis, the Commission assesses the expected losses associated with its financial assets carried at amortized cost. For trade accounts receivable, the simplified approach permitted by IFRS 9 is applied, which requires expected lifetime credit losses to be recognized from initial recognition of the receivable. To measure expected credit losses, accounts receivable are grouped based on the counterparty investment rating and applying an anticipated default rate, as reported by the credit rating agencies, to each rating multiplied by the receivable balance outstanding at a reporting date. For counterparties

Notes to the Financial Statements

Alberta Petroleum Marketing Commission
(in thousands of Canadian dollars unless otherwise noted)

not rated by the credit rating agencies, the simplified approach and a provision matrix will be used to calculate the impairment provision. The matrix would look at a different percentage applied against each aging category, including the current amounts. The internal and external credit rating of a counterparty will be considered as part of this overall process.

For the NWRP term loan and accrued interest, we measure expected credit losses using the default rates for the Government of Alberta and Canadian Natural Resources Limited (CNRL) weighted credit ratings.

Changes in the provision for expected credit loss are recognized on the statement of income (loss) and comprehensive income (loss).

The initial impairment provision calculated effective January 1, 2018 was $595 and reflected as a deduction to net assets (liabilities). The increase in the impairment provision for the year ended December 31, 2019 is $92 (for the year ended December 31, 2018 was a decrease of $206) recorded through the statement of income (loss) and comprehensive income (loss).

(c) Foreign currency

Transactions in foreign currencies are translated to the appropriate functional currency at foreign exchange rates that approximate those on the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the appropriate functional currency at foreign exchange rates at the financial statement date. Foreign exchange differences arising on translation are recognized in income. Non-monetary assets that are measured in a foreign currency at historical cost are translated using the exchange rate at the date of the transaction.

(d) Impairment of loans and receivables

Loans and receivables are assessed at each reporting date to determine whether there is any objective evidence of impairment. A loan or receivable is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset. An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics. All impairment losses are recognized in income in the period incurred. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost, the reversal is recognized in the statement of income (loss) and comprehensive income (loss). The reversal amount would not be more than the asset's carrying amount.

(e) Finance income

Finance income generated from conventional crude oil marketing operations comprises interest income earned on short term investments. Finance income related to the Sturgeon Refinery is earned on a term loan at prime plus six percent compounded monthly.

(f) Provisions

Provisions are recognized when the Commission has a present legal or constructive obligation as a result of past events, it is probable that an outflow of resources will be required to settle the obligation, and the amount has been reliably estimated. Provisions are not recognized for future operating losses. Provisions are measured at the present value of the expenditures expected to be required to settle the obligation using a rate that reflects current market assessments of the time value of money and the risks specific to the obligation. The increase in the provision due to passage of time is recognized as interest expense.

Notes to the Financial Statements

Alberta Petroleum Marketing Commission
(in thousands of Canadian dollars unless otherwise noted)

At each year-end APMC performs an onerous contract assessment. A provision for an onerous contract is recorded when the unavoidable costs of meeting an obligation under a contract exceed the economic benefits expected to be received under it. This provision would be recorded as an expense on the statement of income (loss) and comprehensive income (loss) and offsetting liability on the statement of financial position. For each subsequent year-end the Commission will perform an assessment to determine the updated net present value. The balance sheet provision will be adjusted each year to the new net present value (either higher or lower) with the offset being recorded through the income statement. If the net present value turns positive then the reversal of the provision on the balance sheet is to zero (i.e. the contract cannot become an asset).

(g) Intangible assets

The Commission has internally developed operations software to handle actualization and settlement of royalty and marketing transactions. In addition, APMC purchased accounting software for reporting and financial settlement of transactions. The development of the systems occurred over a number of years and the costs have been capitalized under Intangible assets under development. Eligible costs include: billings from Service Alberta and previously the Department's Information Management Technical Services (IMTS) group for development; directly attributable costs; consulting and wages and benefits of people working on the project. Both systems became operational in July 2019. In July 2019, these costs were transferred from Intangible assets under development to Intangible assets.

The Intangible assets are amortized on a straight-line basis over the estimated useful life of the software. The software systems have an estimated useful life of 10 years.

(h) Impairment of intangible assets

Intangible assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable. In addition, an annual review is performed. Assets are grouped at the lowest level where there are separately identifiable cash inflows for the purpose of assessing impairment.

If there is an indication of impairment, the asset's recoverable amount is estimated. The recoverable amount is the greater of an asset's fair value less cost to sell and its value in use, if the carrying amount of the asset exceeds the recoverable amount, an impairment loss is recognized. Impairment losses are recognized in the statement of income (loss) and comprehensive income (loss).

If the circumstances leading to the impairment are no longer present, an impairment loss may be reversed. The extent of the impairment loss that can be reversed is determined by the carrying cost net of amortization that would have existed if the impairment had not occurred. Therefore, reversal of the loss cannot exceed the total carrying cost less amortization of the asset had the impairment not occurred. The impairment loss reversals are recognized in the statement of income (loss) and comprehensive income (loss).

The Commission has completed its review of Intangible assets and determined there is no impairment.

Note 4 Critical accounting estimates and judgments

(a) Government business enterprise

Under public sector accounting standards, organizations which are controlled by the government are either government business enterprises or other government organizations. Government business enterprises are required to apply IFRS, whereas other government organizations are provided with a choice for basis of presentation. The Commission has exercised judgment and determined that it is a government business enterprise because it is a separate legal entity and has been delegated financial and operational authority to carry on a business. In 2013, the Commission's mandate was expanded, and it is expected through its involvement with other marketing activities, such as the Sturgeon Refinery that it can provide services, maintain its operations and meet liabilities from sources outside of the government reporting entity. Had the Commission

Notes to the Financial Statements

Alberta Petroleum Marketing Commission
(in thousands of Canadian dollars unless otherwise noted)

not been determined to be a government business enterprise, the Commission would have continued to apply public sector accounting standards, and such an alternative basis of accounting could have a pervasive effect on the measurement and presentation of items in the financial statements.

(b) Revenue recognition

The Commission has exercised judgment in determining whether it is acting as a principal or agent with respect to conventional crude oil marketing activities. The Commission is providing services to the Crown as delegated in the *Petroleum Marketing Act* that are *"…in the public interest of Alberta"*. The Commission accepts delivery of and markets the Crown's royalty share of crude oil, and has the ability to determine which customers to transact with, and whether it should purchase additional product for blending activities to change the composition of crude oil sold. The Crown has delegated, through the *Petroleum Marketing Act* the responsibilities to the Commission for ensuring the crude oil meets the customers' specifications and establishing prices of the crude oil. However, the Commission is not exposed to inventory risk, this risk belongs to the Crown. Therefore, the gross inflows and economic benefits of conventional crude oil marketing activities are considered collected on behalf of the Department and are not recognized as revenue.

Had the Commission been considered to be a principal the Statement of Income (loss) and Comprehensive Income (loss) would have included: $951,732 revenues; $80,954 expenses; and $870,778 royalties to be transferred to the Department respectively ($1,113,495 revenues, $70,857 expenses and $1,042,638 royalties to be delivered to the Department – 2018).

APMC has used judgment in determining whether it is acting as a principal or agent with respect to crude-by-rail activities. APMC was directed, on May 24, 2019, "…take all steps possible to explore best options for assigning crude-by-rail program contracts entered into by the Commission to third parties, and to enter into assignment agreements as expeditiously as possible with third parties on commercial terms, provided that the final terms have been approved by the Government". While the Commission entered into the contracts, it was acting as agent on behalf of the Crown and all financial risk belongs to the Crown. Therefore, the gross inflows and economic benefits of the crude-by-rail program are considered collected on behalf of the Crown and are not recognized as revenue.

(c) NWRP – Significant influence

The Commission has exercised judgment in determining APMC has significant influence over NWRP. However, the Commission has no equity ownership interest in NWRP. APMC will not equity account for NWRP within the accounts of the Commission's financial statements, however, will provide summarized NWRP financial information in these notes. See Note 9 for further details

NWRP is a general partnership formed by CNR (Redwater) Limited (formerly Canadian Natural Upgrading Limited), a wholly-owned subsidiary of Canadian Natural Resources Limited and by NWU LP, an indirect wholly-owned subsidiary of North West Refining Inc. NWRP was formed under the *Partnership Act (Alberta)* pursuant to a partnership agreement dated February 15, 2011, as amended on November 7, 2012, March 11, 2013 and April 7, 2014. The partners each have a 50% partnership interest in NWRP.

NWRP has entered into various agreements to construct and operate a refinery 45 kilometres north-east of Edmonton to have the capacity to process approximately 50,000 barrels per day (bbl/d) of bitumen at an incurred facility capital cost (FCC) of $10.1 billion ($10.0 billion as at December 31, 2018). Design and construction deficiencies, scope changes, productivity challenges during construction and a higher than expected USD/CAD exchange rate have resulted in upward budgetary pressures. APMC will provide the Sturgeon Refinery with 37,500 bbl/d of bitumen feedstock and Canadian Natural Resources Partnership will provide the remaining 12,500 bbl/d of bitumen feedstock under two 30 year fee-for-service tolling agreements. NWRP targets the refinery to come on stream to process bitumen feedstock and achieve COD in 2020.

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APMC has entered into a term loan with NWRP which earns interest at a rate of prime plus six percent, compounded monthly, and will be repaid over 10 years starting one year after commercial start-up. While the loan to NWRP is outstanding, APMC is entitled to a 25 percent voting interest on an Executive Leadership Committee, which is charged with overseeing and making decisions on the construction, start-up and operation of the Sturgeon Refinery.

In 2019 APMC did not lend any additional monies ($46,850 - 2018) to NWRP (total as at December 31, 2019 $438,813) in the form of term loans.

(d) NWRP - Monthly toll commitment

The Commission has used judgment to estimate the toll commitments included in Note 15 Commitments. The components of the toll are: senior debt; operating costs; class A subordinated debt; equity; and incentive fees. To calculate the toll, management has used estimates for factors including future interest rates, operating costs, oil prices (WTI and light/heavy differentials), refined product prices, gas prices and foreign exchange rates.

(e) NWRP - Processing agreement assessment

The Commission uses a cash flow model to determine if the unavoidable costs of meeting the obligations under the NWRP Processing Agreement exceed the economic benefits expected to be received. The model uses a number of variables to calculate a discounted net cash flow for APMC. Those variables include technical variables that arise from the design of the project such as pricing related variables including crude oil prices (WTI), heavy-light differentials, ultra-low sulphur diesel-WTI premiums, exchange rates, capital costs, operating costs, interest rates, discount rates; and operating performance compared to capacity.

Technical inputs may be estimated with reasonable accuracy for a particular operating plan; however revenues and costs that depend upon market prices are challenging to estimate, particularly over long future time periods. The Processing Agreement has a term of 30 years and may be renewed for successive five year periods at APMC's option. In order to perform the onerous contract analysis, APMC management developed estimates for the key variables based primarily on Government of Alberta forecasts.

Based on the analysis, as at the authorization date of these financial statements, APMC determined the agreement has a negative net present value and a provision is required. See Note 13 for further details.

For each subsequent year-end the Commission will perform this Processing agreement assessment to determine the updated net present value. The balance sheet provision will be adjusted each year to the new net present value (either higher or lower) with the offset being recorded through the income statement. If the net present value turns positive then the reversal of the provision on the balance sheet is to zero (i.e. the contract cannot become an asset).

Note 5 Cash and cash equivalents

	December 31, 2019	December 31, 2018
Cash and cash equivalents	$ 13,415	$ 5,230
Cash, Initial Proceeds Trust Account	-	495
	$ 13,415	$ 5,725

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Cash and cash equivalents consist of deposits in the Consolidated Cash Investment Trust Fund (the "Fund") which is managed by Alberta Investment Management Corporation to provide competitive interest income while maintaining appropriate security and liquidity of depositors' capital. The Fund is comprised of high quality short-term and mid-term fixed income securities with a maximum term to maturity of three years. For the year ended December 31, 2019, APMC earned a rate of return of 1.82% per annum (1.66% per annum – 2018). Due to the nature of Fund investments, the carrying value approximates fair value.

The Initial Proceeds Trust Account are monies held by Computershare (a trustee on behalf of the Sturgeon Refinery Toll payers – APMC and CNRL).

Note 6 Accounts Receivable

	December 31, 2019	December 31, 2018
Accounts receivable	$ 84,216	$ 7,396
Credit loss provision per IFRS 9	(220)	(153)
Balance, end of year	$ 83,996	$ 7,243

Note 7 Intangible assets under development

	December 31, 2019	December 31, 2018
Balance, beginning of year	$ 9,818	$ 8,125
Additions	826	1,693
Transfer to Intangible assets	(10,644)	-
Balance, end of year	$ -	$ 9,818

Note 8 Intangible assets

	December 31, 2019	December 31, 2018
Balance, beginning of year	$ -	$ -
Transfer from Intangible assets under development	10,644	-
Amortization	(532)	-
Balance, end of year	$ 10,112	$ -

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Note 9 Term loan and accrued interest on term loan

	December 31, 2019	December 31, 2018
Term Loan, beginning of year	$ 438,813	$ 391,963
Additions	-	46,850
Term Loan, end of year	438,813	438,813
Credit loss provision - Term Loan	(175)	(175)
Balance, end of year	$ 438,638	$ 438,638

	December 31, 2019	December 31, 2018
Accrued Interest on term loan, beginning of year	$ 152,105	$ 98,746
Additions	61,552	53,359
Accrued Interest on term loan, end of year	213,657	152,105
Credit loss provision - Accrued interest on term loan	(86)	(61)
Balance, end of year	$ 213,571	$ 152,044

This year the Commission did not lend any additional monies to NWRP ($46.850 million – 2018) as a term loan representing monthly drawdowns per the subordinated debt agreement. This term loan earns interest at a rate of prime plus six percent, compounded monthly, and will be repaid over 10 years starting one year after commercial start-up.

While loans to NWRP are outstanding APMC is entitled to a 25 percent voting interest on an Executive Leadership Committee, which is charged with overseeing and making decisions on the construction, start-up and operation of the Sturgeon Refinery.

Because of the 25 percent voting interest APMC has significant influence over NWRP. However the Commission has no equity ownership interest in NWRP. APMC will not equity account for the Sturgeon Refinery within the accounts of its financial statements.

Summarized audited financial information with respect to NWRP is presented below as of December 31, 2019. This information has been prepared in accordance with IFRS as issued by the IASB.

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	NWRP (100% Interest)	
	2019	2018
Current assets	$ 253,790	$ 209,974
Non-current assets	$ 11,323,677	$ 11,246,141
Current liabilities	$ 383,934	$ 351,894
Non-current liabilities	$ 11,311,691	$ 10,535,327
Partners' equity	$ (118,158)	$ 568,894
Revenue	$ 1,736,210	$ -
Net and comprehensive loss attributable to Partners	$ (687,052)	$ (16,624)

Non-current assets primarily consist of property plant and equipment, which includes: engineering; procurement activities; site construction costs; module fabrication; capitalized interest, and other costs directly attributable to the project. Non-current liabilities primarily include senior secured long term notes, credit facilities (with both Canadian and U.S. dollar denominated debt) and subordinated debt.

Effective January 1, 2019, the light oil refinery (LOR) units transitioned from commissioning and start-up to operations for accounting purposes and are processing synthetic crude oil into refined products. Revenues and expenses relating to the LOR units have been recognized in the Partnership's Consolidated Statements of Operations and Comprehensive Loss. NWRP continues the commissioning and start-up of its heavy oil units. The NWRP net loss and comprehensive loss in 2019 is attributable to operations as a LOR.

