

Energy

Annual Report **2018–2019**

Note to Readers:

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

Energy

Communications

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Acronyms and Notations

AER	Alberta Energy Regulator
AESO	Alberta Electric System Operator
AMI	Alberta Mineral Information
APMC	Alberta Petroleum Marketing Commission
ARP	Alberta Natural Gas Reference Price
AUC	Alberta Utilities Commission
bbl	Barrel
bbl/d	Barrels per day
CARS2	Corporate Accounting and Reporting System
Cdn\$	Canadian Dollar
Cf	Cubic foot
ECCC	Environment and Climate Change Canada
EFT	Electronic Funds Transfer
EORP	Enhanced Oil Recovery Program
ER&T	Emerging Resources and Technologies Initiative
ETS	Electronic Transfer System
GJ	Gigajoule
ha	Hectare
IDA	Integrated decision approach
IEEP	Incremental Ethane Extraction Program
IMAGIS	Integrated Management Alberta Government Information System
IRMS	Integrated Resource Management System
ISO	Independent System Operator
LAMAS	Land Automated Mineral Agreement System
LNG	Liquefied Natural Gas
MIM	Metallic and Industrial Minerals
MINRS	Metallic and Industrial Minerals Royalty Revenues
MRIS	Mineral Revenues Information System
MW	Megawatt
NEB	National Energy Board
NGAP	Natural Gas Advisory Panel
NGTL	TC Energy Corporation's NOVA Gas Transmission Ltd.
NWRP	North West Redwater Partnership
OASIS	Oil Sands Administrative and Strategic Information System
OPEC	Organization of the Petroleum Exporting Countries
OWA	Orphan Well Association
PDP	Petrochemicals Diversification Program
PFIP	Petrochemical Feedstocks Infrastructure Program
PPA	Power Purchase Agreement
PUP	Partial Upgrading Program
RAM	Royalty and Marketing System
RECSI	Regional Electricity Cooperation and Strategic Infrastructure Initiative
REP	Renewable Electricity Program
RFEOI	Request for Expressions of Interest
RRO	Regulated Rate Option
SCO	Synthetic Crude Oil
Tcf	Trillion cubic feet
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 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 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 Department of Energy, the Alberta Energy Regulator, the Alberta Utilities Commission, the Alberta Petroleum Marketing Commission, the Post-closure Stewardship Fund, and the Balancing Pool.**
- **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.**

In December 2018, government announced changes to the 2018-19 ministry annual reports. Ministry and department audited financial statements previously included in the annual report of the Ministry of Energy have been replaced with the financial information of the ministry on pages 71-175.

Key information previously contained in the annual reports of each of the 21 ministries is now included in the audited consolidated financial statements of the province.

Message from the Minister



As a life-long Albertan, I am deeply honored to have the privilege to serve as the Minister of Energy. Alberta is once again open for business and our government is dedicated to building upon the province's track record of being a place where entrepreneurs thrive, particularly in the energy sector.

It should be noted that information contained in the 2018-2019 Energy Annual Report reflects decisions made prior to the new government's swearing in on April 30, 2019.

We should be proud of our energy sector. Alberta has the third-largest reserves of recoverable oil in the world and the fourth-largest reserves of natural gas. Yet, in recent years, prices have dropped, growth has stalled and we have witnessed a capital flight from Alberta, costing us—and the country—billions in revenue. Even worse, much needed pipeline projects like Northern Gateway and Energy East were cancelled and abandoned.

But there is good news. The energy industry in Alberta can again be one of the most attractive investment destinations in North America. We're doing this through a multi-faceted approach.

First, we are fighting for pipelines. This includes the Trans Mountain Expansion Pipeline project, Keystone XL and Enbridge's Line 3. We will work with stakeholders, including First Nations coalitions, to get shovels in the ground. The Canadian Taxpayers Federation estimates that the federal government has already lost \$12 billion because of a lack of pipeline capacity. We intend to change that. We will also continuously fight the federal government when it comes to unfair legislation, as we have seen with Bill C-69 and Bill C-48.

Second, we are restoring investor confidence by making sure Alberta is the best place to do business. Our government is working to cut red tape and reduce unnecessary and redundant regulations that have been hindering business growth. We are using an outcome-based approach to ensure regulatory processes are necessary, effective, efficient and proportional to the results they are trying to achieve.

Next, we will build upon our reputation as a world leader in responsible energy production. Alberta has some of the world's highest environmental, human rights and labour standards when it comes to energy development. We need to do a better job telling the world about these achievements—and a better job at uncovering foreign-funded misinformation campaigns working to sabotage our industry. To that end, our government will be creating an elite team to dispel myths and lies about the energy industry and tell Alberta's story.

We are also standing up for Alberta's natural gas industry. There will be a growing global demand for natural gas in the coming decades, and our government will work with regulators and industry to streamline project approvals and get full value for this important resource. We will work to ensure we have the infrastructure we need to ship Alberta's natural gas to international markets.

Finally, we are focused on ensuring Albertans have a stable and reliable electricity system. Our electricity grid is the foundation of our lives, and we need to ensure all Albertans can count on a stable, dependable system whether at home or at work. Our plan ensures Alberta has a market-based electricity system that welcomes a diversity of sources while providing affordable electricity to everyone in the province.

Regardless of decisions made in the past, as a new government we look forward to implement our plans to create jobs, stimulate private sector investment and get our energy industry working for Albertans, while maintaining the highest environmental and safety standards. We will continue to stand up for Alberta and protect the value of our energy exports.

Original signed by

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

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 2018*.

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 and the 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

Deputy Minister
Department of Energy

Adrian Begley

Chief Executive Officer
Alberta Petroleum Marketing Commission

Mark Kolesar

Chair
Alberta Utilities Commission

Gordon Lambert

President and Chief Executive Officer
Alberta Energy Regulator

Robert Bhatia

Chair
Balancing Pool

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Results Analysis

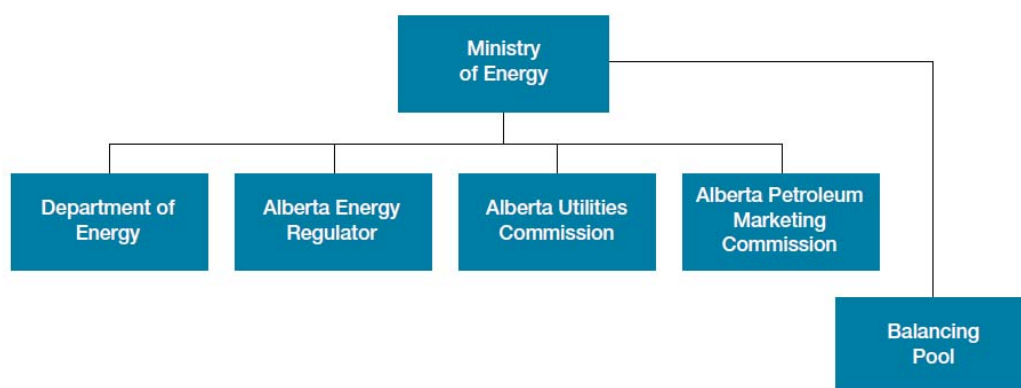
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Ministry Overview

The Ministry of Energy manages Alberta's energy resources to ensure they are developed in responsible ways that benefit and bring value to Albertans. The ministry strives to ensure sustained prosperity in the interests of Albertans through the stewardship of energy and mineral resources. Sustained prosperity includes having 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 Post-closure Stewardship Fund and the Balancing Pool. Each entity plays an important role in overseeing the orderly development of Alberta's energy resources.



The outcomes in Energy's 2018-21 Business Plan are:

- Albertans benefit economically from responsible energy and mineral development and access to global markets.
- Effective stewardship and regulation of Alberta's energy and mineral resources.
- Albertans benefit from a stable, reliable electricity system that protects consumers, attracts investment, and has improved environmental performance.