Note 10 Accounts payable

	December 31, 2019	December 31, 2018
Trade payables	$ 31,019	$ 35,598
GST	5,165	3,107
	$ 36,184	$ 38,705

Note 11 Due to the Department of Energy

	December 31, 2019	December 31, 2018
Due to Department, beginning of year	$ 2,707	$ 81,118
Amount to be transferred	870,778	1,042,638
Amount remitted	(788,899)	(1,121,049)
Due to Department, end of year	$ 84,586	$ 2,707

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Note 12 Short term debt

	December 31, 2019	December 31, 2018
Balance, beginning of year	$ 625,228	$ 391,963
Additions	206,622	233,265
Balance, end of year	$ 831,850	$ 625,228

Details related to additions are as follows:

Date Issued	Amount	Interest Rate	Due Date
Jan 02, 2018	$ 19,500	1.700%	Jan 02, 2019
Jan 31, 2018	12,500	1.750%	Jan 30, 2019
Feb 28, 2018	4,700	1.750%	Feb 27, 2019
Mar 29, 2018	3,551	1.780%	Mar 29, 2019
May 30, 2018	42	1.873%	May 30, 2019
Jun 25, 2018	40,454	1.845%	Jun 25, 2019
Jun 29, 2018	6,630	1.900%	Jun 28, 2019
Jul 25, 2018	22,058	2.002%	Jul 25, 2019
Jul 30, 2018	30	2.050%	Jul 30, 2019
Aug 24, 2018	23,988	2.140%	Aug 23, 2019
Aug 31, 2018	13	2.140%	Aug 30, 2019
Sep 25, 2018	22,358	2.199%	Sep 25, 2019
Sep 28, 2018	21	2.160%	Sep 27, 2019
Oct 25, 2018	25,512	2.305%	Oct 25, 2019
Oct 30, 2018	22	2.300%	Oct 30, 2019
Nov 26, 2018	22,726	2.310%	Nov 25, 2019
Nov 29, 2018	79	2.310%	Nov 28, 2019
Dec 20, 2018	201	2.122%	Dec 20, 2019
Dec 21, 2018	28,880	2.154%	Dec 20, 2019
	$ 233,265		

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Date Issued		Amount	Interest Rate	Due Date
Jan 02, 2019	$	263	2.103%	Jan 02, 2020
Jan 25, 2019		24,501	2.040%	Jan 24, 2020
Jan 30, 2019		26	2.015%	Jan 29, 2020
Feb 25, 2019		16,877	1.920%	Feb 24, 2020
Feb 27, 2019		26	1.915%	Feb 26, 2020
Mar 25, 2019		17,244	1.780%	Mar 23, 2020
Mar 29, 2019		7	1.770%	Mar 27, 2020
Apr 04, 2019		59	1.796%	Apr 02, 2020
Apr 25, 2019		17,201	1.799%	Apr 23, 2020
May 24, 2019		16,304	1.820%	May 22, 2020
May 30, 2019		23	1.795%	May 28, 2020
Jun 25, 2019		78	1.753%	Jun 23, 2020
Jun 25, 2019		15,234	1.754%	Jun 23, 2020
Jun 28, 2019		14	1.760%	Jun 26, 2020
Jul 25, 2019		16,813	1.748%	Jul 24, 2020
Jul 30, 2019		55	1.745%	Jul 28, 2020
Aug 23, 2019		90	1.670%	Aug 21, 2020
Aug 26, 2019		14,757	1.650%	Aug 24, 2020
Aug 30, 2019		134	1.630%	Aug 28, 2020
Sep 25, 2019		16,705	1.757%	Sep 24, 2020
Sep 27, 2019		37	1.780%	Sep 25, 2020
Oct 25, 2019		17,111	1.832%	Oct 23, 2020
Oct 30, 2019		171	1.851%	Oct 28, 2020
Nov 25, 2019		15,563	1.774%	Nov 23, 2020
Nov 28, 2019		92	1.790%	Nov 27, 2020
Dec 20 ,2019		17,237	1.854%	Jan 20, 2020
	$	206,622		

APMC is borrowing additional short term funds (with a one year term) from Treasury Board and Finance when these amounts come due (including principal and interest) and intends to repay the aggregated amounts starting the year after the Sturgeon Refinery's COD. The timing of APMC repaying this debt is expected to correspond to NWRP's repayment of the term loan to the Commission (see Note 9).

Note 13 Sturgeon refinery Processing Agreement provision

As discussed in Note 4(e) of these financial statements, APMC uses a cash flow model to assess if the net present value of the unavoidable costs related to the Processing Agreement with NWRP exceeds the economic benefits to be received. The model calculates the net present value of revenues from sales of refined products less feedstock costs and refinery tolls charged by NWRP under the Processing Agreement.

The net present value is most significantly influenced by two variables, pricing and on-stream factor. The definition of on-stream factor is the average percentage of time the refinery is operating.

APMC uses the Government of Alberta budget forecast values for WTI, WCS, condensate and foreign exchange to calculate the net present value. The single largest contributor to the decrease (74%) in the net present value of the contract year over year is due to lower forecasted future WTI prices for the life of the refinery and a significant narrowing of the Diesel-WCS spread for 2020 to 2022. Diesel prices are calculated as a premium to WTI. Feedstock prices are calculated as percentage discount to WTI. Therefore, with lower WTI prices the net present value will be less.

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Also contributing to the decrease in net present value is a lower expected on-stream factor.

The two most impactful pricing variables to the net present value of the contract are forecasted WTI prices and foreign exchange rates.

The net present value of the contract has a sensitivity to changes in WTI of +/- $134 million for every dollar change from the WTI forecast.

The net present value of the contract has a sensitivity to changes in foreign exchange, for every $0.01 the Canadian dollar changes from the forecast there is a +/- $117 million change to the net present value of the contract. If the Canadian dollar weakens in relation to the U.S. dollar, there is a positive impact to the net present value of the contract and conversely if the Canadian dollar strengthens in relation to the U.S. dollar, there is a negative impact to the net present value.

Note 14 Financial instruments

The Commission's financial instruments consist of cash and short term investments, accounts receivable, term loan, accrued interest on term loan, accounts payable, due to Department of Energy, short term debt, and accrued interest on short term debt. Refer to Note 3 b) for information on the adoption of IFRS 9 – Financial Instruments, effective January 1, 2018.

The Commission is exposed to a variety of financial risks: market risk (interest rate risk), credit risk, and liquidity risk. The nature of the risks faced by the Commission and its policies for managing such risks remains unchanged from December 31, 2018.

(a) Interest rate risk

Interest rate risk is the risk that the future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The Commission is subject to interest rate risk from fluctuations in rates on its cash balance (Note 5). For 2018 and 2019, a 100 basis point change would have a nominal effect on net income.

There is interest rate risk related to the term loans issued to NWRP. APMC earns interest at a rate of prime plus 6%, compounded monthly. A 100 basis point rise in prime would have improved 2019 finance income by $6.5 million (2018 $5.8 million). A 100 basis point decline in prime would have reduced 2019 finance income by $6.4 million (2018 $5.8 million).

(b) Credit risk

Credit risk is the risk of financial loss to the Commission if a customer or party to a financial instrument fails to meet its contractual obligation and arises principally from the Commission's cash and short term investments, accounts receivable and term loan. The maximum amount of credit risk exposure is limited to the carrying value of the balances disclosed in these financial statements.

The Commission manages its exposure to credit risk on cash and short term investments by placing these financial instruments with the Consolidated Cash Investment Trust Fund (Note 5).

A substantial portion of the Commission's accounts receivable are with its agents and customers in the oil and gas industry and are subject to normal industry credit risk. The Commission monitors the credit risk and credit rating of all customers on a regular basis. Aged receivable balances are monitored and a credit loss provision

is provided in the period in accordance with IFRS 9. See Note 6 for the provision amount. Any credit losses on accounts receivable would be charged on to the Department.

APMC has issued term loans totaling $439 million to NWRP. NWRP is an investment grade counterparty. Bonds issued by NWRP received a BBB+ credit rating (no change from 2018) from Standard and Poor's. For

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NWRP, this is subordinated debt which ranks behind senior secured debt. A trust structure has been set up under which APMC receives monies owed under the term loan after amounts owed to senior debt holders and certain other amounts have been paid. A credit loss provision for the term loan and related accrued interest has been provided in the period per IFRS 9. See Note 9 for the provision amount.

(c) Liquidity risk

Liquidity risk is the risk that the Commission will not be able to meet its financial obligations as they come due. The Commission actively manages its liquidity through cash and receivables strategies. In addition, APMC has the ability to obtain financing through external banking credit facilities or from Treasury Board and Finance.

The term loan is structured so that APMC will receive repayments starting one year after commercial start-up of the Sturgeon Refinery. The outstanding amount owed will be repaid straight line over a 10 year period with accrued interest.

For the short term debt APMC intends to borrow additional funds from Treasury Board and Finance and then to match the repayment terms detailed for the term loan above.

(d) Offsetting financial assets and liabilities

The Commission enters into contracts with single shipper pipelines, where APMC sells oil to the carrier at the inlet and purchases the oil back at the terminus of the pipeline. The agreements are written to allow for offsetting of accounts receivable and accounts payable, which are presented on a net basis on the statement of financial position. The following table presents the recognized financial instruments that are offset as a result of netting arrangements and the intention to settle on a net basis with counterparties.

	Gross amounts of recognized financial assets (liabilities)	Gross amounts of recognized financial assets (liabilities) offset in the statement of financial position	Net amounts of financial assets (liabilities) recognized in the statement of financial position
Accounts receivable (Note 6)	$88,564	$ 4,568	$ 83,996
Accounts payable (Note 10)	(42,538)	(6,354)	(36,184)
Net position, December 31, 2019	$ 46,026	$ (1,786)	$ 47,812
Accounts receivable (Note 6)	$ 20,182	$ 12,939	$ 7,243
Accounts payable (Note 10)	(54,910)	(16,205)	(38,705)
Net position, December 31, 2018	$ (34,728)	$ (3,266)	$ (31,462)

(e) Capital management

The capital structure includes the Commission's equity. The Commission's objectives when managing capital are to safeguard the Commission's ability to continue as a going concern and provide returns to the Department of Energy through responsible marketing of conventional crude oil royalty volumes and its other business activities. The Commission does not have any externally imposed restrictions on its capital. There has been no change in the Commission's capital management strategy.

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Note 15 Commitments

	2020	2021	2022	2023	2024	Beyond 2024	Total
NWRP Tolls	$ 557,000	$1,004,000	$1,021,000	$1,035,000	$1,006,000	$21,952,000	$26,575,000

(a) NWRP Tolls

On November 8, 2012, NWRP announced the sanctioning of the construction of Phase 1 of the Sturgeon Refinery which it will build, own and operate. The Commission has entered into agreements whereby NWRP will process 37,500 bbls/day of bitumen (55,000 bbls/day of diluted bitumen) into refined products. NWRP will market the refined products (primarily ultra low sulphur diesel and low sulphur vacuum gas oil) on behalf of the Commission. There is risk to the Commission under these agreements pertaining to the price differential between bitumen supplied as feedstock and marketed refined products, relative to the costs of the processing toll.

Under the processing agreement (PA), after Commercial Operations Date (COD), the Commission is obligated to pay a monthly toll comprised of: senior debt; operating; class A subordinated debt; equity; and incentive fees on 37,500 barrels per day of bitumen (75% of the project's feedstock). The Sturgeon Refinery did not attain COD in 2019, and per the PA, APMC and CNRL were required to start paying the debt toll (see Note 17) at the Toll Commencement Date (June 1, 2018). The PA has a term of 30 years starting with the Toll Commencement Date. The toll includes flow through costs as well as costs related to facility construction, estimated to be $10.1 billion (2018 - $9.925 billion).

The Commission has very restricted rights to terminate the agreement, and if it is terminated the Commission remains obligated to pay its share of the senior secured debt component of the toll incurred to date.

The nominal tolls under the processing agreement assuming: a $10.1 billion FCC; market interest rates; and 2% operating cost inflation rate, are estimated above. The total estimated tolls have decreased $199 million relative to 2018, due primarily to lower debt tolls.

No value has been ascribed to the anticipated refining profits available to APMC over the term of the agreement. In addition, no value has been credited for finance income net of finance costs on term loans outstanding to NWRP.

(b) NWRP Term loan

Under the agreements related to FCC for the Sturgeon Refinery, the financing structure is required to be 80% senior debt and 20% equity/subordinated debt. As part of the Subordinated Debt Facilities – Base and Additional agreements executed April 7, 2014, APMC is committed to provide 50% of the subordinated debt required to meet this test. This commitment relates to incremental FCC from April 7, 2014 until six months after COD, when FCC is finalized.

Up to 6 months after COD the calculation of the 80/20 ratio does not allow for the deduction of cumulative debt service costs (accrued interest) which could result in a temporary need for additional subordinated debt lending by APMC. A final reconciliation of the amount of subordinated debt required will be done six months after COD at which time the calculation does allow for the deduction of accumulated debt service costs which would result in monies being returned to APMC.

Management is forecasting APMC to provide NWRP no additional subordinated debt. As part of the final subordinated debt true-up six months after COD, the Commission anticipates NWRP will repay $100 million to APMC.

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Note 16 Related party transactions

The Department pays the Commission a fee to market crude oil on its behalf under conventional crude oil marketing activities, reported as marketing fees within the statement of income (loss) and comprehensive income (loss). The amounts owing to the Department have been disclosed in Note 11.

The Commission enters into transactions with the Department of Energy, a related party, in the normal course of business. The Department incurs costs for salaries on behalf of the Commission, as recognized under wages and benefits 2019 $2,200 (2018 - $2,084) and software and maintenance 2019 $ 0 (2018 - $39) within the statement of income (loss) and comprehensive income (loss). In addition, some of the Department salaries have been capitalized within intangible assets 2019 $79 (2018 - $154).

Starting in April 2018, Service Alberta, a related party provided the software and maintenance services totaling $453 in 2019 (2018 - $70). These expenditures are recognized within the statement of income (loss) and comprehensive income (loss). In addition their technology services related to software development totaling $598 in 2019 (2018 - $905) have been capitalized within intangible assets.

The Commission has outstanding short term debt with Treasury Board and Finance. For more details see Note 12.

The Board members of the Commission, executive management and their close family members are deemed related parties of the Commission. Transactions with close family members are immaterial; compensation for Board members and executive management is disclosed in Note 18.

Note 17 Debt tolls expense

APMC, as a toll payer of the Sturgeon Refinery, has an obligation to pay 75% of the debt service costs related to the financing of the Facility Capital Costs (FCC). Per the Processing Agreement (PA), this payment obligation started June 1, 2018 and will continue to the end of the 30 year initial term of the PA, at which point the debt related to the FCC will be fully paid. The debt toll expensed by APMC for the year ended December 31, 2019 is $200,935 ($209,601 – 2018).

Note 18 Salaries and benefit disclosure

Key management personnel include the Commission's Chief Executive Officer, Director of Operations, Director of Finance and Board Members. The amounts in the financial statements relating to board members and key management compensation in 2019 and 2018 are as follows:

	2019				2018
	Base Salary	Other Cash Benefits (2)	Other Non-cash Benefits (3)	Total	Total
Board Members (1)	$ -	$ 96	$ -	$ 96	$ 49
Chief Executive Officer	301	94	6	401	373
Executive Director, Business Development (4)	217	42	5	264	393
Director of Operations (5)	200	39	4	243	-
Director of Finance	234	25	4	263	263

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(1) The Chair of the Board (Deputy Minister, Department of Energy) and one director (Assistant Deputy Minister, Department of Energy) are unpaid. Three outside Board Members were added in the 1st quarter of 2019. One outside Board Member's term expired in the 1st quarter of 2019. The outside Board Members receive an annual retainer and meeting fees.
(2) As per their employment contracts, the four key management personnel receive cash payments in lieu of benefits. No bonuses were paid during the year.
(3) Included in Other Non-cash benefits is parking.
(4) The Executive Director, Business Development resigned effective October 11, 2019.
(5) The Director of Operations was hired effective March 31, 2019.

Note 19 Subsequent events

Short term debt

On January 2, 2020, APMC replaced its short term debts of $122.621 million originally issued January 2, 2019 with new short term debt of $125.204 million at 1.789% interest due February 3, 2020.

On January 20, 2020, APMC replaced its short term debts of $166.737 million originally issued December 20, 2019 with new short term debt of $166.996 million at 1.799% interest due January 19, 2021.

On January 24, 2020, the Commission borrowed $21.221 million of short term debt from Treasury Board and Finance and replaced its short term debts of $24.502 million originally issued January 25, 2019. The two debts were combined into one new short term debt of $46.221 at 1.743% interest due January 22, 2021.

On January 29, 2020, APMC replaced its short term debt of $12.744 million originally issued January 30, 2019 with new short term debt of $13.003 million at 1.725% interest due January 28, 2021.

On February 3, 2020, APMC replaced its short term debt of $125.204 million originally issued January 2, 2020 with new short term debt of $125.412 million at 1.713% interest due February 2, 2021.

On February 24, 2020, APMC replaced its short term debt of $16.877 million originally issued February 25, 2019 with new short term debt of $17.212 million at 1.670% interest due February 23, 2021.

On February 25, 2020, APMC borrowed $17.903 million of short term debt from Treasury Board and Finance at an effective interest rate of 1.660% due February 24, 2021.

On February 26, 2020, APMC replaced its short term debt of $4.808 million originally issued February 27, 2019 with new short term debt of $4.901 million at 1.650% interest due February 25, 2021.

On March 23, 2020, APMC replaced its short term debt of $17.244 million originally issued March 25, 2019 with new short term debt of $19.996 million at 1.147% interest due March 30, 2020.

On March 25, 2020, APMC borrowed $14.889 million of short term debt from Treasury Board and Finance at an effective interest rate of 1.499% due September 23, 2020.

On March 27, 2020, APMC replaced its short term debt of $3.621 million originally issued March 29, 2019 with new short term debt of $4.986 million at 1.098% interest due June 26, 2020.

On March 30, 2020, APMC replaced its short term debt of $19.996 million originally issued March 23, 2020 with new short term debt of $19.955 million at 0.899% interest due June 30, 2020.

On April 2, 2020, APMC replaced its short term debt of $118.282 million originally issued April 4, 2019 with 3 new short term debts. The first debt of $20.963 million was at 0.692% interest due July 3, 2020. The second debt of $24.915 million was at 0.759% interest due September 14, 2020. The third debt of $74.726 million was at 0.731% due October 2, 2020.

Notes to the Financial Statements

Alberta Petroleum Marketing Commission
(in thousands of Canadian dollars unless otherwise noted)

On April 3, 2020, APMC borrowed $13.143 million of short term debt from Treasury Board and Finance at an effective interest rate of 0.6998% due April 2, 2021.

On April 3, 2020, APMC borrowed $41.127 million of short term debt from Treasury Board and Finance at an effective interest rate of 1.2724% due January 28, 2021.

On April 23, 2020, APMC borrowed $17.299 million of short term debt from Treasury Board and Finance and replaced its short term debts of $17.201 million originally issued April 25, 2019. These two debts were combined into one new short term debt of $34.809 million at 0.550% interest due April 22, 2021.

On May 22, 2020, APMC borrowed $17.000 million of short term debt from Treasury Board and Finance and replaced its short term debts of $16.600 million originally issued May 24, 2019. These two debts were combined into one new short term debt of $34.854 million at 0.420% interest due May 21, 2021.

On May 28, 2020, APMC replaced its short term debt of $21.623 million originally issued May 30, 2019 with new short term debt of $19.918 million at 0.410% interest due May 28, 2021

On June 22, 2020, APMC borrowed $35.874 million of short term debt from Treasury Board and Finance at an effective interest rate of 0.350% due June 22, 2021.

On June 23, 2020, APMC replaced two short term debts of $15.500 million and $42.000 million originally issued June 25, 2019 with one new short term debt of $35.875 million at 0.350% interest due June 21, 2021.

On June 25, 2020, APMC borrowed $22.323 million of short term debt from Treasury Board and Finance at an effective interest rate of 0.350% due June 21, 2021.

On June 26, 2020, APMC repaid Treasury Board and Finance the $13.460 million to settle two short term debts of $8.460 million and $5.000 million originally issued June 28, 2019 and Mar 27, 2020 respectively.

On June 30, 2020, APMC replaced its short term debt of $20.000 million originally issued March 30, 2020 with new short term debt of $20.030 million at 0.350% interest due June 30, 2021.

On July 2, 2020, APMC borrowed $99.754 million of short term debt from Treasury Board and Finance at an effective interest rate of 0.330% due April 1, 2021.

On July 2, 2020, APMC borrowed $54.118 million of short term debt from Treasury Board and Finance at an effective interest rate of 0.340% due June 28, 2021.

On July 3, 2020, APMC replaced its short term debt of $21.000 million originally issued April 2, 2020 with new short term debt of $21.030 million at 0.340% interest due June 28, 2021.

KXL Investment

An Investment Agreement between TransCanada Pipelines Limited (TCPL) and APMC was executed on March 31, 2020. APMC, through newly created subsidiaries, has agreed to provide financial support for the construction of the KXL Expansion pipeline. The Commission will extend US$ 5.3 billion of funding support beginning with an equity commitment of up to US$ 1.06 billion in 2020. The balance of the support, commencing January 1, 2021, will be in the form of a debt guarantee to backstop TCPL's financing for the KXL Expansion pipeline.

Notes to the Financial Statements

Alberta Petroleum Marketing Commission
(in thousands of Canadian dollars unless otherwise noted)

APMC acquired its initial interest in the KXL Expansion Pipeline effective March 31, 2020 in exchange for its agreement to make initial equity contributions of US$48,245 and $33,927 by way of cash contributions of US$29,081 and $13,143 and through second quarter loans from TCPL for the month of April 2020, of an additional US$19,164 and $20,784. APMC satisfied the payment of its initial equity contributions on April 3, 2020. For the 2nd quarter of 2020, TCPL is lending APMC the funds required to make APMC's monthly funding contributions. APMC has executed non-interest bearing promissory notes to TCPL in connection with this funding. APMC will repay the 2nd quarter loans to TCPL in six equal monthly installments, commencing July 2020, concurrent with APMC's monthly contributions for Q3 and Q4.

APMC will earn accretion on its equity contributions paid until March 31, 2026 at a rate of 6% per annum, increasing to 10% per annum on and after September 1, 2033, if the KXL pipeline is not in-service, with a minimum guaranteed rate of 4% per annum when APMC's equity contributions are repurchased by TCPL. In addition, the Commission will earn a loan guarantee fee (0.50% of TCPL's debt outstanding, subject to escalation if the loan guarantee is outstanding 480 days following project completion) starting in 2021 when TCPL obtains debt financing. Approximately one year after project completion, TCPL will pay to APMC the value of the outstanding equity contributions and accretion earned thereon. TCPL will pay the loan guarantee fee at the same time as the Commission's debt guarantees are released. This is also anticipated to occur approximately one year after project completion.

Coronavirus (COVID19)

Since December 31, 2019, the outbreak of the coronavirus has caused global economic uncertainty, which may affect prices and demand for the Sturgeon Refinery's refined products, temporarily disrupt supply chain and transportation services or result in a temporary loss of skilled labour. This may cause temporary operational reductions and higher costs. The duration and severity of these developments remain unknown but may have an impact on the financial results of APMC in future periods.

Similarly, COVID19 may affect the cost and timing of when the KXL Expansion pipeline comes into service. The duration and severity of these developments remain unknown but may have an impact on the financial results of APMC in future periods.

Sturgeon refinery Processing Agreement provision

The provision was recalculated for the Ministry of Energy's financial statement date, March 31, 2020. The provision as of this date was $2.522 billion. The change from what was recorded in these financial statements ($1.727 billion) entirely relates to changes in future market prices. The unprecedented volatility in the markets is due to COVID19 and the Russia-Saudi Arabia oil price war.

Sturgeon Refinery

In April 2020, the Refinery successfully transitioned from primarily processing synthetic crude feedstock to bitumen feedstock and reached commercial operations in May 2020. As a result, the criteria to achieve a June 1, 2020 Commercial Operation Date ("COD") was achieved. COD is defined in the Processing Agreements as "the first Day of the Month immediately following the Month, in which, for the first time, the Facility has for 30 consecutive Days (which may span more than one Month) received and processed into the products intended to be produced therefrom a quantity of Bitumen that is not less than 50% of the Design Capacity."

Balancing Pool

Financial Statements

Year ended December 31, 2019

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Independent auditor's report

To the Board of Directors of the Balancing Pool

Our opinion

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Balancing Pool as at December 31, 2019 and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRS).

What we have audited
The Balancing Pool's financial statements comprise:

- the statement of financial position as at December 31, 2019;
- the statement of income and comprehensive income for the year then ended;
- the statement of cash flows for the year then ended; and
- the notes to the financial statements, which include a summary of significant accounting policies.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence
We are independent of the Balancing Pool in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

Other information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis.

Our opinion on the financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

PricewaterhouseCoopers LLP
111-5th Avenue SW, Suite 3100, Calgary, Alberta, Canada T2P 5L3
T: +1 403 509 7500, F: +1 403 781 1825

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Balancing Pool's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Balancing Pool or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Balancing Pool's financial reporting process.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Balancing Pool's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Balancing Pool's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Balancing Pool to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

[Original signed by]

Chartered Professional Accountants

Calgary, Alberta
April 17, 2020

Statement of Financial Position

Balancing Pool

(in thousands of Canadian dollars)	2019	2018
Assets		
Current assets		
Cash and cash equivalents	96,037	175,851
Trade and other receivables (Note 5)	85,650	201,250
Current portion of long-term receivables (Note 6)	1,980	1,980
Current portion of Hydro Power Purchase Arrangement (Note 8 b i)	110,667	89,343
Right-of-use assets (Note 9)	289,921	-
Intangible assets (Note 7)	2,500	26,899
	586,755	495,323
Long-term receivables (Note 6)	-	1,961
Right-of-use assets (Note 9)	89	-
Property, plant and equipment	14	4
Hydro Power Purchase Arrangement (Note 8 b i)	-	45,997
Total Assets	586,858	543,285
Liabilities		
Current liabilities		
Trade payables and other accrued liabilities (Note 11)	212,524	305,357
Current portion of related party loan (Note 18)	202,765	412,402
Current portion of Small Power Producer Contracts (Note 8 b ii)	-	444
Current portion of reclamation and abandonment provision (Note 12)	676	1,680
Current portion of lease liability (Note 13)	410,025	-
Current portion of other long-term obligations (Note 14)	-	79,723
	825,990	799,606
Reclamation and abandonment provision (Note 12, Note 16)	32,183	22,482
Other long-term obligations (Note 14)	-	164,760
Lease liability (Note 13)	91	-
Related party loan (Note 18)	503,219	502,893
Total Liabilities	1,361,483	1,489,741
Net liabilities attributable to the Balancing Pool deferral account (Note 1, 15)	(774,625)	(946,456)
Contingencies and commitments (Note 16)		
Subsequent events (Note 19)		

On behalf of the Balancing Pool:

[Original signed by]

Greg Clark, *Chair*

[Original signed by]

Greg Pollard, *Audit and Finance Committee Chair*

The accompanying notes are an integral part of these financial statements.

Statement of Income and Comprehensive Income

Balancing Pool

(in thousands of Canadian dollars)	2019	2018
Revenue from contracts with customers		
Sale of electricity and ancillary service (Note 3, Note 18)	882,584	969,596
Consumer collection (Note 3)	172,985	189,259
	1,055,569	1,158,855
Other income from operating activities		
Changes in fair value of Hydro Power Purchase Arrangement (Note 8 b i)	20,152	44,258
Payments in Lieu of Tax (Note 16)	21,149	130,784
Interest income	2,341	1,362
Changes in fair value of Small Power Producer Contracts (Note 8 b ii)	393	1,007
Changes in fair value of investments	-	4
	44,035	177,415
Expenses		
Cost of sales (Note 17)	871,966	843,212
Reclamation and abandonment provision (Note 12, Note 16)	10,544	10,526
Mandated costs (Note 18)	4,700	4,476
General and administrative	5,155	4,217
Force majeure, other PPA costs and PPA provision	123	122,988
	892,488	985,419
Income from operating activities	207,116	350,851
Other income (expense)		
Finance expense (Note 10)	(35,391)	(16,417)
Other income	106	108
	(35,285)	(16,309)
Change to the Balancing Pool deferral account (Note 15)	171,831	334,542

The accompanying notes are an integral part of these financial statements.

Statement of Cash Flows

Balancing Pool

(in thousands of Canadian dollars)	2019	2018
Cash flow provided by (used in)		
Operating activities		
Change to the Balancing Pool deferral account	171,831	334,542
Adjustments for		
Amortization and depreciation (Note 9)	299,660	23
Reclamation and abandonment provision (Note 12)	10,544	10,526
Power Purchase Arrangement provision (Note 14)	(2,132)	(413,238)
Line loss provision (Note 11, 16)	(32,191)	(3,066)
Fair value changes on Small Power Producer Contracts (Note 8 b ii)	(393)	(1,007)
Fair value changes on Hydro Power Purchase Arrangement (Note 8 b i)	(20,152)	(44,258)
Fair value changes on investments	-	1
Finance expense (Note 10)	35,391	16,417
Emission credits retired (Note 7)	89,279	159,754
Reclamation and abandonment expenditures (Note 12)	(2,299)	(8,333)
Net change in other assets:		
Long-term receivable (Note 6)	1,961	1,941
Net change in non-cash working capital:		
Trade and other receivables	115,599	(71,126)
Trade payable and other accrued liabilities	(92,832)	(253,289)
Net cash provided by (used in) operating activities	574,266	(271,113)
Investing activities		
Interest and other gains	-	(89)
Sale of investments	-	12,458
Purchase of property, plant and equipment	(16)	-
Purchase of emission credits (Note 7)	(64,879)	(33,533)
Net cash used in investing activities	(64,895)	(21,164)
Financing activities		
Hydro Power Purchase Arrangement net receipts (Note 8 b i)	77,016	86,734
Lease payments (Note 13)	(437,891)	-
Payments on related party loan (Note 18)	(1,057,750)	(3,211,633)
Proceeds from issue of related party loan (Note 18)	829,491	3,544,526
Small Power Producer Contracts net payments (Note 8 b ii)	(51)	(2,271)
Net cash provided by (used in) financing activities	(589,185)	417,356
Change in cash and cash equivalents	(79,814)	125,079
Cash and cash equivalents, beginning of year	175,851	50,772
Cash and cash equivalents, end of year	96,037	175,851

The accompanying notes are an integral part of these financial statements.

Notes to Financial Statements

Balancing Pool

1. Reporting Entity and Nature of Operations

Formation and Duties of the Balancing Pool

The Balancing Pool exists to facilitate policy implementation and to support the functioning of the electricity industry for the benefit of Albertans. The *Electric Utilities Act (2003)* ("EUA") and certain regulations made under it establish the mandate of the Balancing Pool, which is principally to manage certain assets, liabilities, revenues, and expenses associated with the ongoing evolution of Alberta's electric industry.

The Balancing Pool was originally established in 1998 as a separate financial account of the Power Pool Council (the "Council") and commenced operations in 1999. The Council was a statutory corporation established under the *Electric Utilities Act of Alberta (1995)*. With the proclamation of the EUA on June 1, 2003, the Balancing Pool was established as a separate statutory corporation (the "Corporation"). The assets and liabilities of the Council that related to the duties, responsibilities and powers of the Balancing Pool were transferred to the Corporation.

Under the EUA, the Corporation is required to operate with no profit or loss (Note 15) and no share capital for the Corporation has been issued. The Balancing Pool Board of Directors (the "Board") consists of individual members who are independent of persons having a material interest in the Alberta electric industry. The members of the Board are appointed by the Minister of Energy of the Government of Alberta ("Minister of Energy").

The Balancing Pool is required to respond to certain extraordinary events during the operating period of all of the Power Purchase Arrangements ("PPAs") such as force majeure, unit destruction, Buyer or Owner default or termination of a PPA. In situations resulting in termination of a PPA by a Buyer, the Balancing Pool will assume all remaining rights and obligations pursuant to that PPA, assuming the PPA continues. The Balancing Pool acted as Buyer of the PPAs that were not sold at the public auction held by the Government of Alberta in August 2000, assuming all rights and obligations of a Buyer of these PPAs. Under the EUA the Balancing Pool is required to manage generation assets in a commercial manner.

The head office and records of the Balancing Pool are located at Suite 2350, 330 - 5th Avenue S.W., Calgary, Alberta, Canada.

Activities of the Balancing Pool

The initial allocation of assets and liabilities to the Balancing Pool was charged to a deferral account. Differences between annual revenues and expenditures are also charged or credited to the Balancing Pool deferral account.