The shortage of export infrastructure such as pipelines and tidewater ports for access to new markets and consumers has a direct influence on Alberta's oil and gas industry. Without adequate export capacity to move Alberta's products to U.S. refineries and to new global markets, the value that the province can obtain for its oil and gas resources is limited. Without a diversified market base, factors such as future U.S. oil and gas production and the U.S.-Canadian dollar exchange rate can also influence the overall economic benefit derived from resource development in the province. In addition, the oil and gas industry in particular is susceptible to geopolitical uncertainty and commodity price volatility, which has a direct impact on Alberta's industry and in turn, investment and employment, and the overall economy.

The oil and gas industry is at the heart of Alberta's economy. Regulation of energy and mineral development requires a balanced and integrated approach that takes into consideration the range of social, economic and environmental factors which are constantly evolving. Regulatory burden and uncertainty at the federal level can hinder investment in the province's resource industry, and ultimately impact the economic benefits derived from resource development activities.

Department of Energy

- Acts as the steward of Alberta's energy resources on behalf of all Albertans
- Develops policy to guide the management and development of Alberta's non-renewable resources such as conventional and unconventional oil and gas, oil sands, coal, metallic and industrial minerals, and petrochemicals
- Ensures the integration of natural resource 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 minerals
- 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
- Administers the carbon capture and storage Post-closure Stewardship Fund
- Leads Alberta's market access efforts with internal, external and international stakeholders

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
- 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 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 commodity prices used in royalty calculations
- 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

Discussion and Analysis of Results

Non-Renewable Resource Revenue

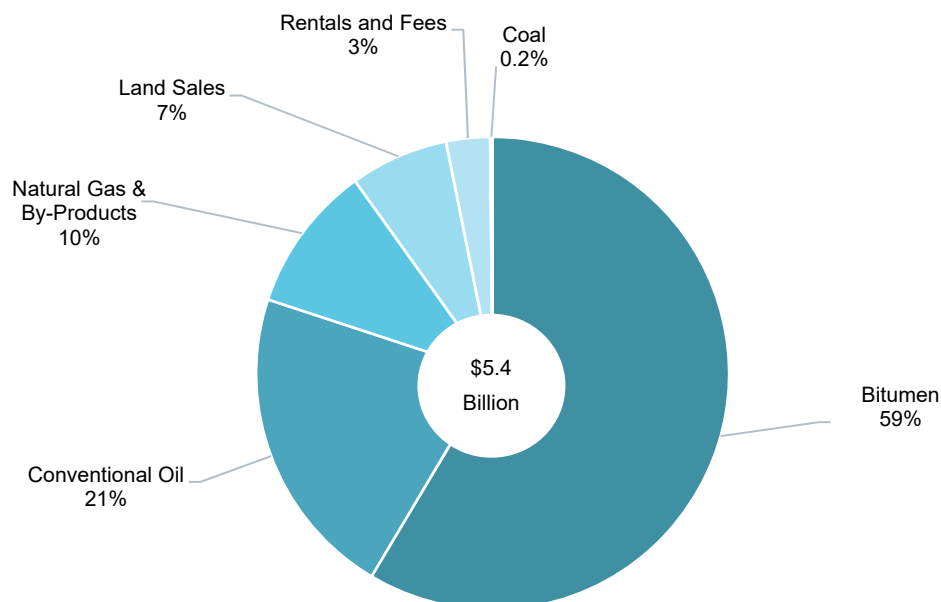
Energy development in Alberta is a key provider of jobs, business opportunities, taxes and royalty revenues that fund important government programs for Albertans. Energy development also drives activity in a number of other industries, including construction and manufacturing, which benefit communities 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. The following table is a comparison of budgeted and actual revenues generated for fiscal year 2018-19. Non-renewable resource revenues totaled \$5.4 billion, \$1.6 billion higher than the budgeted amount of \$3.8 billion.

2018-19 Non-Renewable Resource Revenue



Source: Government of Alberta

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

Non-Renewable Resource Revenue Forecasting

The Government of Alberta is responsible for forecasting non-renewable resource revenues.

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 uses 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 the futures market 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

Commodity Prices	2018-19 Budget	2018-19 Actual
WTI (US\$/bbl)	59.00	62.73
Exchange rate	0.80	0.76
Light-heavy differential (US\$/bbl)	22.35	23.31
WCS (US\$/bbl)	36.65	39.46
Alberta natural gas reference price (Cdn\$/GJ)	2.00	1.34

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

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.

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.

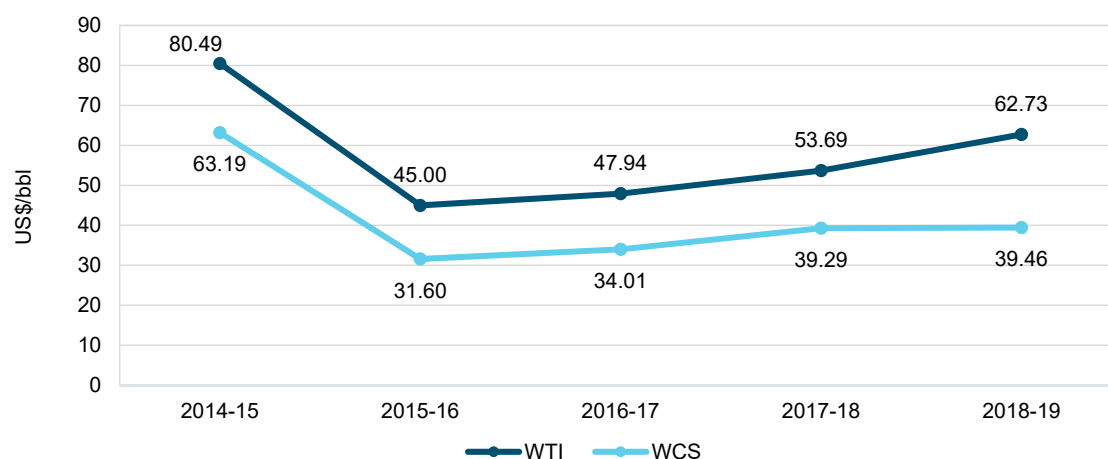
West Texas Intermediate (WTI) is the North American price benchmark for light sweet oil. Western Canadian Select (WCS) is a North American price benchmark for heavy crude oil, commonly used to price Canadian heavy oil.

The WTI price averaged almost US\$93 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 per barrel in June 2014 to around US\$30

per barrel in February 2016. The decline in WTI price was due to a combination of factors, from global supply growth exceeding demand growth, with supply boosted by significant increases, including increases 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 several non-OPEC producers continued to limit production after agreeing 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.

Budget 2018 was based on an estimate of US\$59.00 per barrel price for WTI crude oil and an exchange rate of 80 cents U.S. to the Canadian dollar in 2018-19. The actual WTI price averaged US\$62.73 per barrel in 2018-19. WTI prices continued to trend upward in the 2018-19 fiscal year until October 2018 as global crude supply significantly exceeded demand, leading to an increase in global crude inventory. OPEC and non-OPEC production cut agreement was extended again in December 2018 until June 2019. This agreement, together with U.S. sanctions on Venezuela, supported crude prices in early 2019 with WTI posting monthly increases and reaching US\$58.17 per barrel in March 2019, the highest monthly level since October 2018. Most analysts are forecasting that WTI prices will be supported by the OPEC and non-OPEC supply compliance, and U.S. sanctions on Venezuela and Iran, but restrained by expanding U.S. shale production prompted by the higher prices.