The EUA requires that the Balancing Pool forecast its revenues and expenses. Any excess or shortfall of funds in the accounts is to be allocated to, or provided by, electricity consumers over time.

In late 2016, following the PPA terminations, the Government of Alberta enacted changes to the EUA that allow the Treasury Board to make loans to the Balancing Pool at the recommendation of the Minister of Energy and to guarantee the Balancing Pool's obligations. Any cash shortfall that the consumer collection is unable to satisfy will be financed by funds obtained through the loan agreement with the Government of Alberta and subsequently recovered from electricity consumers over the period of January 1, 2017 to December 31, 2030 (Note 18).

Notes to Financial Statements

Balancing Pool

The thermal PPAs and Hydro PPA expire on December 31, 2020. The Balancing Pool's business activities after December 31, 2020 will include the collection of funds from electricity consumers, the repayment of the outstanding loan with the Provincial government, resolving outstanding commercial and regulatory disputes related to the PPAs, resolving other legal matters, and settlement of certain financial accounts.

Revenue from Contracts with Customers

i) Sale of electricity, ancillary service and generating capacity

The Balancing Pool earns or earned revenue from the sale of electricity and ancillary service sourced from the PPAs it holds or held, namely, Genesee, Sheerness and Keephills (2018 – Genesee, Battle River 5, Sheerness, Keephills, Sundance B and Sundance C).

Electricity that is not otherwise contracted is sold into the spot market. Ancillary services from the PPAs are sold to the Alberta Electric System Operator ("AESO") through a competitive exchange.

ii) Consumer collection

Pursuant to Section 82 of the EUA, the Balancing Pool collects or allocates an annualized amount from customers. Consumer collection from the AESO is being accounted for as revenue of the Balancing Pool. The Balancing Pool has applied judgment in determining that the consumer collection collected via rate Rider F, as specified in the EUA, is analogous to a contract with a customer. The legislation contained in the EUA established the Balancing Pool's right to recover operating shortfalls from electricity customers via Rider F of the AESO tariff and can be interpreted as a contract with a customer.

Other Income

i) Hydro Power Purchase Arrangement ("Hydro PPA")

Pursuant to Section 85 of the EUA, the Balancing Pool holds the Hydro PPA. As such, the Balancing Pool has retained the right to the market value of the associated electricity and is responsible for the PPA obligations from certain hydro plants in the Province of Alberta. The cash flows associated with the Hydro PPA are based on the electricity market price multiplied by a notional amount of production less PPA obligations as outlined in the PPA. The expected net present value of these estimated payments is recorded as an asset and any revaluation adjustment is included in net results of income (loss).

ii) Investment income and changes in fair value of investments

Cash, cash equivalents and investments held by the Balancing Pool generate investment income consisting of interest, dividends and capital gains and losses.

iii) Payments (refunds) in Lieu of Tax ("PILOT")

Pursuant to Section 147 of the EUA, the Balancing Pool collects (refunds) a notional amount of tax from electricity companies controlled by municipal entities that are active in Alberta's competitive electricity market and are otherwise exempt from the payment of tax under the *Income Tax Act* or the *Alberta Corporate Tax Act*. The Balancing Pool does not calculate instalment payments or refunds and it does not audit PILOT filings. PILOT instalments are calculated by the payer and PILOT filings are subject to audit by Alberta Tax and Revenue.

Notes to Financial Statements

Balancing Pool

Expenses

i) Cost of sales

Under the terms of the various PPAs, the Balancing Pool is obligated to pay certain fixed and variable costs to the Owners of the various generation assets.

ii) Small Power Producer ("SPP") Contracts

Under the provisions of the *Small Power Research and Development Act*, public utilities were required to enter into production contracts with small power producers who own and operate eligible power production facilities.

Under the provisions of the *Independent Power and Small Power Regulation*, the Balancing Pool must pay to the public utility any deficit or receive any surplus realized by the public utility from the production contracts. The net present value of these estimated payments is recorded as a liability and any revaluation adjustment is included in net results of income.

iii) Other costs

Under the terms of government legislation, the Balancing Pool is obligated to make payments to certain entities for such matters as reclamation and abandonment and force majeure. The Minister of Energy may direct the Balancing Pool to fund specific payments under Section 148 of the EUA, which amounts are included in mandated costs.

2. Basis of Presentation

These financial statements for the year ended December 31, 2019 have been prepared by management in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and include as comparative information the year ended December 31, 2018.

These financial statements were authorized and approved for issue by the Board of the Balancing Pool on April 17, 2020.

Certain comparative amounts have been reclassified to conform to the current presentation.

3. Summary of Significant Accounting Policies

The significant accounting policies used in the preparation of these financial statements are as follows:

Basis of Measurement

These financial statements have been prepared on a historical cost convention, except for the revaluation of certain financial instruments, which are measured at fair value.

Notes to Financial Statements

Balancing Pool

Change in Accounting Policy

The Balancing Pool adopted IFRS 16, *Leases* on January 1, 2019. The purpose of IFRS 16 is to provide a foundation for users of financial statements to evaluate the amount, timing and uncertainty of cash flows arising from leases. IFRS 16 provides a single lessee accounting model, requiring lessees to recognize right-of-use assets and lease liabilities for all leases unless the lease term is 12 months or less or the underlying asset has a low value.

Management has reviewed all contracts and existing lease arrangements and determined the impact of adopting IFRS 16. Management has determined that the Genesee, Keephills and Sheerness PPAs contain lease arrangements. The PPAs have transitioned to IFRS 16 effective January 1, 2019 from their previous accounting treatment as onerous contracts. The Balancing Pool has also accounted for its office lease under IFRS 16.

Management has elected the following practical expedients allowable under IFRS 16:

1. Not to separate non-lease components from lease components, and instead account for each lease component and any associated non-lease components as a single lease.
2. To use the modified retrospective transition method where the prior period is not restated.
3. To adjust the right-of-use asset for previously recognized onerous lease provisions, instead of performing an impairment review. The right-of-use asset shall be reduced by the amount of the provision for onerous leases recognized in the statement of financial position immediately before the date of transition.

Lease liabilities are measured at the present value of the remaining lease payments for the PPAs and the office lease. The lease liabilities have been discounted at the Balancing Pool's borrowing rate of 1.9% at January 1, 2019. A lease liability of $841.7 million has been recognized for the PPAs on adoption of IFRS 16.

Right-of-use assets of $599.4 million have been recognized for the PPAs on adoption of IFRS 16. The right-of-use assets will be amortized on a straight-line basis over the remaining life of the PPAs. The right-of-use assets have been impaired on transition to IFRS 16 to account for the onerous contract status of the PPAs. The difference between the right-of-use assets and the lease liability for the PPAs of $242.4 million represents the net present value of the anticipated losses of the PPAs for 2019 and 2020.

Revenue from Contracts with Customers

The Balancing Pool adopted IFRS 15, *Revenue from contracts with customers*, for its revenue arrangements.

(a) Sale of electricity and ancillary services

Revenues from the sale of electricity and ancillary services are recognized on an accrual basis in the period in which generation occurred, which is the point in time when control of the goods and services passes to the customer. Sale of electricity and ancillary services is measured at the fair value of the consideration received or receivable. The Corporation has elected to recognize revenue based on amounts invoiced.

The timing of revenue recognition does not result in any contract assets or liabilities and there are no unfulfilled performance obligations at any point in time. Furthermore, no significant judgments or estimates are required with respect to the recognition of revenue associated with the sale of electricity and ancillary services.

Notes to Financial Statements

Balancing Pool

(b) Consumer collection (allocation)

Upon adoption of IFRS 15, consumer collection revenue is recognized in the statement of income and comprehensive income on an accrual basis in the period in which amounts are charged (refunded) to electricity customers based on an annualized tariff amount, which is the point in time when control of the goods and services passes to the customer. Consumer collection revenue is measured at the fair value of the consideration received or receivable. The Corporation has elected to recognize revenue based on amounts invoiced.

The timing of revenue recognition does not result in any contract assets or liabilities and there are no unfulfilled performance obligations at any point in time. The Balancing Pool has applied judgment in the application of its accounting policy that the consumer collection (allocation) represents a contract with a customer in the scope of IFRS 15 (see Note 1).

Other Income (Expense) Recognition

(a) Hydro Power Purchase Arrangement

The Hydro PPA is recorded at the present value of the estimated future net receipts under this PPA. The increase in value of this asset with the passage of time (accretion) is recognized on an accrual basis. Any change in valuation as a result of changes in underlying assumptions is recognized in income (loss) from operating activities.

(b) Small Power Producer Contracts

SPP contracts are recorded at the present value of the estimated future net payments to be received (or paid) under these contracts. The change in value of this liability with the passage of time (accretion) is recognized on an accrual basis. Any change in valuation as a result of changes in underlying assumptions is recognized in income from operating activities.

(c) Investment income and changes in fair value of investments

Investment income resulting from interest and dividends is recorded on an accrual basis when there is reasonable assurance as to its measurement and collectability. Investment income also includes realized and unrealized gains and losses on investments sold and realized foreign currency exchange rate gains and losses on sale of foreign investments excluding fund management fees.

(d) Payments (refunds) in Lieu of Tax

PILOT funds are accrued based on instalments received from or refunds paid to a municipal entity for a particular tax year. PILOT payments are calculated by the municipal entities and are subject to assessment and audit by Alberta Tax and Revenue Administration. Adjustments, if any, arising from audits, or other legal proceedings, are recorded in the current year, upon receipt.

Income Taxes

No provision has been made for current or deferred income tax as the Balancing Pool is exempt from Federal and Provincial income tax.

Notes to Financial Statements

Balancing Pool

Cash and Cash Equivalents

Cash and cash equivalents are comprised of cash on deposit at the bank.

Trade and Other Receivables

Trade and other receivables are classified and measured at amortized cost less any impairment.

Intangible Assets (Emission Credits)

Emission credits, which have been purchased or have been acquired through PPA-negotiated settlements, and which are held for compliance purposes, are recorded by the Balancing Pool as limited life intangible assets. Emission credits are limited to a life between six to eight years depending on the vintage. These assets are recognized initially at fair value based upon a market price. Purchased emissions credits are measured at cost on the purchase date. Emission credits held for compliance purposes are not amortized, but are expensed as the associated benefits are realized.

The emission credits are expected to be used to satisfy future environmental compliance obligations of the PPAs associated with the *Carbon Competitiveness Incentive Regulation*. Compliance obligations resulting from emissions are recognized as a provision and measured at the market value of allowances needed to settle the obligation.

Long-Term Receivables

Cash settlement amounts due from a former PPA counterparty are accounted for as long-term receivables with fixed payments receivable on December 31, 2020. These assets were recognized initially at fair value. After initial recognition they are measured at amortized cost using the effective interest method less any impairment losses. The effective interest method calculates the amortized cost of a financial asset and allocates the interest income over the term of the financial asset using the effective interest rate.

Hydro Power Purchase Arrangement and Small Power Producer Contracts

The Hydro PPA and SPP Contracts are derivative financial instruments classified as and measured at fair value through profit or loss. They are recorded as of the period end date at their fair value. Fair value is measured as the present value of the estimated future net payments to be received (or paid) under the contracts and reflects management's best estimate based on generally accepted valuation techniques and supported by observable market prices and rates when available. Fair value for these contracts is based on forecasted future prices.

Electricity Price Risk Management – Risk Management Asset and Liabilities

The Balancing Pool may utilize swap contracts to manage its exposure to electricity price fluctuations which require payments to (or receipts from) counterparties based on the differential between fixed and floating prices for electricity and other contractual arrangements. The estimated fair value of all derivative instruments is based on reported values in the electricity forward market.

Derivative financial instruments are classified and measured at fair value through profit or loss and are recorded at fair value. All changes in fair value are included in results of income.

Notes to Financial Statements

Balancing Pool

Property, Plant and Equipment ("PP&E")

PP&E are stated at cost less accumulated depreciation and accumulated impairment losses. Cost includes expenditure directly attributable to the acquisition of the asset. When parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment. Gains and losses on disposal of an item of property, plant, and equipment are determined by comparing the proceeds from disposal with the carrying amount of PP&E, and are recognized within other income in profit and loss. PP&E, which comprises office equipment, is depreciated on a straight-line basis over a three to five year useful life.

Impairment – Non-Financial Assets

For the purpose of impairment testing, non-financial assets are grouped together into the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets – a cash generating unit ("CGU").

The carrying amounts of non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment, such as decreased forward electricity prices. If any such indication exists, then the amount recoverable from the asset is estimated. The recoverable amount is the greater of the value in use or fair value less costs to dispose.

Value in use is based on the estimated net future cash flows discounted to their present value. The discounted cash flow is determined using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. The recoverable amount is generally computed by reference to the present value of the future cash flows. An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in the Statement of Income and Comprehensive Income.

Impairment losses recognized in prior years are reassessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation and amortization, if no impairment loss had been permitted to be recognized.

Impairment – Financial Assets

The Corporation applies IFRS 9, *Simplified approach to measuring expected credit losses*, which uses a lifetime expected loss allowance for all trade and other receivables. To measure the expected credit losses, trade receivables and other receivables have been grouped based on shared credit risk characteristics and the days past due.

Trade and other receivables are written off when there is no reasonable expectation of recovery. Indicators that there is no reasonable expectation of recovery include, amongst others, the failure of a debtor to engage in a repayment plan with the Corporation, and a failure to make contractual payments for a period of greater than 120 days past due.

No impairment provision has been recorded at December 31, 2019 related to trade and other receivables. The Corporation considers trade and other receivables to be low risk.

Notes to Financial Statements

Balancing Pool

Reclamation and Abandonment Obligations

Reclamation and abandonment obligations include legal obligations requiring the Balancing Pool to fund the decommissioning of tangible long lived assets such as generation and production facilities. A provision is made for the estimated cost of site restoration.

Reclamation and abandonment obligations are measured as the present value of management's best estimate of expenditures required to settle the present obligation at the period end date. Subsequent to the initial measurement, the obligations are adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as a finance expense. Increases / decreases due to changes in the estimated future cash flows are expensed. Actual costs incurred upon settlement of the reclamation and abandonment obligations are charged against the provision to the extent the provision was established.

The Balancing Pool's estimates of reclamation and abandonment obligations are based on reclamation standards that meet current regulatory requirements. The estimate of the total liability of future site restoration costs may be subject to change based on amendments to laws and regulations. Accordingly, the amount of the liability will be subject to re-measurement at each period end date.

The Balancing Pool has recorded an estimate of the cost to remediate certain Isolated Generating Unit sites in Alberta. Actual expenditures incurred to remediate these sites will reduce this liability and any increase in this liability will be charged to expense when estimated costs are known to exceed the remaining liability balance.

An amount has also been provided for the decommissioning of the H.R. Milner generating station which is being accreted annually; revisions to this estimate will be charged or credited to net results of income (loss).

Pursuant to Section 5 of the *Power Purchase Arrangements Regulation*, the Owner of a generating unit who applies to the Alberta Utilities Commission ("AUC") to decommission a unit within one year of the termination of the PPA is entitled to receive from the Balancing Pool the amount by which the decommissioning costs exceed the amount the Owner collected from consumers before January 1, 2001 and subsequently through a PPA, provided that the unit has ceased generating electricity and subject to AUC approval. Section 5 of the *Power Purchase Arrangements Regulation* does not apply after December 31, 2018.

The reclamation and abandonment provision includes an estimate of the expected future costs associated with PPA decommissioning costs. Any underfunded decommissioning liabilities are passed to the Balancing Pool in circumstances where a plant Owner elects to discontinue operations and decommission the respective plant following a PPA termination or PPA expiry.

The discount rate used to value these liabilities is based upon the risk-free rate and adjusted for other risks associated with these liabilities.

Notes to Financial Statements

Balancing Pool

Provisions for Onerous Contracts (Other Long-Term Obligations)

A provision for an onerous contract is recognized when the unavoidable cost of meeting the obligations under the contract exceed the economic benefits expected to be derived from the contract. The provision is measured at the lower of the expected cost of terminating the contract and the expected cost of continuing performance under the contract. The Balancing Pool recognized onerous contract provisions in 2018 for the following PPAs: Sheerness, Keephills and Genesee. The provisions for onerous contracts have been classified as part of other long-term obligations on the Statements of Financial Position in the comparative period.