Crude Oil Prices

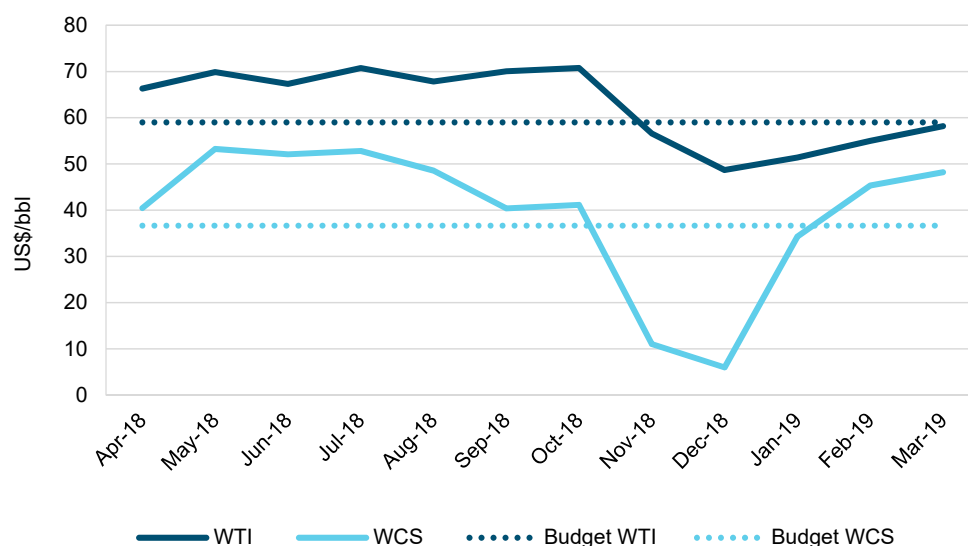


Source: Ministry of Energy

The WCS price was estimated at US\$36.65 per barrel for 2018-19 in Budget 2018. A combination of factors such as persistent global oversupply, continuing build-ups in global inventories, and concerns over demand growth put significant downward pressure on prices; however, once global prices start to recover, WCS generally improves as well. 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 ongoing 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. 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\$39.46 per barrel in 2018-19, slightly higher than budgeted price, mainly due to the Alberta crude oil curtailment initiative and the U.S. sanctions on Venezuela, which contributed to an increase in global and North American heavy oil prices. The actual price exceeded the budgeted price, despite the decline in heavy oil prices that took place towards the end of 2018 due to oil sands production exceeding available pipeline capacity, and delayed response from the crude by rail option. When oil pipelines leaving Canada reach full capacity, Canadian oil prices are discounted to reflect a higher rail transportation cost and receive a larger price discount compared to WTI. This reduces royalty revenues received by Albertans. Nonetheless, as crude oil production from Alberta is exceeding available pipeline capacity, WCS prices are expected to remain low despite a projected increase in global crude oil prices.

2018-19 Crude Oil Prices



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

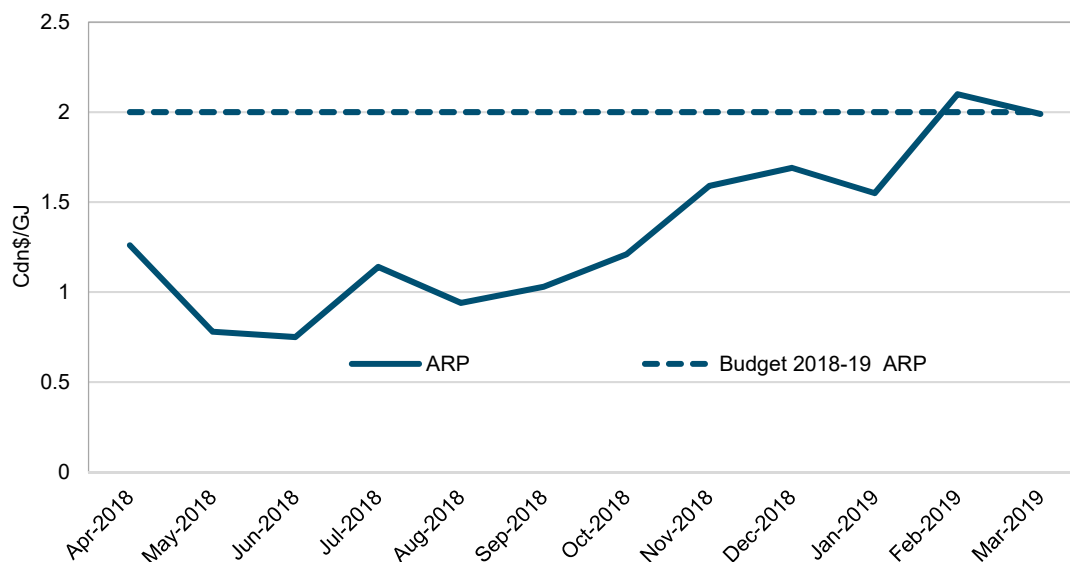
Natural Gas Prices

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 it impacts 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 2018 were based on a gas price forecast of ARP at Cdn\$2.00/gigajoule (GJ). The realized ARP averaged Cdn\$1.34/GJ in fiscal year 2018-19. The actual gas price was below budgeted levels at the end of the fiscal year due to a combination of pipeline maintenance issues, regional surplus from limited outlets to supply, continued U.S. natural gas production growth, robust Canadian production and TC Energy Corporation's restriction protocol during maintenance periods on its pipeline systems in Western Canada.

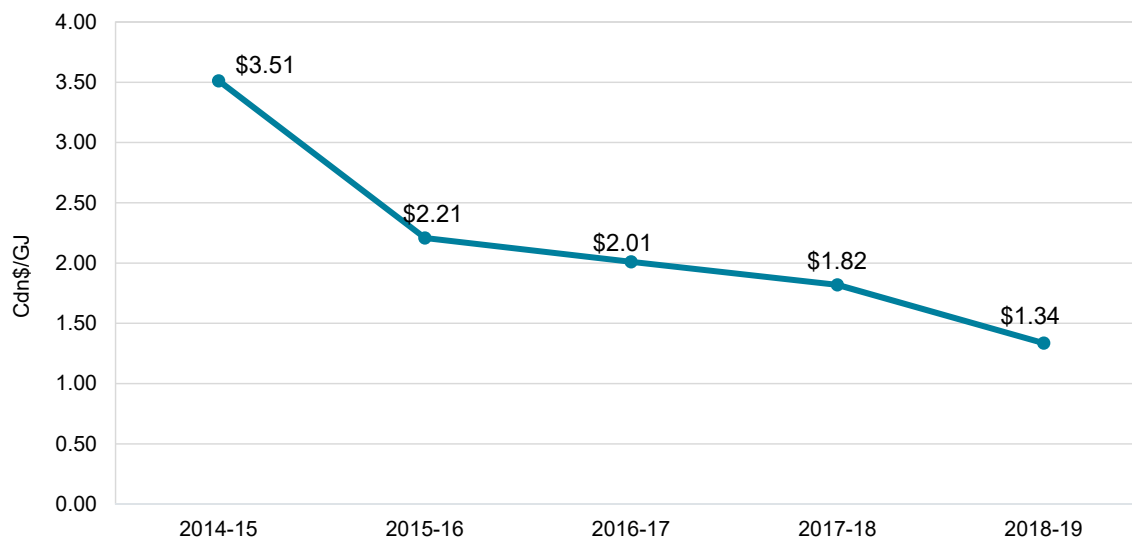
2018-19 Alberta Gas Reference Price



Source: Government of Alberta

Despite other North American benchmark natural gas prices having remained relatively flat year-over-year throughout 2018, AECO prices were particularly weak and volatile due to robust U.S. and Canadian production, as well as infrastructure issues combined with restriction protocol during maintenance periods on TC Energy Corporation's Nova Gas Transmission Ltd (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 Prices



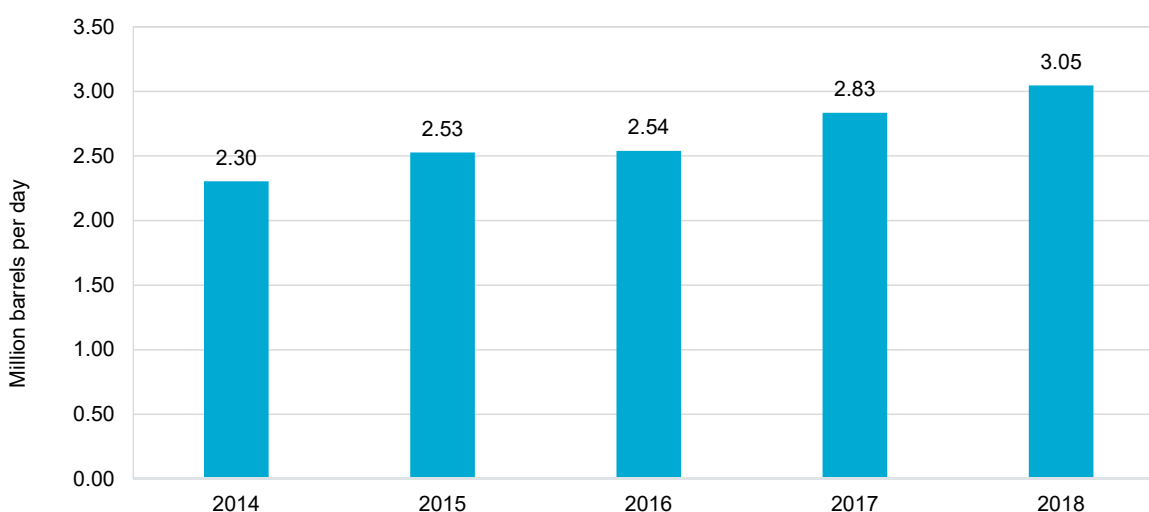
Source: Government of Alberta

Production

Crude Bitumen Production

Crude bitumen production increased by about 7.5 per cent from 2.83 million barrels per day in 2017 to 3.05 million barrels per day in 2018, and therefore continued a rising trend that has been underway since 2008. This was the first time that the annual crude bitumen production in Alberta exceeded three million barrels per day. Total crude bitumen production is comprised of mined production and in-situ production. During 2018, mined production increased by about 15.4 per cent to 1.47 million barrels per day, mainly due to an increase in production from Suncor Energy's Fort Hills mine, Imperial Oil's Kearl mine, and Canadian Natural Resources Limited's Horizon and Athabasca Oil Sands Project mines. In addition, a number of in-situ projects continued to ramp up production in 2018, leading to an overall in-situ production increase of about one per cent to 1.57 million barrels per day. The share of crude bitumen production as a percentage of global consumption also increased in 2018, to 3.1 per cent from 2.9 per cent in 2017.

Alberta Crude Bitumen Production



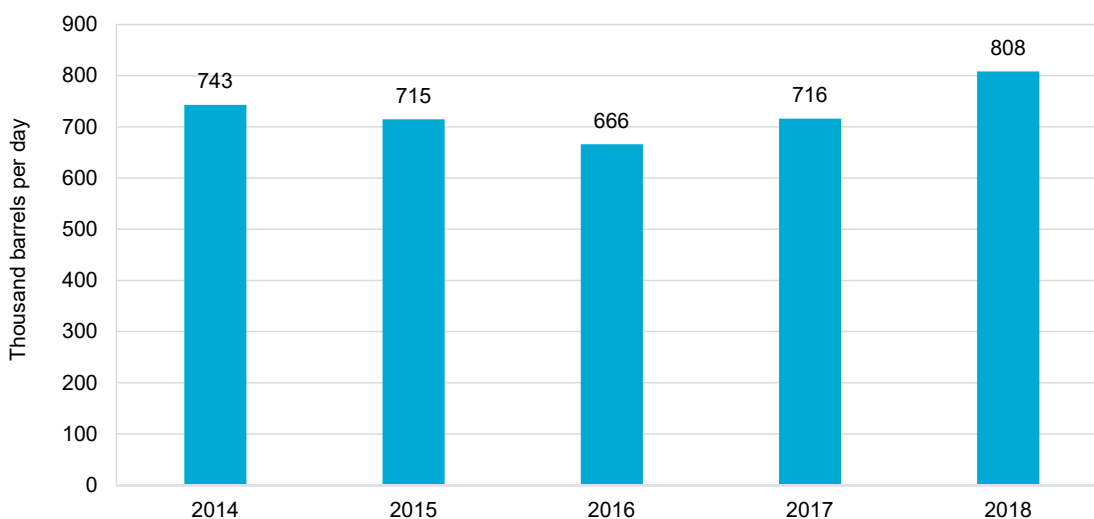
Source: Alberta Energy Regulator

Conventional Crude Oil and Equivalent Production

Production of crude oil and equivalent (condensate and pentanes plus) increased by about 13 per cent, from about 715,800 barrels per day in 2017 to about 808,300 barrels per day in 2018.

Conventional production increased by almost 10 per cent from 2017 to 2018, from about 446,100 barrels per day to about 489,600 barrels per day. According to the Alberta Energy Regulator, higher crude oil prices in 2018 combined with both an increase in initial well productivity and slower decline rates led to increased production for the second straight year. Producers are increasingly commercializing low permeability areas with large volumes of light crude oil, such as the Montney and Duvernay Formations because of the price premium on light oil. The increase in condensate and pentanes plus production continued in 2018; the production went up by about 18 per cent from 269,700 barrels per day in 2017 to 318,800 barrels per day in 2018.

Alberta Conventional Crude and Equivalent Production

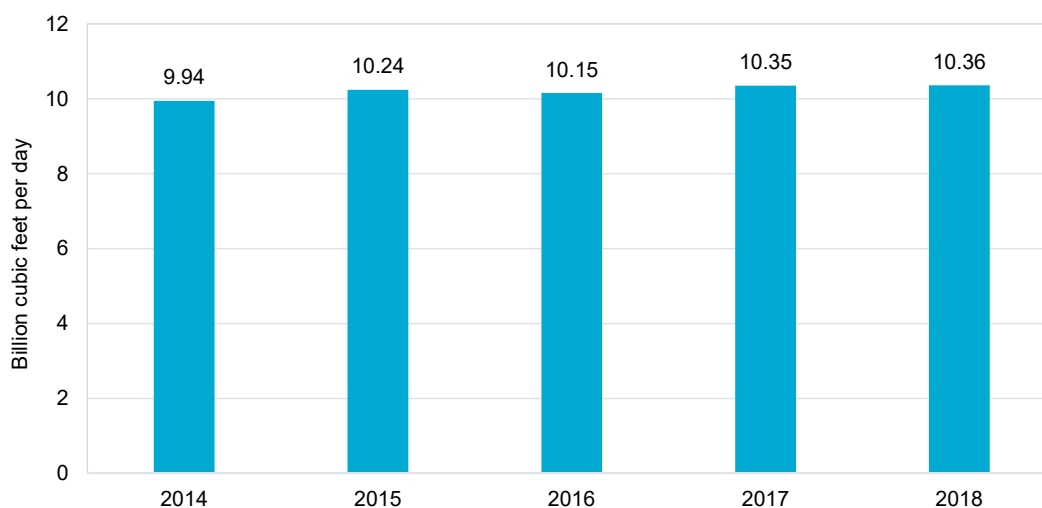


Source: Alberta Energy Regulator

Natural Gas Production

From 2017 to 2018, marketable natural gas production remained almost unchanged, with a 0.01 billion cubic feet per day increase from 10.35 billion cubic feet per day in 2017 to 10.36 billion cubic feet per day in 2018. Production levels observed in 2018 were consistent with the trend over the past few years. Natural gas production has been resilient due to increased drilling for liquids due to solid demand for condensate. Natural gas production from liquids-rich formations is forecast to continue to account for more than half of the natural gas production in the province.