The discount rate used to measure these liabilities is based upon the risk-free rate. Where the Balancing Pool expects some or all of the provision will be reimbursed by a third party, the expense relating to any provision is presented in the Statement of Income and Comprehensive Income net of the reimbursement. The expected reimbursement receivable is recognized as an asset if it is virtually certain that the reimbursement will be received and the amount receivable can be measured reliably.

Other Provisions (Trade Payables and Accrued Liabilities)

Provisions for obligations are recognized when the Balancing Pool has a present legal or constructive obligation as a result of past events, it is probable that an outflow of resources will be required to settle the obligation and the amount can be reliably estimated. Provisions are not recognized for future operating losses.

Provisions are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the end of the reporting period. The discount rate used to determine the present value is a risk-free discount rate that reflects current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognized as finance expense.

On transition to IFRS 16 on January 1, 2019, the onerous contract provision was re-measured to reflect the actual PPA capacity payments for 2019 and the revised estimate for 2020 PPA capacity payments.

The monthly PPA losses will no longer be applied to the onerous contract provision as the provision has been reduced to zero and recorded as a right-of-use asset and a lease liability on adoption of IFRS 16.

Revenues and expense of the PPAs, except for the lease payments will be recorded on the statement of income (loss). The monthly lease payments of the PPA will be applied to the lease liability.

Power Purchase Arrangement and Related Finance Lease Liability

The PPAs transfer to the Balancing Pool substantially all the benefits and some of the risks of ownership and therefore the arrangements are classified as finance leases, with the Corporation as the lessee. A lease is considered to be a finance lease when the terms of the lease transfer substantially all of the risks and rewards incidental to ownership of the leased assets to the lessee. Finance leases are capitalized at the lease's commencement at the fair value of the leased property.

On adoption of IFRS 16, *Leases*, lease liabilities and right-of-use assets were established for the PPAs.

Notes to Financial Statements

Balancing Pool

4. Significant Accounting Judgments, Estimates and Assumptions

The timely preparation of the financial statements requires that management make estimates and assumptions and use judgment regarding the reported value of assets and liabilities, disclosures of contingent assets and liabilities at the date of the financial statements and the amounts of revenues and expenses reported for the year. Such estimates reflect management's best estimate of future events as of the date of the financial statements. These financial statements have, in management's opinion, been properly prepared using careful judgment within reasonable limits of materiality and within the framework of the significant accounting policies summarized below. Accordingly, actual results will differ from estimated amounts as future confirming events occur.

Critical Judgments in Applying Accounting Policies

Management has made critical judgments in applying accounting policies, including when:

- concluding that the consumer collection (allocation) is accounted for as revenue (refund of revenue) from a contract with a customer (Note 1, 15);
- forecasting future power prices and capacity factors; and
- estimating the amount of the liability related to AUC Proceeding 790 ("retroactive line loss adjustment") (Note 16).

These critical judgements have been made in the process of applying accounting policies and have a significant effect on the amounts recognized in the financial statements.

Key Sources of Estimation Uncertainty

Since the determination of certain assets, liabilities, revenues and expenses is dependent upon and determined by future events, the preparation of these financial statements requires the use of estimates and assumptions. These estimates and assumptions have been made using careful judgment. Actual results are likely to differ from the results derived using these estimates. The following are items that have been derived using key assumptions concerning future outcomes and subject to several other key sources of estimation uncertainty. As a consequence, there is a significant risk of a material adjustment to the carrying amount of assets and liabilities within the next financial year:

- Hydro Power Purchase Arrangement (Note 8 b i)
- Intangible assets (Note 7)
- Reclamation and abandonment provision (Note 12)
- Other long-term obligations (Note 14)
- Accrued liabilities, Retroactive line loss adjustment (Note 11)

In the opinion of management, these financial statements have been properly prepared in accordance with IFRS, within reasonable limits of materiality and the framework of the significant accounting policies summarized in Note 3 to the financial statements.

Notes to Financial Statements

Balancing Pool

5. Trade and Other Receivables

(in thousands of dollars)	December 31, 2019	December 31, 2018
Trade receivables	76,950	198,634
Other receivables	8,700	2,616
	85,650	201,250

6. Long-term receivables

(in thousands of dollars)	December 31, 2019	December 31, 2018
Opening balance, long-term receivable	3,941	5,882
Accretion	39	59
Cash received from PPA settlement	(2,000)	(2,000)
Closing balance, long-term receivable	1,980	3,941
Less: Current portion	(1,980)	(1,980)
	-	1,961

$2.0 million in cash was received in December 2018 and December 2019 in relation to the PPA settlements reached in November 2016.

7. Intangible Assets

(in thousands of dollars)	December 31, 2019	December 31, 2018
Opening balance, emission credits	26,899	153,120
Additions from purchases	64,879	33,533
Additions from PPA settlement received	-	5,000
Retirement of emission credits	(89,278)	(164,754)
Closing balance, emission credits	2,500	26,899

At December 31, 2019, the Balancing Pool had $2.5 million (2018 – $26.9 million) in emission credits, which can be used to offset environmental compliance obligations associated with the PPAs. In 2019, the Balancing Pool purchased $64.9 million (2018 – $33.5 million) in emission credits. Over the course of 2019, $89.3 million (2018 – $164.8 million) in emission credits were retired to satisfy PPA environmental compliance obligations for the fourth quarter 2018 and the first three quarters of 2019.

No impairments of emission credits were recognized during the year ended December 31, 2019 (2018 – $nil).

Notes to Financial Statements

Balancing Pool

8. a) Risk Management Overview

The Balancing Pool's activities expose the Corporation to a variety of financial risks: market risk (including fluctuating market prices, plant availability, risks associated with PPA payments [receipts] and interest rate risk), credit risk and liquidity risk. The Balancing Pool has developed Risk Management and Credit Policies that define the organization's tolerance for risk and set out procedures for quantifying and monitoring exposures. Exposures and compliance with the policies are regularly monitored by management, the Audit and Finance Committee and the Board.

Market Risk – Power

i) Fluctuating Market Prices: Changes in the market price for electricity and ancillary services affect the amount of revenues that the Balancing Pool receives from the thermal and Hydro PPAs. Electricity prices are volatile, and are affected by supply and demand, which in turn are influenced by fuel costs (e.g. natural gas prices), weather patterns, plant availability and power imports or exports. Economic activity is a key contributor to market price risk as it relates to the demand for electricity. Market price risk may be managed through the use of financial forward sale contracts for electricity.

ii) Plant Availability: Changes in plant availability can impact the expected level of generation output and associated revenues and expenses of the Balancing Pool. According to the terms of the PPA, the Balancing Pool is entitled to availability incentive payments when the plant generates at levels below target availability. If the plant generates above the target availability, the Balancing Pool is required to make payments to the Owner of the plant. The Balancing Pool is not entitled to availability incentive payments during an event of force majeure.

iii) Capacity Payment: The Balancing Pool is exposed to interest rate risk in relation to the annual capacity payments.

Market Risk

i) Interest Rate Risk: The Balancing Pool is exposed to interest rate risk on the related party loan. There is the possibility that the value of the related party loan will change due to fluctuations in market interest rates.

ii) Counterparty Credit Risk: The Balancing Pool is exposed to counterparty credit risk. In the event of a default on payments from counterparties to the Hydro PPA, a financial loss may be experienced by the Balancing Pool. Credit risk is managed in accordance with the Credit Policy which requires that all counterparties maintain investment-grade status level. Status of counterparty credit is regularly monitored by management and the Audit and Finance Committee. The Balancing Pool has minimal credit risk related to its receivables and cash as they consist primarily of amounts owing from the AESO, a government-related entity. The Balancing Pool does not consider any of the trade or long-term accounts receivable to be impaired or past due.

iii) Liquidity Risk: Liquidity risk is the risk that the Balancing Pool will not be able to meet its financial obligations as they fall due. To manage this risk, management forecasts cash flows for a period of 12 months and beyond and will adjust the consumer collection according to the *Balancing Pool Regulation* and borrow from the Government of Alberta. The changes to the EUA, enacted in December of 2016, provide the Balancing Pool with the capacity to borrow from the Government of Alberta (Note 18).

Notes to Financial Statements

Balancing Pool

The following table analyzes the Balancing Pool's financial and other liabilities into relevant maturity groupings based on the remaining period from the period end date to the contract maturity date.

	1 year	2 – 5 years	Total
(in thousands of dollars)	December 31, 2019		
Trade payables	61,931	-	61,931
Other accrued liabilities	150,593	-	150,593
Related party loan – principal	197,393	498,476	695,869
Related party loan – interest	5,372	4,743	10,115
Reclamation and abandonment	676	32,183	32,859
Lease liability	410,025	91	410,116
Total	825,990	535,493	1,361,483
(in thousands of dollars)	December 31, 2018		
Trade payables	128,258	-	128,258
Other accrued liabilities	177,099	-	177,099
Small Power Producer Contracts	444	-	444
Related party loan – principal	410,295	498,355	908,650
Related party loan – interest	2,107	4,538	6,645
Reclamation and abandonment	1,680	22,482	24,162
Other long-term obligations	79,723	164,760	244,483
Total	799,606	690,135	1,489,741

8. b) Analysis of Financial Instruments

i) Hydro Power Purchase Arrangement

The Balancing Pool is the counterparty to the Hydro PPA, a financial arrangement recorded as an asset at the present value of estimated amounts to be received, net of Hydro PPA obligations, over the remaining term of the Hydro PPA.

The notional production of electricity under the Hydro PPA is 1,626 gigawatt hours ("GWh") per annum for 2020. Hydro PPA receipts are settled on a monthly basis.

The remaining term of the Hydro PPA is one year to December 31, 2020. At December 31, 2019, the net present value of the Hydro PPA was estimated at $110.7 million (2018 – $135.3 million). Key assumptions in this valuation are a monthly discount rate of 0.9% for an annual rate of 11.3% (2018 – annual rate of 11.5%) and an estimated forecast average market electricity price of $54.98/megawatt hour ("MWh") for 2020 (2018 – $55.28/MWh for 2019 and $49.19/MWh for 2020).

Under the terms of the Hydro PPA, the Balancing Pool has remitted to TransAlta Corporation ("TransAlta") charges related to line losses for the previous 19 years. The AUC, in its decision released on December 2017, ruled that the methodology for which line losses is calculated will be revised, dating back to 2006. The revised methodology will result in a credit for line loss charges previously paid by the Balancing Pool to TransAlta. Under the terms of the PPA, TransAlta will be required to pass the line loss credit onto the Balancing Pool. An estimate of $33.3 million has been included in the value of the Hydro PPA. The estimate is subject to measurement uncertainty.

Notes to Financial Statements

Balancing Pool

Hydro Power Purchase Arrangement *(in thousands of dollars)*	2019	2018
Hydro Power Purchase Arrangement, opening balance	135,340	177,816
Accretion and current year change	(28,995)	48,959
Line loss credit	32,191	-
Net cash receipts	(77,016)	(86,734)
Revaluation of Hydro Power Purchase Arrangement asset	49,147	(4,701)
Hydro Power Purchase Arrangement, closing balance	110,667	135,340
Less: Current portion receivable	(110,667)	(89,343)
	-	45,997

The estimated value of this asset varies based on the assumptions used and there is a high degree of measurement uncertainty. The following table summarizes the impact on the Hydro PPA value when the estimated forecast average market price is increased or decreased by 10% and the discount rate is increased or decreased by 1%, all other inputs being constant.

	Impact of change to price volatility		Impact of change to discount rate	
(in thousands of dollars)	Increase price by 10%	Decrease price by 10%	Increase discount rate by 1%	Decrease discount rate by 1%
Change in fair value as at December 31, 2019	14,767	(14,767)	(686)	697
Change in fair value as at December 31, 2018	25,685	(25,577)	(1,690)	1,729

ii) Small Power Producer Contract

On February 15, 2019, the last small power producer contract with a total allocated capacity of 10 MW (2018 – one contract with capacity of 10 MW) and a contract price of $79.70/MWh expired. Under this contract, the price that the small power producer received from the counterparty utility company was fixed. If the market price is below the contract price, the Balancing Pool must pay the difference to the utility company. If the market price exceeds the contract price, the utility company must pay the difference to the Balancing Pool.

Small Power Producer Contract *(in thousands of dollars)*	2019	2018
Small power producer contract, opening balance	(444)	(3,722)
Accretion and current year change	393	1,090
Net cash payments	51	2,271
Revaluation of Small Power Producer Contract	-	(83)
Small Power Producer Contracts, closing balance	-	(444)
Less: Current portion	-	444
	-	-

Notes to Financial Statements

Balancing Pool

8. c) Fair Value Hierarchy

Financial instruments carried at fair value are categorized as follows:

(in thousands of dollars)	Quoted prices in active markets for identical assets Level 1	Significant other observable inputs Level 2	Significant unobservable inputs Level 3	Total
		December 31, 2019		
Assets				
Cash and cash equivalents	96,037	-	-	96,037
Hydro Power Purchase Arrangement	-	-	110,667	110,667
	96,037	-	110,667	206,704
Liabilities				
	-	-	-	-
	96,037	-	110,667	206,704
		December 31, 2018		
Assets				
Cash and cash equivalents	175,851	-	-	175,851
Hydro Power Purchase Arrangement	-	-	135,340	135,340
	175,851	-	135,340	311,191
Liabilities				
Small Power Producer Contracts	-	-	444	444
	-	-	444	444
	175,851	-	134,896	310,747

i) Level 1

Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities.

ii) Level 2

Assets and liabilities in Level 2 include valuations using inputs other than Level 1 quoted prices for which all significant inputs are observable, either directly or indirectly. Fair values for fixed income investments are determined using quoted market prices in active markets.

iii) Level 3

Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. Changes in valuation methods may result in transfers into or out of an assigned level. There were no transfers between Level 3 and Level 2. The Hydro PPA and Small Power Producer Contract values are determined using discounted cash flow forecast methods and supported by observable market prices when available. Methodologies have been developed to determine the fair value for these contracts based on forecast of the hourly electricity market price in Alberta's hourly market using proprietary third-party merit order dispatch model. Management reviews the discounted cash flow forecasts on an annual basis. The changes in value, key assumptions and sensitivities in Level 3 instruments for the years ended December 31, 2019 and 2018 are disclosed in Note 8 b i) and in Note 8 b ii).

Notes to Financial Statements

Balancing Pool

9. Right-of-Use Assets

(in thousands of dollars)	Genesee PPA	Keephills PPA	Sheerness PPA	Office Lease	Total
At January 1, 2019	271,217	152,942	174,846	393	599,398
Amortization and depreciation	(135,608)	(76,471)	(87,423)	(152)	(299,654)
Reassessment of lease liability	(6,506)	(1,471)	(1,757)	-	(9,734)
At December 31, 2019	129,103	75,000	85,666	241	290,010
Less: Current portion	(129,103)	(75,000)	(85,666)	(152)	(289,921)
	-	-	-	89	89

On adoption of IFRS 16 effective January 1, 2019, right-of-use assets in the amount of $841.4 million were established for the three PPAs and $0.4 million for the office lease. Given the onerous contract status of the three PPAs, the right-of-use assets for the three PPAs were impaired on transition to IFRS 16 by $242.4 million, leaving a balance of $599.0 million to be amortized over the remaining two-year term. Over the course of the year, $299.7 million in amortization and depreciation was recorded. At December 31, 2019, a reassessment of the lease liability of $9.7 million was recorded due to a change in the monthly lease payments for the PPAs. This reduction to the liability has been applied to the right-of-use assets for the PPAs.

10. Finance Expense

(in thousands of dollars)	2019	2018
Interest expense – related party loan	18,948	16,086
Interest expense – lease liability	15,991	-
Accretion expense – reclamation and abandonment	452	331
	35,391	16,417

11. Trade Payable and Other Accrued Liabilities

(in thousands of dollars)	2019	2018
Trade payables	61,931	128,258
Accrued liabilities – Greenhouse gas obligation	66,891	82,046
Accrued liabilities – PILOT refunds	-	28,047
Accrued liabilities – Line loss provision (Note 16)	68,440	45,536
Accrued liabilities – Other	15,262	21,470
	212,524	305,357

On September 30, 2019 Alberta Tax and Revenue Administration reached a settlement with a municipal entity subject to PILOT on all remaining disputed matters. As a result of the settlement, the Balancing Pool refunded $22.2 million to the municipal entity. The Balancing Pool had previously accrued $28.0 million related to the remaining matters disputed, resulting in a recovery of $5.8 million.