Alberta Marketable Gas Production



Source: Alberta Energy Regulator

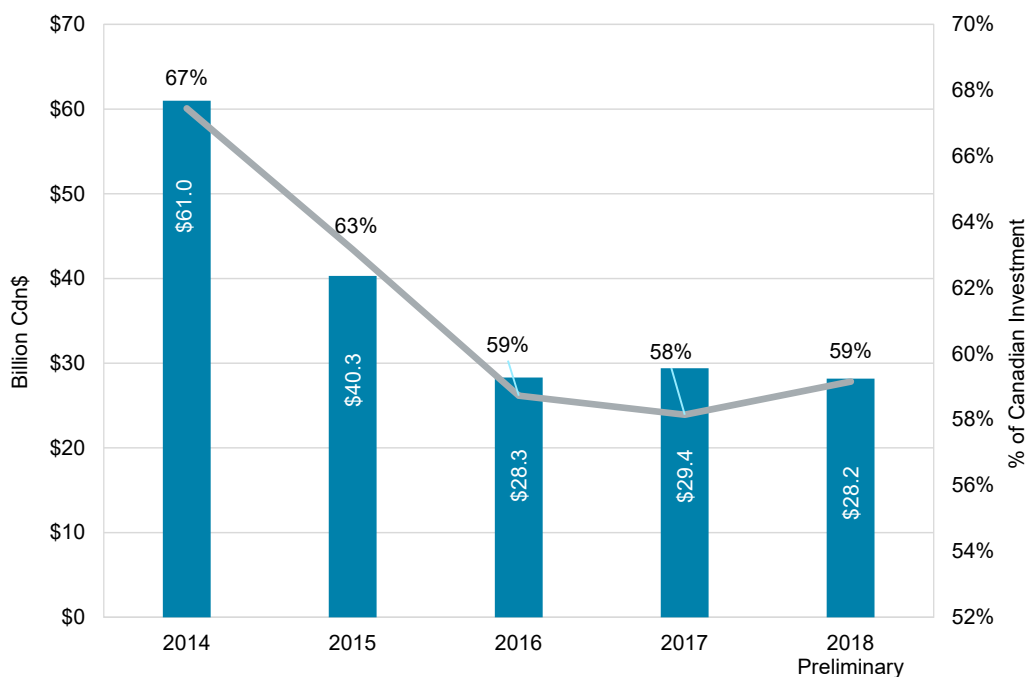
Investment

Industry investment has been vital to the economic performance of the province. 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 has not prevented 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 then. In 2015, Alberta experienced a significant decline in investment in this sector, down to \$40.3 billion, or a 34 per cent year-over-year decline. Investment in the sector has remained below 2014 levels in the years since.

If the 2018 preliminary actual result of \$28.2 billion materializes, investment in Alberta's mining, quarrying, and oil and gas extraction sector would be the lowest since 2009, when investment in the sector was \$21.9 billion. However, 2018 preliminary actuals from Statistics Canada may be revised, since industry activity in the province actually increased in 2018 as oil prices increased from the prior year. The actual results for 2018 is expected to be released in 2020.

The chart below, with the data for the 2014 to 2018 period, demonstrates the importance of Alberta's energy industry investment within the Canadian context.

Capital Investment in Alberta Mining, Quarrying and Oil & Gas Extraction Sector



Source: Statistics Canada

Although the investment in the mining, quarrying, and oil and gas extraction industry in Alberta was down substantially from the 2014 level, Alberta still attracted more investment in this industry than all of the rest of Canada combined. In 2018, Alberta's investment in the upstream energy industry is estimated to have accounted for 59 per cent of the Canadian investment in this industry.

The 2017 results that are reported in the present Annual Report have been revised from the preliminary actuals for 2017 reported in the 2017-18 Annual Report to reflect actual results released by Statistics Canada. The upstream energy industry investment in Alberta for 2017 was \$29.4 billion, accounting for 58 per cent of Canadian production; these results supersede the preliminary actual results that were reported in the 2017-18 Annual Report.

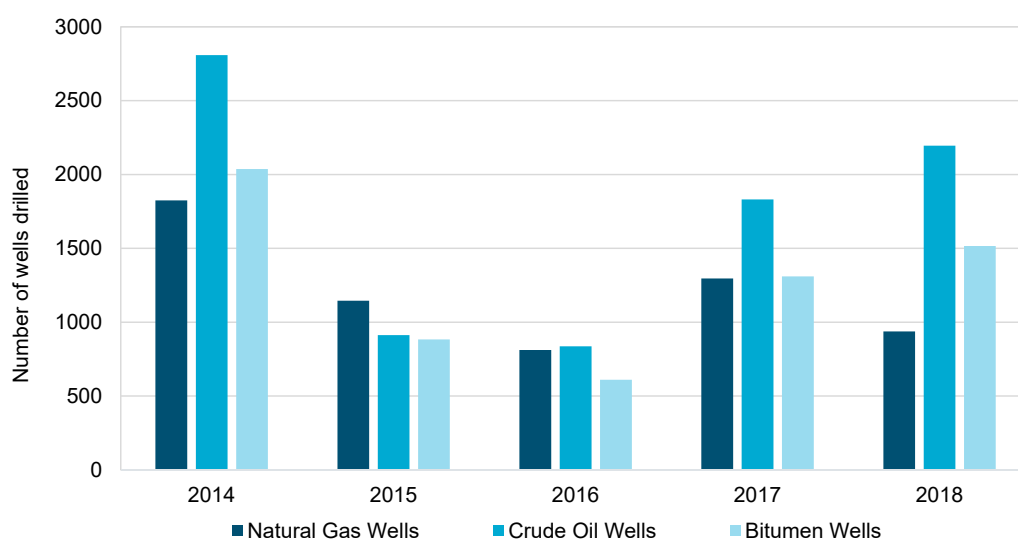
Drilling

The chart below presents drilling activity in Alberta over the 2014 to 2018 period. Wells drilled include both development and exploratory wells. As seen in the chart, after the significant decline in the total number of wells drilled in Alberta that occurred 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.

The total successful natural gas wells drilled decreased by 28 per cent, from 1,295 in 2017 to 937 in 2018. Although the low gas price environment created challenges for the natural gas sector in 2018, newer and higher productivity wells in the Foothills Front Region sustained raw gas production.

Conversely, the total successful crude oil wells drilled increased by 20 per cent, from 1,831 in 2017 to 2,194 in 2018. Stronger oil prices encouraged more drilling activity in 2018, especially with light oil and natural gas liquids in the Montney and Duvernay formations. New wells continue to become more efficient in terms of drilling times, costs, and production rates. Many of the advancements in oil drilling can be applied to gas production, including the use of horizontal multistage fracturing and more fracturing stages per leg. Bitumen wells drilled followed a similar trend to crude oils, increasing by 16 per cent from 1,309 in 2017 to 1,515 in 2018.

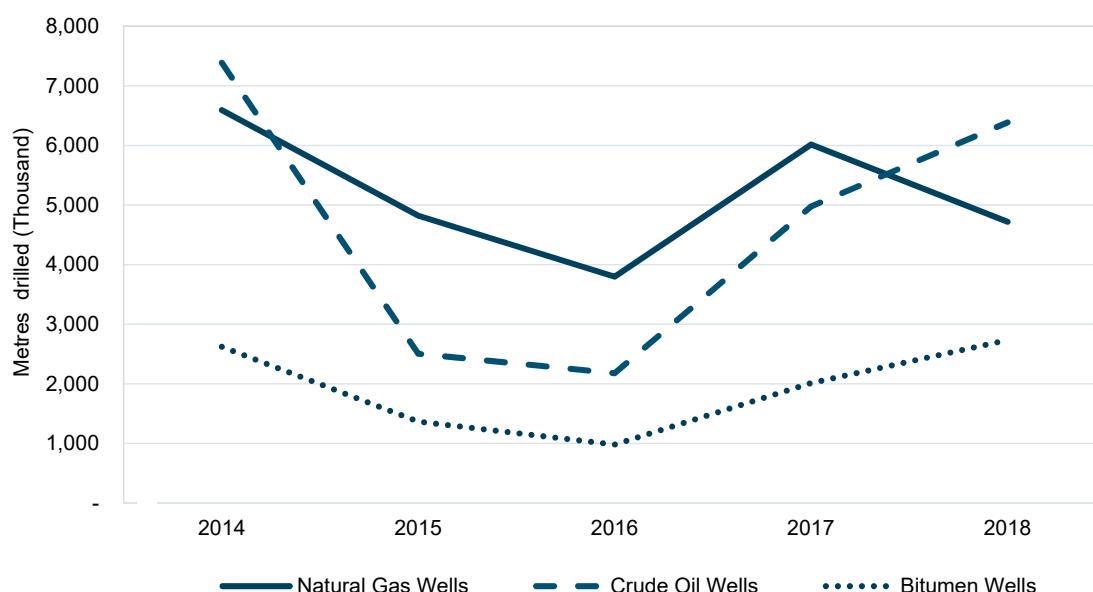
Drilling Activity in Alberta



Source: Alberta Energy Regulator

Over the 2014-2018 period, the number of metres drilled for natural gas, crude oil and bitumen wells reached the lowest level in 2016. Over the 2016-2018 period, the number of metres drilled for crude oil and bitumen wells are demonstrating more horizontal drilling and multistage fractured wells and an increase on drilling activity beyond that shown by just the number of wells.

Wells Metres Drilled



Source: Alberta Energy Regulator

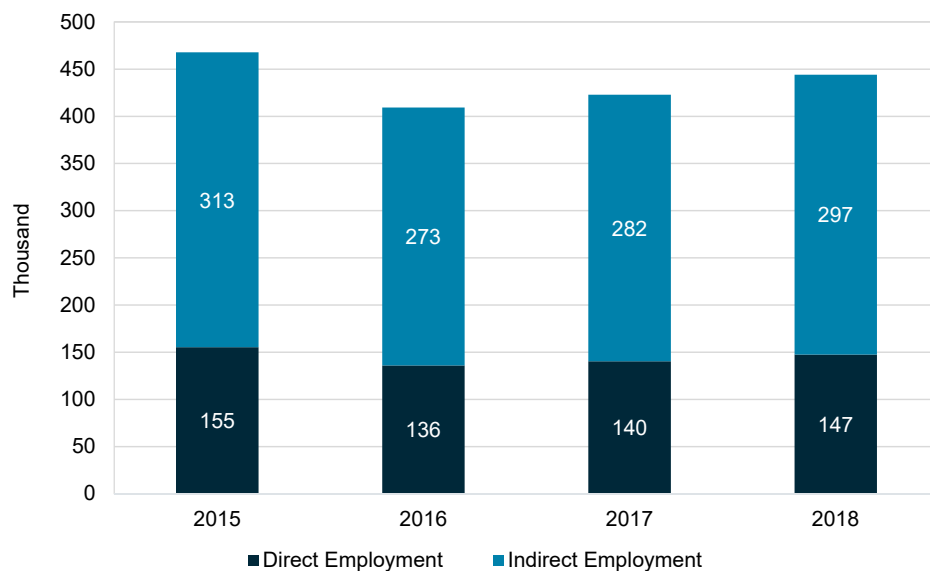
Employment

Upstream energy sector employment has been important to the economic performance of Alberta. The 2014 decline in oil prices had a major impact on employment in Alberta's mining, quarrying, and oil and gas extraction sector. Over the 2014 to 2016 period, direct employment in this sector in Alberta declined by about 23 per cent, from 175,000 to 136,000 people. However, 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.

When indirect employment in the mining, quarrying, and oil and gas extraction is taken into account, Alberta's total employment in the sector increased from about 423,000 people in 2017 to approximately 444,000 people in 2018; total direct and indirect employment in the sector in 2018 corresponded to about 19 per cent of total employment in Alberta in 2018. 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 2015 to 2017 period have been retroactively revised in this annual report from what was reported in the 2017-18 Annual Report to reflect a more current multiplier from Statistics Canada. This revision has resulted in a substantial upward revision of indirect employment results for this period.

Employment in the Mining, Quarrying and Oil & Gas Extraction Sector



Source: Statistics Canada

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 or oil sands 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 2018-21 Business Plan: Albertans benefit from 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.

This section presents program results for the department's royalty programs for the 2017 calendar year, as well as the royalty adjustments for crude oil, natural gas and by-products for the 2018-19 fiscal year. While the program results and royalty adjustments are related, each royalty revenue adjustment needs to be interpreted in its own unique context. These numbers are generated using different data sources and methodologies, and are for different purposes, and, as such, are not directly comparable.

It is important to keep in mind that:

- The actual royalty revenues are revenues the Crown collects on production from all wells in the province and are reported in the financial statements on a fiscal-year basis.
- Royalty adjustment refers to the amount by which royalty was reduced from what would have been assessed under the generic royalty formulas due to a particular royalty program. The royalty adjustments are for wells that qualified under the royalty programs and are reported in the financial statements on a fiscal-year basis.
- The total royalty revenue of each royalty program is sourced from various royalty reporting systems for crude oil, natural gas and oil sands. These systems are reported on a calendar-year basis and reflect the amendments filed by industry each year. Amendments 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.

Most of the royalty programs provide royalty adjustments early in the life cycle of the well or project while revenues from wells participating in the program occur during the entire production life of a well. Therefore, comparing the royalty adjustments against the royalty revenue is only relevant when done over the life of each well or project and should take into account, as far as possible, the value of investments that would not have been made without the program.

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

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 new 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 and replaces the Enhanced Oil Recovery Program that is being phased out.

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.

Alberta is encouraging the use of enhanced recovery methods for petroleum and natural gas through the Enhanced Hydrocarbon Recovery Program. This program aims to conserve the province's resources by targeting different recovery methods that use fluid injection such as hydrocarbons, carbon dioxide, nitrogen or chemicals.

During the 2018 calendar year, the Enhanced Hydrocarbon Recovery Program received 11 applications. In total, 21 applications from 15 companies have been received since the program's inception. Two applications for secondary recovery of oil, which includes enhancing the recovery of oil from an oil pool by water flooding, gas cycling, gas flooding, polymer flooding or similar methods, were approved during the 2018 calendar year.

Benefit schedules were finalized in November, 2018 and applications are being processed in accordance with that schedule. The first year of production under the program occurred in 2018. This production performance will be reported in next year's annual report.

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.

Since the program's inception, a total of 17 applications were received from 11 companies that have shown interest in the program. In 2018, the Emerging Resources Program received five applications that are under review. Four applications that were received in 2017 were approved during the 2018 calendar

year. Final benefit details were finalized in September 2018 and additional applications in review and processing.

Revenue and production data for the four applications approved during the 2018 calendar year will be reported in next year's annual report.

Alberta Royalty Framework's Royalty Programs

The department has a number of royalty programs under the Alberta Royalty Framework that are no longer accepting new entrants as of 2017 and will be phased out once their regulation expires. They will be replaced by the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program, as described above. 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.

In the 2018-19 fiscal year, 11 royalty programs provided more than \$953.4 million in royalty adjustments to oil and gas producers.

Royalty Program	2017-18 Royalty Adjustments (\$ Millions)	2018-19 Royalty Adjustments (\$ Millions)
Natural Gas Deep Drilling Program	\$1,071.6	\$676.8
Shale Gas	\$199.0	\$159.4
Horizontal Oil	\$87.0	\$44.6
Incremental Ethane Extraction Program	\$63.4	\$28.8
Enhanced Oil Recovery Program	\$21.5	\$21.2
Proprietary Waiver	\$2.3	\$15.4
Horizontal Gas	\$10.3	\$6.9
Otherwise Flared Solution Gas	\$0.2	\$0.1
Deep Oil Exploratory Well	\$0.1	\$0.1
Innovative Energy Technologies Program	\$0.1	\$0.0
Coalbed Methane	\$0.0	\$0.0
Total Royalty Adjustments	\$1,455.7	\$953.4

Note: totals may not add up due to rounding.

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 well's 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 12.9 per cent and liquids production has increased by 9.3 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 production is a result of the low gas price and high natural gas liquids prices, which incents liquid rich production and deeper cut natural gas processing. This price environment is the result of high localized demand for pentanes plus, a mix of natural gas liquids used as diluent, mixed with bitumen to reduce viscosity and allow the resulting dilbit blend to be shipped on pipelines.