Notes to Financial Statements

Balancing Pool

12. Reclamation and Abandonment Provision

(in thousands of dollars)	H.R. Milner Generating Station	Isolated Generation Sites	Sundance A Generating Station	Total
At January 1, 2018	13,215	6,728	1,695	21,638
Net increase (decrease) in liability	(69)	379	10,216	10,526
Liabilities paid in year	(2,879)	(5,454)	-	(8,333)
Accretion expense	202	103	26	331
At December 31, 2018	10,469	1,756	11,937	24,162
Less: Current portion	-	(1,680)	-	(1,680)
	10,469	76	11,937	22,482
At January 1, 2019	10,469	1,756	11,937	24,162
Net increase (decrease) in liability	(1,459)	2,190	9,813	10,544
Liabilities paid in year	(298)	(2,001)	-	(2,299)
Accretion expense	196	33	223	452
At December 31, 2019	8,908	1,978	21,973	32,859
Less: Current portion	(279)	(397)	-	(676)
	8,629	1,581	21,973	32,183

12. a) Decommissioning Costs of H.R. Milner Generating Station

Under the Asset Sale Agreement for the H.R. Milner generating station between the Balancing Pool and ATCO Power Ltd ("ATCO"), which was executed in 2001, the Balancing Pool assumed the liability for the costs of decommissioning the station at the end of operations. When the asset was subsequently re-sold to Milner Power Limited Partnership in 2004, the Balancing Pool retained the liability for decommissioning the generating station. In 2011, a bilateral agreement was reached with Milner Power Limited Partnership wherein the Balancing Pool's exposure to future decommissioning costs was capped at $15.0 million. As at December 31, 2019, a total of $4.2 million has been paid for decommissioning the Milner generating site, leaving a balance of $10.8 million remaining. A further $0.3 million is expected to be incurred in 2020. These costs have been discounted at the risk-free rate of 1.7% (2018 – 1.9%). At December 31, 2019, the provision was decreased by $1.5 million (2018 – $0.7 million decrease) to reflect a change in the estimated payment date of December 31, 2030. Expenditures of $0.3 million were incurred in 2019 (2018 – $2.9 million).

12. b) Isolated Generation Sites

Under the *Isolated Generating Units and Customer Choice Regulations of the EUA*, the Balancing Pool is liable for the reclamation and abandonment costs associated with various Isolated Generation sites. Expenditures of $2.0 million (2018 – $5.5 million) were incurred in 2019. Pursuant to the Negotiated Settlement Agreements approved by the AUC, the ultimate payment of these costs must be reviewed and approved by the Remediation Review Committee. The Remediation Review Committee was established to monitor, verify and approve all costs associated with the reclamation and abandonment of the Isolated Generation sites. Estimated reclamation and abandonment costs have been discounted at 1.7% (2018 – 1.9%). The provision is based upon management's best estimate and the timing of the costs. Management anticipates the Isolated Generation projects will conclude at the end of 2021. At December 31, 2019, an increase of $2.2 million (2018 – $0.4 million increase) was recorded to reflect a change in estimation to complete the project.

Notes to Financial Statements

Balancing Pool

12. c) Decommissioning Costs of PPAs

Pursuant to Section 5 of the *Power Purchase Arrangements Regulation*, the Owner of a generating unit who applies to the AUC to decommission a unit within one year of the termination or expiration of the PPA is entitled to receive funding from the Balancing Pool. The amount of funding provided by the Balancing Pool is the amount by which the decommissioning costs (net of salvage) exceed the decommissioning amounts the Owner collected from related consumers before January 1, 2001 and subsequently through the related PPA. Subject to AUC approval, Owners are eligible to collect this shortfall provided that the unit has ceased generating electricity. Section 5 of the *Power Purchase Arrangements Regulation* does not apply after December 31, 2018.

In December 31, 2019, the Balancing Pool recorded a $9.8 million increase (2018 – $10.2 million increase) to the provision for decommissioning the Sundance A unit. In December 2018, TransAlta submitted an application to the AUC to decommission Sundance A. The provision for Sundance A is based upon management's best estimate of decommissioning costs. Estimated decommissioning costs were discounted at 1.7% (2018 – 1.9%). The AUC will determine the amount owed to TransAlta. See also Note 16.

13. Lease Liability

(in thousands of dollars)	Genesee PPA	Keephills PPA	Sheerness PPA	Office Lease	Total
At January 1, 2019	340,830	225,640	274,886	393	841,749
Finance expense	6,476	4,287	5,222	6	15,991
Lease payments	(175,150)	(116,360)	(146,226)	(155)	(437,891)
Reassessment of lease liability	(6,505)	(1,471)	(1,757)	-	(9,733)
At December 31, 2019	165,651	112,096	132,125	244	410,116
Less: Current portion	(165,651)	(112,096)	(132,125)	(153)	(410,025)
	-	-	-	91	91

The Balancing Pool has recognized lease liabilities in relation to the Genesee, Keephills and Sheerness PPAs and the office lease. The lease liabilities have been discounted using a rate of 1.9% effective January 1, 2019.

At December 31, 2019, a reassessment of the lease liability of $9.7 million was recorded due to a change in the monthly lease payments for the PPAs. The lease payment change was a result of a change to indices with respect to labour and material costs.

The long-term portion of the lease liability represents the office lease which expires on June 30, 2021.

Notes to Financial Statements

Balancing Pool

14. Other Long-Term Obligations

(in thousands of dollars)	Genesee	Battle River 5	Sundance B	Sundance C	Keephills	Sheerness	Total
At January 1, 2018	147,947	113,998	95,961	108,658	69,584	121,573	657,721
Net increase (decrease) in liability	(2,820)	1,296	6,809	13,946	53,055	55,377	127,663
Termination payment	-	(61,680)	(71,604)	(85,349)	-	-	(218,633)
Losses	(72,980)	(53,614)	(31,166)	(37,255)	(49,695)	(77,558)	(322,268)
At December 31, 2018	72,147	-	-	-	72,944	99,392	244,483
Less: Current portion	(15,453)	-	-	-	(25,104)	(39,166)	(79,723)
	56,694	-	-	-	47,840	60,226	164,760
At January 1, 2019	72,147	-	-	-	72,944	99,392	244,483
Adoption of IFRS 16, Leases	(72,147)	-	-	-	(72,944)	(99,392)	(244,483)
At December 31, 2019	-	-	-	-	-	-	-

On January 1, 2019 the Balancing Pool adopted IFRS 16, *Leases*. The onerous contract provision established for the PPAs transitioned to the new leasing standard. The provision was drawn down to zero and a lease liability and right-of-use assets were established for the three remaining PPAs. The onerous contract provision was re-measured to reflect actual 2019 capacity payments and revised 2020 capacity payments prior to transition resulting in a recovery of $2.1 million.

Pursuant to Section 96 of the EUA, following Buyer-initiated terminations in 2016, the Battle River 5 PPA, Sundance A, Sundance B, Sundance C, Sheerness and Keephills PPAs were transferred to the Balancing Pool. While the Balancing Pool holds the PPAs, it assumes responsibility for ongoing capacity payments and other PPA-related costs and is responsible for selling the output into the wholesale power market.

The Balancing Pool terminated the Sundance B and C PPAs effective April 1, 2018 and the Battle River 5 PPA effective October 1, 2018. The Sundance A PPA expired on December 31, 2017.

Based on the estimated forecast average electricity market price of $55.28/MWh for 2019 and $49.19/MWh for 2020 as at December 31, 2018, the unavoidable costs of meeting the obligations under the PPAs were expected to exceed the economic benefits derived from the PPAs. As a result, for the 2018 year ended, onerous contract provisions were recognized and measured at the lower of the present value of continuing the PPAs and the expected costs of terminating them. Cost of termination included the estimated net costs of holding the PPAs over the minimum six-month notice period preceding such termination plus a termination payment. For purposes of measuring the onerous contract provision under IFRS as at December 31, 2019, the minimum six-month notice period was estimated to commence on January 1, 2019 for the Genesee, Keephills and Sheerness PPAs. The termination payment represents the net book value of the units which is estimated at $933.5 million for Genesee, Keephills and Sheerness. The estimated future costs for the three PPAs were discounted at 1.9%.

Future cash flow requirements may include operating losses where the price in Alberta's hourly wholesale electricity market is less than the operating costs over the period of 2019 and 2020. It is expected operating costs would include amounts associated with the *Carbon Competitiveness Incentive Regulation* for all of the PPAs for the period of 2019 and 2020. Revenue is also dependant on generating capacity factors of the different PPAs, which can vary for each PPA.

Notes to Financial Statements

Balancing Pool

15. Capital Management

The Balancing Pool's objective when managing capital is to operate as per the requirements of the EUA, which requires the Balancing Pool to operate with no profit or loss and no share capital and to forecast its revenues, expenses, and cash flows. Any excess or shortfall of funds in the accounts is to be allocated to, or provided by, electricity consumers over time. During 2016, the Alberta Government enacted amendments to the *Balancing Pool Regulation* that defined the method by which the Balancing Pool would calculate the amounts to be allocated to, or provided by, electricity consumers through to 2030. In January 2017, the Balancing Pool signed a loan agreement with the Government of Alberta. The loan agreement was put in place through Alberta Treasury Board and Finance to fund operating losses of the Balancing Pool, including obligations associated with the terminated PPAs.

A reconciliation of the opening and closing Balancing Pool deferral account is provided below.

Balancing Pool Deferral Account *(in thousands of dollars)*	2019	2018
Deferral account, beginning of year	(946,456)	(1,280,998)
Change to the Balancing Pool deferral account	171,831	334,542
Deferral account, end of year	(774,625)	(946,456)

In December 2018, the Board of Directors approved a 2019 consumer collection of $2.90/MWh for a total collection from electricity consumers of $173.0 million in accordance with the *Balancing Pool Regulation*. In October 2019, the Board of Directors approved a 2020 consumer collection of $2.50/MWh for an estimated total collection from electricity consumers of $160.0 million in accordance with the *Balancing Pool Regulation*.

16. Contingencies and Commitments

Reclamation and Abandonment

TransAlta has submitted an application to the AUC to decommission Sundance A and is seeking $41.4 million in funding from the Balancing Pool. The Balancing Pool disagrees with several aspects of the application. The Balancing Pool has a provision of $22.0 million to decommission Sundance A. The final amount due will be determined by the AUC.

Retroactive Line Loss Adjustment (AUC Proceeding 790)

Line loss factors form part of transmission charges that are paid by generators in Alberta. The Balancing Pool is exposed to retroactive line loss adjustments for certain PPAs.

In January 2015, the AUC determined that it has the jurisdiction and authority to retroactively adjust the line loss factors and the associated methodology dating back to 2006. On December 19, 2018, the Court of Appeal upheld the AUC's determination. In December 2017, the AUC ruled on the methodology to be used to calculate retroactive line loss adjustments. The AUC also ruled that the original system transmission service contract holders will be responsible for the retroactive line loss adjustments. The Balancing Pool and the AESO will net settle line loss amounts associated with the PPA units that were under system transmission service contracts held by the Balancing Pool during the relevant time period. The Balancing Pool will also net settle line loss amounts with certain PPA counterparties that held system transmission service contracts for certain PPA units during the relevant time period.

The various matters approved by the AUC regarding the retroactive line loss adjustments were the subject of permission to appeal applications filed with the Alberta Court of Appeal, including the retroactive nature of the adjustments and prospective line loss factors used to calculate the adjustment. In rulings dated April 8, 2019 and June 3, 2019, the Alberta Court of Appeal denied all applications for permission to appeal in regards to these matters.

The Balancing Pool will incur additional charges as a result of the retroactive adjustments to line loss factors in relation to the various PPAs. An estimated provision in the amount of $68.4 million (2018 – $45.5 million) has been recorded in trade payable and other accrued liabilities for the retroactive line loss adjustment. The estimate has been prepared using the methodology approved by the AUC. The final calculations have not been published and therefore the Balancing Pool's estimates are subject to measurement uncertainty in these financial statements.

Legal Claim

On June 12, 2019, the Balancing Pool received a statement of claim from a power producer seeking $17.5 million in damages from the Balancing Pool. The Balancing Pool has filed a statement of defence and will vigorously defend its position. The Balancing Pool is of the opinion the statement of claim is without merit. Furthermore, Section 92 of the *Electric Utilities Act* provides the Balancing Pool with strong liability protection for such claims. As at December 31, 2019, no contingent liability has been recorded, as the Balancing Pool does not expect a material outflow.

Notes to Financial Statements

Balancing Pool

17. Cost of Sales

(in thousands of dollars)	2019	2018
Cost of Power Purchase Arrangements and power marketing	590,151	1,240,067
Losses on PPAs recorded against other long-term obligations	-	(322,268)
Gain on the retirement of emission credits	(17,845)	(74,610)
Amortization and depreciation on right-of-use assets	299,660	23
	871,966	843,212

Included as a reduction to cost of sales is a gain on the retirement of emission credits in the amount of $17.8 million (2018 – $74.6 million). The gain on emission credits is a result of procuring emission credits at a price lower than the Climate Change Emission Management Fund rate of $30 per tonne.

On adoption of IFRS 16, the portion of the capacity payment that is based upon indices and rates (capital recovery charge, indexed fuel charge and indexed operational and maintenance charge) has been classified as the fixed lease payment. The fixed lease payment portion of the total capacity payment is used to establish the lease liability. As the capacity payments are invoiced by the plant owner, the fixed lease payment portion of the total capacity payment is recorded against the lease liability and not recorded through the income statement. The balance of the capacity payment is expensed through the income statement.

On adoption of IFRS 16, the PPA losses are no longer reclassified and applied to the PPA provision as the provision has been drawn down to nil.

The Balancing Pool terminated the Sundance B and C PPAs effective April 1, 2018. A termination payment of $71.6 million and $85.3 million, respectively, was issued to TransAlta. The termination payment issued to TransAlta represents the remaining closing net book value of the generating units. TransAlta disputed the amount of the termination payment with respect to the Sundance B and C PPAs and on August 23, 2019 an arbitration panel issued its decision regarding termination payment dispute with TransAlta. The arbitration panel awarded TransAlta an additional termination payment of $57.2 million, including interest. The payment was issued to TransAlta on August 29, 2019.

The Battle River 5 PPA was terminated effective October 1, 2018. A termination payment of $61.7 million was issued to Alberta Power (2000) Ltd. following which Alberta Power (2000) Ltd. advised it intended to dispute the Battle River 5 PPA termination payment. In November 2019, the Balancing Pool reached a negotiated settlement with Alberta Power (2000) Ltd. and issued an additional termination payment of $5.5 million.

Notes to Financial Statements

Balancing Pool

18. Related Party Transactions

Key Management Compensation

Key management includes members of the Board of the Balancing Pool and the Chief Executive Officer. The compensation paid or payable to key management for services is shown below.

Key Management Compensation *(in thousands of dollars)*	2019	2018
Salaries, other short-term employee benefits and severance	822	627
Total	822	627

Government-Related Entity

The Balancing Pool considers itself to be a government-related entity as defined by IAS 24 – *Related Party Disclosures* and applies the exemption from the disclosure requirements of Paragraph 18 of IAS 24 – *Related Party Disclosures*. The members of the Board are appointed by the Minister of Energy of the Government of Alberta. Effective January 1, 2017, the financial information of the Balancing Pool is being consolidated by the Ministry of Energy.

In January 2017, the Balancing Pool signed a loan agreement with the Government of Alberta. The loan agreement was put in place through Alberta Treasury Board and Finance to fund operating losses of the Balancing Pool, including obligations associated with the terminated PPAs.