	Prior Year's Results				Current 2017
	2013	2014	2015	2016	
Total gas production from eligible wells	Residue Gas: 21,922,278	Residue Gas: 28,557,344	Residue Gas: 35,335,955	Residue Gas: 38,752,706	Residue Gas: 33,746,930
	Liquids: 3,987,520	Liquids: 6,503,491	Liquids: 9,182,083	Liquids: 12,138,887	Liquids: 13,274,152
Total Royalty from NGDDP gas wells	\$211 million	\$378 million	\$280 million	\$261 million	\$307 million

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

The total royalty revenue for NGDDP has increased by 17.7 per cent from the 2016 result. In the 2017 calendar year, gas wells in the program contributed about \$307 million in total royalty revenues. Total royalty revenue has increased by over \$46 million from 2016, despite a decrease in gas and an increase in the liquids production from eligible wells over the same period. Higher NGDDP royalty revenue despite decreased gas production is the result of increased liquids production and higher local market prices for liquids, particularly pentane and higher carbon number hydrocarbons, relative to gas. This is mainly due to the high localized demand driven by bitumen producers' need for diluent to ship their product. Additionally, natural gas liquid's reference prices were higher in 2017 than in 2016.

NGDDP no longer accepts new wells into the program as of December 31, 2016 and no new wells were drilled since 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 were accepted into the program after 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 2017, no new wells qualify 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.

Overall production from **horizontal oil and gas** wells decreased in 2017 compared to 2016. Gas production under the horizontal gas new wells decreased to 4.3 billion cubic metres from 7.6 billion cubic metres in 2016. Liquids production also saw a decrease to 2.9 million cubic metres from 3.4 million cubic metres in 2016.

Horizontal oil wells showed decreases of 45.6 per cent and 51.5 per cent in 2017 oil production and solution gas production, respectively from 2016 to 2017. Oil production decreased to 2.4 million cubic metres from 4.5 million cubic metres in 2016. Solution gas production decreased to 0.4 billion cubic metres from 0.9 billion cubic metres in 2017. 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 2017 calendar year, gas production from shale wells decreased to 0.6 billion cubic metres from 0.9 billion cubic metres from 2016 level.

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.

The total royalty revenue for ER&T in 2017 was \$238.9 million compared to the 2016 total royalty revenue of \$125.7 million. This accounts for 14.8 per cent of Alberta's total conventional Crown oil and gas revenues. Total revenue generated by wells in the program has increased by 90.0 per cent compared to 2016, which was an increase of 45.9 per cent from 2015. The significant drop in commodity prices in 2015 and 2016, the expected decline of existing wells, and the reduction in new wells qualifying for the program all reduced the qualifying production from this program. On the other hand, the increase in West Texas Intermediate (WTI) prices in 2017, which influenced both oil and natural gas liquid prices, increased the value from Emerging Resource and Technologies Initiative production, therefore lead to an increase in ER&T royalties.

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 2017-18, 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. In the 2018-19, the department issued approximately \$17.1 million in royalty credits to these projects for 2017 production.

About 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 of Energy 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 (EORP) 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 2017 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 2017 was 0.7 million cubic metres, which is an increase of 12,793 cubic metres from the previous year. The Crown royalty volumes from active EOR schemes totaled 103,927 cubic metres, which translates to about \$37.2 million in total royalty revenue in 2017. The total royalty revenue increased by \$13.6 million in 2017 from the \$23.6 million reported in 2016. This can be attributed to the slightly higher oil prices in 2017, as royalty rates are responsive to both production and commodity price under the Alberta Royalty Framework. Of this total royalty revenue, \$34.6 million was considered incremental royalty to the Crown that otherwise would not have been generated without the program. This is a \$12.9 million increase from the \$21.7 million in incremental royalty revenue reported in 2016.

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.

Outcome One

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

The ministry develops and manages policies and programs related to the province's tenure and royalty system. It accurately calculates and collects revenues from energy and mineral royalties, mineral rights leases, bonuses and rent. The ministry explores ways to encourage value-added processing within the province through the diversification of the energy resources. This includes management of its processing and other agreements respecting bitumen processing at the Sturgeon Refinery through the Alberta Petroleum Marketing Commission (APMC). In addition to diversification efforts, the ministry monitors and takes steps to protect the value of Alberta's resources, including temporary mechanisms in 2019 to bring oil production in better alignment with transport capacity. The Ministry of Energy also represents Alberta in intergovernmental initiatives such as the Canadian Energy Strategy and the Energy and Mines Ministers' table to ensure they reflect Alberta's interests. It continues to advocate for increased pipeline access to global markets and address pipeline constraints to strengthen both provincial and national economies.

Key Strategies

Achieving optimum value for Albertans in the development of energy and mineral resources is significantly affected by appropriate market access and energy related infrastructure. Geopolitical uncertainty and commodity price volatility also continue to impact this risk. Market demand continues to affect this risk and is connected to future United States production capacity and the value of the Canadian dollar. The ministry continued to advocate for increased pipeline access to global markets to ensure Alberta gets more value for its products. The ministry's royalty programs and energy diversification programs also acted to manage this risk by providing incentives for investment.

1.1 Develop policies and initiatives that support the diversification of energy resource value chains and value-added processing in the province.

Energy Diversification Programs

In recent years, Alberta energy producers have faced competition in the U.S. and central Canadian markets. In order to support long-term growth and to optimize value for Albertans as resource owners, the province needs to diversify the markets for its products.

Three programs were introduced to add more value to the products through local processing before they are exported. In 2018-19, the Ministry of Energy completed the application season for the second round of the Petrochemicals Diversification Program (PDP), the Petrochemicals Feedstock Infrastructure Program (PFIP), and collaborated with APMC to implement the Partial Upgrading Program (PUP), which were announced in March 2018. These three programs were created under the *Energy Diversification Act*.

Petrochemicals Diversification Program (PDP)

PDP was originally launched in 2016 to enable construction of new and expanding 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 and fertilizers. Under the program, approved projects are issued royalty credits once the facilities become operational.

When PDP Round One was launched in February 2016, the province committed \$500 million in royalty credits for two projects implementing value-added processing in Alberta. Two companies were approved under the first round to undertake these projects.

PDP Round Two was designed to encourage the construction of new and expanding petrochemical facilities in the province by providing up to \$500 million in royalty credits. In November 2018, the funding for the program was increased to up to \$1.1 billion in royalty credits. The application open season for PDP Round Two closed on October 1, 2018 and to date, two projects were approved to receive royalty credits once they are in operation.

Inter Pipeline expects to make a final investment decision on its \$600 million acrylic acid facility by July 31, 2020 and begin operations by December 31, 2022. Naticol Energy plans to be in a position to sanction the project by December 31, 2019 and have the facility in-service by June 30, 2022.

Partial Upgrading Program (PUP)

PUP was designed to encourage companies to build two to five bitumen upgrading facilities in Alberta over the next eight years. Partial upgrading reduces the thickness of oil sands bitumen so it can flow through pipelines more easily. Upgrading bitumen reduces the amount of diluent that needs to be added to the bitumen in order to transport it by pipeline. This lowers industry costs and allows more of the product to be shipped since there is less diluent in the mix. This can enhance the competitiveness of Alberta's oil sands industry. Partial upgrading would also enable more refineries to process Alberta bitumen which can enhance the competitiveness of Alberta's oil sands sector.

The application open season began on June 11, 2018 and applications were received for PUP until September 4, 2018. Following the evaluation process, APMC entered into a non-binding letter of intent with Value Creations Inc.

Petrochemical Feedstocks Infrastructure Program (PFIP)

PFIP was created to encourage industry to build facilities that supply natural gas liquids feedstock required for petrochemical manufacturing by providing up to \$1 billion in grants and loan guarantees to successful project proposals. This program is intended to encourage midstream projects that support extraction and supply of natural gas components for feedstock. Feedstocks such as ethane, methane, propane and butane are ingredients used in products like electronics, plastics, fabrics and fertilizers. Increasing the province's supply of these raw components supports the expansion of Alberta's petrochemical processing sector, expands the market reach internationally and capitalizes on increased consumer demand for products in Asia.