(in thousands of dollars)	Interest Rate	December 31, 2019
Long-term note due on Sep. 13, 2023	2.65%	503,219
Short-term discount note due on Jan. 02, 2020	1.97%	127,986
Short-term discount note due on Feb. 24, 2020	1.97%	74,779
		705,984
Less: Current portion		(202,765)
		503,219
	Interest Rate	**December 31, 2018**
Long-term note due on Sep. 13, 2023	2.65%	502,893
Short-term discount note due on Jan. 04, 2019	1.96%	90,980
Short-term discount note due on Jan. 30, 2019	1.96%	196,682
Short-term discount note due on Feb. 06, 2019	1.43%	124,740
		915,295
Less: Current portion		(412,402)
		502,893

Notes to Financial Statements

Balancing Pool

At December 31, 2019, the Balancing Pool had $706.0 million (2018 – $915.3 million) in short-term discount and long-term notes issued to the Government of Alberta, including accrued interest of $5.6 million (2018 – $7.1 million). Fair value of the loan is the same as the amortized cost of borrowing. During 2019, interest of $20.0 million was paid on the related party loan (2018 – $16.0 million).

Directed by the Minister of Energy, the Balancing Pool is mandated to make payments to the Office of the Utilities Consumer Advocate ("UCA") to cover 80% of their annual operating costs and to the Transmission Facilities Cost Monitoring Committee ("TFCMC") to cover 100% of their annual costs.

In 2019, the Balancing Pool expensed $4.6 million (2018 – $5.2 million) for the UCA and $0.1 million (2018 – $0.7 million recovery) for the TFCMC.

The Balancing Pool also considers the AESO a government-related entity. The EUA requires the Balancing Pool to forecast its revenues and expenses with any excess or shortfall of funds in the accounts to be allocated to, or provided by, electricity consumers over time. Pursuant to the EUA, the AESO facilitates the collection or distribution of any excess or shortfall through an annualized amount included in the AESO's transmission tariff. In 2019, the Balancing Pool collected $173.0 million (2018 – $189.2 million) from electricity consumers through the AESO's transmission tariff.

The AESO also operates the spot market in Alberta and remits payment for electricity sold in the spot market. In 2019 the Balancing Pool received $875.2 million (2018 – $965.2 million) related to the sale of electricity for the PPAs.

Notes to Financial Statements

Balancing Pool

19. Subsequent Events

Related Party Transactions

On January 2, 2020 and February 24, 2020 the maturing related-party short-term notes were re-financed with the terms note below.

(in thousands of dollars)	Interest Rate	Amount re-financed
Short-term discount note due on May 1, 2020	1.81%	128,000
Short-term discount note due on June 23, 2020	1.69%	75,000

Emission Credits

On March 17, 2020, the Balancing Pool purchased 459,000 tonnes of emission credits for the amount of $11.9 million. The emission credits were retired to satisfy the fourth quarter 2019 *Carbon Competiveness Incentive Regulation* obligation of the PPAs.

Novel Coronavirus (“COVID-19”)

With the outbreak of COVID-19, the Balancing Pool has deployed its Business Continuity Plan in order to protect the health and safety of Balancing Pool personnel and to ensure the Balancing Pool continues to execute its mandate. All Balancing Pool personnel have been working remotely since March 16, 2020 and will continue to do so for an indefinite period of time. The Balancing Pool does not anticipate a significant impact to daily operations as a result of COVID-19.

The spread of COVID-19 in Alberta and the restrictions imposed by various levels of government may impact the demand for electricity, which may result in lower future Alberta power prices. Lower power prices will reduce Sale of Electricity revenue from the thermal PPAs and the Hydro PPA. Reduced revenues may result in the Balancing Pool drawing on funds available through the Provincial government loan to satisfy its obligations.

The Corporation has determined that these events are non-adjusting subsequent events. Accordingly, the financial position and results of operations as of and for the year ended December 31, 2019, have not been adjusted to reflect their impact.

The Provincial government has announced that residential, farm, and small commercial businesses can defer payment of utility bills for 90 days. The impact to the Balancing Pool is uncertain.

Post Closure Stewardship Fund

Financial Statements

For the year ended March 31, 2020

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Auditor General
OF ALBERTA

Independent Auditor's Report

To the Minister of Energy

Report on the Financial Statements

Opinion

I have audited the financial statements of the Post-Closure Stewardship Fund, which comprise the statement of financial position as at March 31, 2020, and the statements of operations, change in net financial assets, and cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In my opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Post-Closure Stewardship Fund as at March 31, 2020, and the results of its operations, its changes in net financial assets, and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Basis for opinion

I conducted my audit in accordance with Canadian generally accepted auditing standards. My responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of my report. I am independent of the Post-Closure Stewardship Fund in accordance with the ethical requirements that are relevant to my audit of the financial statements in Canada, and I have fulfilled my other ethical responsibilities in accordance with these requirements. I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my opinion.

Other information

Management is responsible for the other information. The financial statements of the Post-Closure Stewardship Fund are included in the *Energy Annual Report 2019-2020*. The other information comprises the information included in the *Energy Annual Report 2019-2020* but does not include the financial statements and my auditor's report thereon. The *Energy Annual Report 2019-2020* is expected to be made available to me after the date of this auditor's report.

My opinion on the financial statements does not cover the other information and I do not express any form of assurance conclusion thereon.

In connection with my audit of the financial statements, my responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or my knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work I will perform on this other information, I conclude that there is a material misstatement of this other information, I am required to communicate the matter to those charged with governance.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with Canadian public sector accounting standards, and for such internal control as management determines is necessary to enable the preparation of the financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Post-Closure Stewardship Fund's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless an intention exists to liquidate or to cease operations, or there is no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Post-Closure Stewardship Fund's financial reporting process.

Auditor's responsibilities for the audit of the financial statements

My objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes my opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, I exercise professional judgment and maintain professional skepticism throughout the audit. I also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for my opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Post-Closure Stewardship Fund's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Post-Closure Stewardship Fund's ability to continue as a going concern. If I conclude that a material uncertainty exists, I am required to draw attention in my auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify my opinion. My conclusions are based on the audit evidence obtained up to the date of my auditor's report. However, future events or conditions may cause the Post-Closure Stewardship Fund to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

I communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that I identify during my audit.

[Original signed by W. Doug Wylie FCPA, FCMA, ICD.D]
Auditor General

July 14, 2020
Edmonton, Alberta

Statement of Operations

Post-Closure Stewardship Fund
Year ended March 31, 2020
(in thousands)

	2020		2019
	Budget	Actual	Actual
Revenue			
Injection Levy (Note 3)	$ 230	$ 261	$ 251
Investment Income	-	38	10
Net Operating Results	230	299	261

The accompanying notes are part of these financial statements.

Statement of Financial Position

Post-Closure Stewardship Fund
As at March 31, 2020
(in thousands)

	2020	2019
Assets		
Cash (Note 4)	$ 1,083	$ 779
Accounts Receivable	141	146
Net Assets	**$ 1,224**	**$ 925**
Net Assets at Beginning of Year	$ 925	$ 664
Annual Operating Results	299	261
Net Assets at End of Year	**$ 1,224**	**$ 925**

The accompanying notes are part of these financial statements.

Statement of Change in Net Financial Assets

Post-Closure Stewardship Fund
Year ended March 31, 2020
(in thousands)

	2020				2019	
	Budget		Actual		Actual	
Annual Operating Results	$	250	$	299	$	261
Increase in Net Assets	$	250	$	299	$	261
Net Assets at Beginning of Year		-		925		664
Net Assets at End of Year	**$**	**250**	**$**	**1,224**	**$**	**925**

The accompanying notes are part of these financial statements.

Statement of Cash Flows

Post-Closure Stewardship Fund
Year ended March 31, 2020
(in thousands)

	2020	2019
Operating Transactions		
Net Operating Results	$ 299	$ 261
Decrease (Increase) in Accounts Receivable	5	(18)
Increase in Cash and Cash Equivalents	**$ 304**	**$ 243**
Cash and Cash Equivalents at Beginning of Year	779	536
Cash and Cash Equivalents at End of Year	**$ 1,083**	**$ 779**

The accompanying notes are part of these financial statements.

Notes to Financial Statements

Post-Closure Stewardship Fund
March 31, 2020
(in thousands)

NOTE 1 AUTHORITY & PURPOSE

The Post-Closure Stewardship Fund operates under the Mines and Minerals Act (MMA), chapter M-17.

The MMA provides an option to the Minister to issue a Closure Certificate to an approved operator after the final injection of captured carbon dioxide has been completed and after satisfying the closure period that is to be specified in regulations. There is no liability to the Fund until such a Closure Certificate has been issued.

The Fund was established to address certain long-term liabilities that may arise from approved projects for the injection of captured carbon dioxide into subsurface reservoirs for sequestration subsequent to the issuance of a Closure Certificate.

The Injection Levy rate(s) are set through Ministerial Orders. These rates are reviewed every three years at a minimum, and will be amended if necessary.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES

These financial statements are prepared in accordance with Canadian Public Sector Accounting Standards.

(a) **Basis of Financial Reporting**

Revenues
Revenues are reported on the accrual basis of accounting. The volume of carbon dioxide injected is based upon reported injection provided by the operator. Third party verification on the volume of injection will take place in the month of October, for injection to September 30. The Injection Levy is calculated based on the net present value of estimated future costs arising from the injection.

Financial Assets
Financial assets are assets that could be used to discharge existing liabilities or finance future operations and are not for consumption in the normal course of operations.

NOTE 3 INJECTION LEVY

The Injection Levy is set aside for Post-Closure Care of the injection site. Post-Closure Care occurs after the issuance of the Closure Certificate and includes the continual monitoring costs of the captured carbon dioxide injection sites and any remediation of the sites that may be required.

At March 31, 2020, there is only one approved carbon dioxide injection site. The estimated present value of the future costs for this site, based on modeling of potential requirement under current technology, is $4.7 million. Currently, approximately 20% of the site's capacity has been used. The project is expected to inject for a 25-year period.

As the site remains active and no Closure Certificate has been issued, there is no expectation of any withdrawals from the Fund at this time.

NOTE 4 CASH

Cash is represented by funds held within the Post-Closure Stewardship Fund's Consolidated Cash Investment Trust Fund (CCITF) bank account. The fund earns interest at an effective rate of 1.80% per annum (2019 - Prime less 2.25%).

NOTE 5 APPROVAL OF FINANCIAL STATEMENTS

The Deputy Minister and the Senior Financial Officer approve these financial statements.

Canadian Energy Centre Ltd.

Financial Statements

Period October 9, 2019 to March 31, 2020

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MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The accompanying Canadian Energy Centre Ltd. (CEC) financial statements have been prepared and presented by management, who is responsible for the integrity and fair presentation of the information.

These financial statements are prepared in accordance with Canadian Public Sector Accounting Standards. The financial statements necessarily include certain amounts based on the informed judgments and best estimates of management.

In fulfilling its responsibilities and recognizing the limits inherent in all systems, the CEC has developed and maintained a system of internal control to produce reliable information for reporting requirements. The systems are designed to provide reasonable assurance that CEC transactions are properly authorized, assets are safeguarded from loss and the accounting records are a reliable basis for the preparation of the financial statements.

The Auditor General of Alberta, the CEC's external auditor appointed under the *Auditor General Act*, performed an independent external audit of these financial statements in accordance with Canadian generally accepted auditing standards and has expressed his opinion in the accompanying Independent Auditor's Report.

CEC's board is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. In both the presence and absence of management, the CEC's board meets with the external auditors to discuss the audit, including any findings as to the integrity of financial reporting processes and the adequacy of our systems of internal controls. The external auditors have full and unrestricted access to the CEC's board.

[Original signed by Tom Olsen]

Chief Executive Officer

June 22, 2020

Auditor General
OF ALBERTA

Independent Auditor’s Report

To the Board of Directors of the Canadian Energy Centre Ltd.

Report on the Financial Statements

Opinion

I have audited the financial statements of the Canadian Energy Centre Ltd. (the CEC), which comprise the statement of financial position as at March 31, 2020, and the statements of operations, change in net financial assets, and cash flows for the period then ended, and notes to the financial statements, including a summary of significant accounting policies.

In my opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the CEC as at March 31, 2020, and the results of its operations, its changes in net financial assets, and its cash flows for the period then ended in accordance with Canadian public sector accounting standards.

Basis for opinion

I conducted my audit in accordance with Canadian generally accepted auditing standards. My responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of my report. I am independent of the CEC in accordance with the ethical requirements that are relevant to my audit of the financial statements in Canada, and I have fulfilled my other ethical responsibilities in accordance with these requirements. I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my opinion.

Other information

Management is responsible for the other information. The other information comprises the information included in the *Annual Report*, but does not include the financial statements and my auditor’s report thereon. The *Annual Report* is expected to be made available to me after the date of this auditor’s report.

My opinion on the financial statements does not cover the other information and I do not express any form of assurance conclusion thereon.

In connection with my audit of the financial statements, my responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or my knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work I will perform on this other information, I conclude that there is a material misstatement of this other information, I am required to communicate the matter to those charged with governance.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with Canadian public sector accounting standards, and for such internal control as management determines is necessary to enable the preparation of the financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the CEC’s ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless an intention exists to liquidate or to cease operations, or there is no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the CEC’s financial reporting process.

Auditor's responsibilities for the audit of the financial statements

My objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes my opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, I exercise professional judgment and maintain professional skepticism throughout the audit. I also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for my opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the CEC's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management’s use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the CEC’s ability to continue as a going concern. If I conclude that a material uncertainty exists, I am required to draw attention in my auditor’s report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify my opinion. My conclusions are based on the audit evidence obtained up to the date of my auditor’s report. However, future events or conditions may cause the CEC to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

I communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that I identify during my audit.

[Original signed by W. Doug Wylie FCPA, FCMA, ICD.D]

Auditor General

June 22, 2020

Edmonton, Alberta

Statement of Operations

Canadian Energy Centre Ltd.
For the period October 9, 2019 to March 31, 2020

		2020	
		Budget	**Actual**
Revenues			
	Government transfers		
	Government of Alberta grants	$ 5,000,000	$ 5,000,000
		5,000,000	**5,000,000**
Expenses	**(Schedule 1)**		
	Resource Development and Management	4,882,625	1,971,073
		4,882,625	**1,971,073**
Current period operating surplus		**117,375**	**3,028,927**
Current surplus		**117,375**	**3,028,927**
	Share capital (Note 10)	-	6,800
Accumulated surplus at end of period (Note 9)		**$ 117,375**	**$ 3,035,727**

The accompanying notes and schedules are part of these financial statements

Statement of Financial Position

Canadian Energy Centre Ltd.
As at March 31, 2020

		2020
Financial Assets		
Cash and cash equivalents (Note 5)	$	2,707,258
Accounts receivable (Note 6)		1,068,576
		3,775,834
Liabilities		
Accounts payable and accrued liabilities (Note 8)		771,592
		771,592
Net Financial Assets		**3,004,242**
Non-Financial Assets		
Prepaid expenses		31,485
		31,485
Net Assets		
Accumulated surplus (Note 9)		**3,035,727**
	$	**3,035,727**

Contingent liabilities (Note 11)
Contractual obligations (Note 12)

The accompanying notes and schedules are part of these financial statements

Approved by:

[Original signed by Hon. Sonya Savage]
Member of Board of Directors

Approved by:

[Original signed by Tom Olsen]
Chief Executive Officer

Statement of Change in Net Financial Assets

Canadian Energy Centre Ltd.
For the period October 9, 2019 to March 31, 2020

	2020 Budget	2020 Actual
Current period surplus	$ 117,375	$ 3,028,927
Increase in share capital	-	6,800
Increase in prepaid expenses	-	(31,485)
Increase in net financial assets	**117,375**	**3,004,242**
Net financial assets at beginning of period	-	-
Net financial assets at end of period	**$ 117,375**	**$ 3,004,242**

The accompanying notes and schedules are part of these financial statements

Statement of Cash Flows

Canadian Energy Centre Ltd.
For the period October 9, 2019 to March 31, 2020

	2020
Operating transactions	
Current surplus	$ 3,028,927
Increase in accounts receivable	(1,068,576)
Increase in prepaid expenses	(31,485)
Increase in accounts payable and accrued liabilities	771,592
Cash provided by operating transactions	2,700,458
Financing transactions	
Increase in share capital	6,800
Cash provided by financing transactions	6,800
Increase in cash and cash equivalents	**2,707,258**
Cash and cash equivalents at beginning of period	**-**
Cash and cash equivalents at end of period	**$ 2,707,258**

The accompanying notes and schedules are part of these financial statements

Notes to the Financial Statements

Canadian Energy Centre Ltd.
For the period October 9, 2019 to March 31, 2020

Note 1 AUTHORITY

The Canadian Energy Centre Ltd. (the "Corporation") is a provincial corporation incorporated under the *Business Corporations Act* (Alberta) on October 9, 2019.

The Corporation is wholly owned by Her Majesty the Queen in the Right of Alberta as represented by the Minister of Energy. It is governed by a Board of Directors appointed by the Province. The Board consists of three Cabinet Ministers appointed by Government of Alberta.

The mandate of the Corporation is to promote Canada as the supplier of choice for the world's growing demand for responsibly produced energy.

As a provincial corporation, the Corporation is exempt from income taxes under the *Income Tax Act.*

Comparative figures are not presented as this is the Corporation's first period of operations.

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES

These financial statements are prepared in accordance with Canadian Public Sector Accounting Standards.

(a) Reporting Entity

The financial statements reflect the assets, liabilities, revenues, and expenses of the reporting entity, which is Canadian Energy Centre Ltd. The Corporation is controlled by and fully consolidated in the Ministry of Energy (the ministry), for which the Minister of Energy is accountable. Inter-entity accounts and transactions between the Corporation and any of the entities included in the ministry are eliminated upon consolidation within the ministry's financial information.

(b) Basis of Financial Reporting

Revenues

All revenues are reported on the accrual basis of accounting.

Government Transfers
Transfers from all governments are referred to as government transfers.

Notes to the Financial Statements

Canadian Energy Centre Ltd.
For the period October 9, 2019 to March 31, 2020

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (Cont'd)

(b) Basis of Financial Reporting (Cont'd)

Government transfers and the associated externally restricted investment income are recognized as deferred capital contributions or deferred revenue if the eligibility criteria for use of the transfer, or the stipulations together with the Corporation's actions and communications as to the use of the transfer, create a liability. These transfers are recognized as revenue as the stipulations are met and, when applicable, the Corporation complies with its communicated use of the transfer.

All other government transfers, without stipulations for use of the transfer, are recognized as revenue when the transfer is authorized, and the Corporation meets the eligibility criteria (if any).

Expenses

Expenses are reported on an accrual basis. The cost of all goods consumed and services received during the period are expensed.

Valuation of Financial Assets and Liabilities

The Corporation's financial assets and liabilities are generally measured as follows:

Financial Statement Component	Measurement
Cash and cash equivalents	Cost
Accounts receivable	Lower of cost or net recoverable value
Accounts payable and accrued liabilities	Cost

The Corporation does not have any financial instruments classified in the fair value category and does not hold derivative contracts. Therefore, these statements do not present a statement of remeasurement gains and losses as the Corporation is not exposed to remeasurement gains and losses.

Financial Assets

Financial assets are assets that could be used to discharge existing liabilities or finance future operations and are not for consumption in the normal course of operations.

Notes to the Financial Statements

Canadian Energy Centre Ltd.
For the period October 9, 2019 to March 31, 2020

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (Cont'd)

(b) Basis of Financial Reporting (Cont'd)

Financial assets are the Corporation's financial claims on external entities and individuals at the period end.

Cash and cash equivalents
Cash comprises of cash on hand and demand deposits. Cash equivalents are short-term, highly liquid, investments that are readily convertible to known amounts of cash and that are subject to an insignificant risk of change in value. Cash equivalents are held for the purpose of meeting short-term commitments rather than for investment purposes.

Accounts receivable
Accounts receivable are recognized at the lower of cost or net recoverable value. A valuation allowance is recognized when recovery is uncertain.

Liabilities

Liabilities are present obligations of the Corporation to external entities and individuals arising from past transactions or events occurring before the period end, the settlement of which is expected to result in the future sacrifice of economic benefits. They are recognized when there is an appropriate basis of measurement and management can reasonably estimate the amounts.

Non-Financial Assets

Non-financial assets are acquired, constructed, or developed assets that do not normally provide resources to discharge existing liabilities, but instead:

(a) are normally employed to deliver the Corporation services,
(b) may be consumed in the normal course of operations; and
(c) are not for sale in the normal course of operations

Non-financial assets are limited to prepaid expenses.

Notes to the Financial Statements

Canadian Energy Centre Ltd.
For the period October 9, 2019 to March 31, 2020

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (Cont'd)

(b) Basis of Financial Reporting (Cont'd)

Tangible Capital Assets
Tangible capital assets are recognized at cost less accumulated amortization, which includes amounts that are directly related to the acquisition, design, construction, development, improvement or betterment of the assets. Cost includes overhead directly attributable to construction and development, as well as interest costs that are directly attributable to the acquisition or construction of the asset. The cost, less residual value, of the tangible capital assets, excluding land, is amortized on a straight-line basis over their estimated useful lives.

The capitalization threshold for all capital assets is $2,000. The Corporation, however, does not have any capital assets. Therefore, there is no tangible capital assets reported in the financial statements.

Prepaid expenses
Prepaid expenses are recognized at cost and amortized based on the terms of the agreement.

Measurement Uncertainty

The World Health Organization declared on March 11, 2020 the outbreak of a strain of the novel coronavirus ("COVID-19") as a pandemic which has resulted in a series of public health and emergency measures that have been put in place to combat the spread of the virus and provide financial assistance, as necessary. The duration and impact of COVID-19 are unknown at this time and it is not possible to reliably estimate the effect these developments will have on the Corporation's financial statements.

Note 3 FUTURE ACCOUNTING CHANGES

The Public Sector Accounting Board has approved the following accounting standards:

- **PS 3280 Asset Retirement Obligations (effective April 1, 2021)**
  Effective April 1, 2021, this standard provides guidance on how to account for and report liabilities for retirement of tangible capital assets.

- **PS 3400 Revenue (effective April 1, 2022)**
  This standard provides guidance on how to account for and report on revenue, and specifically, it addresses revenue arising from exchange transactions and unilateral transactions.

Notes to the Financial Statements

Canadian Energy Centre Ltd.
For the period October 9, 2019 to March 31, 2020

Note 3 FUTURE ACCOUNTING CHANGES (Cont'd)

Management is currently assessing the impact of these standards on the financial statements.

Note 4 APPROVED BUDGET

A budgeted surplus of $117,375 was approved by the Board.

The budget reported in the Statement of Operations reflects the original Corporation surplus and additional reclassifications required for more consistent presentation with current period results.

	March 2020
REVENUE	
Grants	$ 5,000,000
TOTAL REVENUE	**5,000,000**
EXPENSES	
Payroll and benefits	799,345
Sub-contractors	3,882,583
Office infrastructure	86,238
Office supplies	500
Communications and outreach	4,958
Marketing and branding	96,000
Other general and administrative	13,000
TOTAL EXPENSES	**4,882,625**
OPERATING SURPLUS	**$ 117,375**

Notes to the Financial Statements

Canadian Energy Centre Ltd.
For the period October 9, 2019 to March 31, 2020

Note 5 CASH AND CASH EQUIVALENTS

Cash and cash equivalents consist of:

	2020
Cash on deposit	$ 2,707,258
	$ 2,707,258

Note 6 ACCOUNTS RECEIVABLE

Accounts receivable are unsecured and non-interest bearing.

	2020
Accounts Receivable:	
Due from the Government of Alberta	$ 1,000,000
GST Receivable	68,576
Balance at end of period	**$ 1,068,576**

Note 7 FINANCIAL RISK MANAGEMENT

The Corporation is exposed to some financial risks. These financial risks include credit risk and liquidity risk.

(a) Credit Risk

Credit risk relates to the possibility that a loss may occur from the failure of another party to perform according to the terms of a contract. Credit risk on accounts receivable is considered low as significant amounts owing are due from a related party.

As at March 31, 2020, the balance of accounts receivable does not contain amounts that were uncollectible.

(b) Liquidity Risk

Liquidity risk is the risk that the Corporation will encounter difficulty in meeting obligations associated with its financial liabilities. Liquidity requirements of the Corporation are met through adequate grants from the Ministry. The Corporation manages liquidity risks by its budget processes and

Notes to the Financial Statements

Canadian Energy Centre Ltd.
For the period October 9, 2019 to March 31, 2020

Note 7 FINANCIAL RISK MANAGEMENT (Cont'd)

regularly monitoring cash flows to ensure the necessary funds are on hand to fulfill upcoming obligations, including operating expenses.

Note 8 ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

		2020
Accounts Payable	$	512,754
Accrued Accounts Payable		168,053
ATB Alberta Rewards Business Card		10,263
Accrued Salaries and Wages		53,719
Vacation Payable		26,803
Balance at end of period	**$**	**771,592**

Note 9 ACCUMULATED SURPLUS

Accumulated surplus is comprised of the following:

		2020
Surplus:		
Current period operating surplus	$	3,028,927
		3,028,927
Share capital:		
1 Common Share (Note 10)		6,800
		6,800
Balance at end of period	**$**	**3,035,727**

Note 10 SHARE CAPITAL

Share capital is comprised of the following:

		2020
Issued:		
1 Common Share	$	6,800
Balance at end of period	**$**	**6,800**

Notes to the Financial Statements

Canadian Energy Centre Ltd.
For the period October 9, 2019 to March 31, 2020

Note 11 CONTINGENT LIABILITIES

As at March 31, 2020, the Corporation was not named as defendant in any specific legal actions.

Note 12 CONTRACTUAL OBLIGATIONS

Contractual obligations are obligations of the Corporation to others that will become liabilities in the future when the terms of those contracts or agreements are met.

	2020
Obligations Under Contracts:	
Service Contracts	$ 260,304
Balance at end of period	**$ 260,304**

Estimated payment requirements for each of the next eight months are as follows:

	Indigenous Service	**Communications/Marketing Service**	**Total**
April 30, 2020	$ 7,500	$ 28,788	$ 36,288
May 31, 2020	7,500	28,788	36,288
June 30, 2020	7,500	28,788	36,288
July 31, 2020	7,500	28,788	36,288
August 31, 2020		28,788	28,788
September 30, 2020		28,788	28,788
October 31, 2020		28,788	28,788
November 30, 2020		28,788	28,788
	$ 30,000	$ 230,304	$ 260,304

Note 13 APPROVAL OF FINANCIAL STATEMENTS

The Board approved the financial statements of the Corporation.

Schedule 1 - Expenses - Detailed by Object

Canadian Energy Centre Ltd.
For the period October 9, 2019 to March 31, 2020

	2020	
	Budget	**Actual**
Salaries and Benefits	$ 799,345	$ 495,849
Sub-Contracting and Consulting	3,887,542	1,340,853
Advertising, Promotion and Branding	96,000	78,919
Office infrastructure	86,238	30,498
Office, General and Administrative Expenses	13,500	24,954
Total Expenses	**$ 4,882,625**	**$ 1,971,073**

Schedule 2 - Salary and Benefits Disclosure

Canadian Energy Centre Ltd.
For the period October 9, 2019 to March 31, 2020

	2020		
	Base Salary (1)	**Other Cash Benefits (2)**	**Total**
Chief Executive Officer (CEO) (3)	$ 90,980	$ 24,824	$ 115,804
Executive Director (4)	56,736	14,465	71,201
Executive Director (5)	31,020	7,445	38,465
Total Expenses	**$ 178,736**	**$ 46,734**	**$ 225,470**

The Chair and Members of the Board of Directors receive no remuneration for participation on the Board.

(1) Base salary includes regular salary.

(2) Other cash benefits include compensation in lieu of pension and health benefits. No bonuses were paid during the period.

(3) CEO was hired on October 9, 2019 with an annual base salary of $194,252 and additional 14% and 10% of the annual base salary in lieu of pension and health benefits respectively.

(4) Executive Director was hired on December 1, 2019 with an annual base salary of $171,600 and additional 14% and 10% of the annual base salary in lieu of pension and health benefits respectively.

(5) Executive Director was hired on January 27, 2020 with an annual base salary of $171,600 and additional 14% and 10% of the annual base salary in lieu of pension and health benefits respectively.

Schedule 3 - Related Party Transactions

Canadian Energy Centre Ltd.
For the period October 9, 2019 to March 31, 2020

Related parties are those entities consolidated or accounted for on the modified equity basis in the Government of Alberta's Consolidated Financial Statements. Related parties also include key management personnel and close family members of those individuals in the Corporation.

The Corporation had the following transactions with related parties reported in the Statements of Operations and the Statements of Financial Position at the amount of consideration agreed upon between the related parties:

		2020
Revenues		
Grants from Department of Energy	$	5,000,000
		5,000,000
Expenses		
Rent - Department of Energy		30,498
		30,498
Receivable from the Department of Energy		1,000,000
Common Shares - Department of Energy		6,800
Payable to the Department of Energy	$	25,222

Other Financial Information

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Lapse/Encumbrance. 240

Lapse/Encumbrance

The following has been prepared pursuant to Section 24(4) of the Financial Administration Act.

Department of Energy

For the year ended March 31, 2020

(in thousands)

	Voted Estimate [1]	Adjusted Voted Estimate	Voted Actuals [2]	Unexpended (Over Expended)
EXPENSE VOTE BY PROGRAM				
Ministry Support Services				
1.1 Minister's Office	$ 1,070	$ 1,070	$ 940	$ 130
1.2 Associate Minister's Office	572	572	311	261
1.3 Deputy Minister's Office	667	667	606	61
1.4 Associate Deputy Minister's Office	552	552	468	84
1.5 Corporate Services	4,082	4,082	3,360	722
	6,943	6,943	5,685	1,258
Resource Development and Management				
2.1 Energy Operations	21,792	21,792	19,161	2,631
2.2 Energy Policy	43,666	43,666	36,804	6,862
2.3 Industry Advocacy	30,000	30,000	9,273	20,727
	95,458	95,458	65,238	30,220
Cost of Selling Oil				
3 Cost of Selling Oil	83,000	83,000	83,627	(627)
	83,000	83,000	83,627	(627)
Climate Change				
4.2 Regulated Rate Option Price Ceiling	67,200	67,200	52,392	14,808
4.3 Renewable Electricity Program	8,400	8,400	9,094	(694)
	75,600	75,600	61,486	14,114
Market Access				
5.1 Crude by Rail	1,500,000	1,500,000	866,098	633,902
	1,500,000	1,500,000	866,098	633,902
Total	$ 1,761,001	$ 1,761,001	$ 1,082,134	$ 678,867
Lapse/(Encumbrance)				$ 678,867
CAPITAL INVESTMENT VOTE BY PROGRAM				
Ministry Support Services	$ 874	$ 874	$ 32	$ 842
	$ 874	$ 874	$ 32	$ 842
Lapse/(Encumbrance)				$ 842
FINANCIAL TRANSACTIONS VOTE BY PROGRAM				
Resource Development and Management	$ 1,929	$ 1,929	$ 1,779	$ 150
Climate Change	96,970	96,970	96,970	-
	$ 98,899	$ 98,899	$ 98,749	$ 150
Lapse/(Encumbrance)				$ 150

(1) As per “Expense Vote by Program” ,“Capital Investment Vote by Program” and “Financial Transaction Vote by Program” page 85 of the 2019-20 Government Estimates.

(2) Actuals exclude non-voted amounts such as statutory programs, amortization and valuation adjustments.

Annual Report Extracts and Other Statutory Reports

Statutory Report: Public Interest Disclosure Act

Section 32 of the *Public Interest Disclosure (Whistleblower Protection) Act* reads:

32(1) Every chief officer must prepare a report annually on all disclosures that have been made to the designated officer of the department, public entity or office of the Legislature for which the chief officer is responsible.

(2) The report under subsection (1) must include the following information:

(a) the number of disclosures received by the designated officer, the number of disclosures acted on and the number of disclosures not acted on by the designated officer;

(b) the number of investigations commenced by the designated officer as a result of disclosures;

(c) in the case of an investigation that results in a finding of wrongdoing, a description of the wrongdoing and any recommendations made or corrective measures taken in relation to the wrongdoing or the reasons why no corrective measure was taken.

(3) The report under subsection (1) must be included in the annual report of the department, public entity or office of the Legislature if the annual report is made publicly available.

There were no disclosures of wrongdoing filed for the Department of Energy between April 1, 2019 and March 31, 2020.