The Ministry of Energy initiated the program in 2018-19 and received applications until October 1, 2018.

Exploring Future Refineries in Alberta

During 2018-19, the Government of Alberta explored the role of refineries in energy diversification and economic activity in the province.

In response to industry encouragement, the province issued a Request for Expressions of Interest (RFEOI) on December 11, 2018 to determine the business case for investing in a new refinery or related infrastructure in Alberta.

The RFEOI submission period closed on February 8, 2019. A number of Expressions of Interest were received.

Sturgeon Refinery

During 2018-19, the APMC prepared for the start-up of the Sturgeon Refinery. Full commercial operations is currently targeted for the end of 2019 due to delays in switching the refinery feedstock from synthetic crude oil to bitumen.

The APMC's role in the North West Redwater Partnership (NWRP) includes feedstock provider, toll payer, and subordinated debt lender. APMC is responsible for supplying 75 per cent of the refinery bitumen feedstock, retaining 75 per cent of the refined products and paying 75 per cent of the cost of service toll for processing.

The commission has borrowed a total of \$439 million from Treasury Board and Finance to lend to the Sturgeon Refinery. The timelines for the commission repaying the debt to Treasury Board and Finance corresponds to the NWRP repayment of the term loan to the commission.

While loans to NWRP are outstanding, APMC obtains a voting interest (25 per cent) of the NWRP Executive Leadership Committee, which is in proportion with its contribution to equity. This has provided APMC with some involvement in the refinery's business, but does not extend to control over the construction or engineering. In addition, APMC remained fully engaged through participation in the Operations Committee, Operations Executive Leadership Committee, Health, Safety and Environment Committee and the Finance Committee. APMC also participated in regular commercial steering committee meetings to discuss and assess potential feedstock and offtake marketing arrangements. APMC continues to participate in the new steering committee to align financial and operational processes for the application of the cost of service toll outlined in the processing agreements.

The most fundamental risk to APMC relating to the Sturgeon Refinery is that the difference in price between final products (diesel and diluent) and the feedstock (diluted bitumen) will not be enough to cover the cost of upgrading and refining the feedstock due to market conditions. If there is a narrow differential between bitumen and light oil and products, then the refinery contract could result in losses. If there is a wide differential, then it can result in positive cash flow. While this risk cannot be directly managed, part of the value of the arrangement is that it provides hedging on a small part of Alberta's bitumen. If the differences between bitumen and light oil are wide, province-wide royalties will be lower but the refinery contract will be more profitable. If the differences are narrow, the refinery contract will be less profitable but royalties will be higher. This is a recognized cost and benefit of such a physical hedge. The department expects phase 1 of the project to provide positive returns for Albertans. Returns 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.

1.2 Improve market access for Alberta's energy resources and products by emphasizing Alberta's commitment to reducing carbon emissions and fostering and strengthening energy-related relationships nationally and globally.

Strengthening Energy-Related Relationships and Promoting Alberta's Interests

In 2018-19, the province took a number of measures to protect the value of its resources, including efforts to diversify the energy industry, manage production, storage, and export to get the best value for Alberta's oil and continuing to advocate for pipelines. It is recognized that without more pipelines coming online, Alberta will continue to face the challenge of discounted prices. Sustained advocacy efforts in Canada and the U.S. are key to addressing the constraint and getting Alberta's resources to U.S. refineries and new, offshore markets. Throughout 2018-19, the Government of Alberta engaged in a range of activities in Canada and the U.S. to strengthen energy-related relationships.

In June 2018, government attended the Global Petroleum Show in Calgary, Alberta, June 12-14, 2018, and advanced Alberta's energy priorities through several engagements with international stakeholders including Cosmo Oil (Japan), Japan Canada Oil Sands Limited, and the Texas Secretary of State, Rolandos Pablos.

In June 2018, government attended the Energy Council in Regina, Saskatchewan. Government emphasized the importance of energy trade with the U.S. and highlighted the value of Alberta's energy sector as a resilient, secure, and desirable place to do business and maintain climate change commitments. Over 60 U.S. elected officials attended the conference.

In July 2018, government attended the Stampede Investment Forum in Calgary, Alberta. Government advanced relations with American counterparts on U.S. market access through participation in the U.S. Relations Working Group Meeting. In addition, government promoted investment attraction through meetings with the Kuwait Petrochemical Industries Company, the Canada United Emirates Business Council, and Astomos Energy of Japan.

In September 2018, government hosted the China-Alberta Petroleum Centre Annual Board Meeting and events in Edmonton, Alberta. The ministry leveraged this event to highlight investment opportunities in Alberta as well as the skills of Alberta's environmental service companies. In addition, the ministry reinforced Alberta's commitment towards tidewater market access and desire to market Alberta's energy products in Asia.

In September 2018, the ministry, in collaboration with the Ministry of Indigenous Relations, Ministry of Environment and Parks and the Ministry of Economic Development, Trade and Tourism completed a mission to New York City to leverage Climate Week and promote investor confidence. The Government of Alberta delegation held a number of meetings with investment firms and climate change representatives from the Government of Canada as well as the United Nations. The delegation also hosted a dinner reception to highlight Alberta's commitment to responsible energy development.

In March 2019, government completed a mission to Houston, Texas to attend CERAWEEK 2019 and conduct bilateral meetings. The ministry highlighted the value of market access through engaging a number of American pipeline operators to seek opportunities to transport Alberta crude. In addition, the ministry highlighted investment attraction through engaging with a number of liquefied natural gas and electricity generation firms to highlight investment potential in Alberta.

Alberta's support of pipeline infrastructure and market access is crucial to the province's energy industry and overall economy. The Government of Alberta will continue to advocate and work through regulatory processes and legal challenges until additional pipelines come online.

Bill 12: *Preserving Canada's Economic Prosperity Act*

The province's economy experienced growth in 2017 and 2018, and it is important to ensure that this growth continues through getting the best value for the province's resources. In May 2018, Bill 12: *Preserving Canada's Economic Prosperity Act* was passed to ensure that Albertans receive maximum value for the province's natural resources.

This act gives government the authority to require companies to obtain a licence before exporting energy products including natural gas, crude oil, and refined fuels such as gasoline, diesel and jet fuel from Alberta via pipeline, rail or truck. This enables government to ensure that adequate pipeline capacity is available to maximize the return on resources, and better manage supply and storage of resources.

Production Curtailment

During 2018, Alberta production began to exceed local market demand and the capacity of pipelines and available rail ("takeaway capacity") to take oil to other markets.

Two major cross-border pipeline projects – Keystone XL and the Line 3 Replacement Project – continued to be delayed as well as Trans Mountain.

In order to better match anticipated production with capacity, in December 2018, the Government of Alberta put in place a temporary limit on industry-wide oil production that took effect in January 2019.

Production limits began in January 2019, and were set at the following levels:

- 3.56 million barrels per day (bbl/d) for January
- 3.635 million bbl/d for February and March
- 3.66 million bbl/d for April
- 3.685 million bbl/d for May
- Announced 3.71 million bbl/d for June

Trans Mountain Expansion Project

In May 2018, government announced a \$2 billion financial backstop in support of the federal government's purchase of the Trans Mountain Expansion Project. No agreements were concluded by fiscal year end.

In May 2018, the Government of Alberta launched the Keep Canada Working national advertising and advocacy campaign in support of the Trans Mountain Expansion Project. In January 2019, the Government of Alberta participated in opposition to the Stand.earth legal motion that sought to delay the National Energy Board's (NEB) reconsideration of the Trans Mountain Expansion Project. The NEB ultimately ruled against Stand.earth.

Through much of 2018, the Government of Alberta supported the reference case on heavy oil transport. The final submissions by the Attorney General of B.C. and Attorney General of Canada were submitted in February 2019, for the March 2019 hearing.

Keystone XL and Line 3

The Government of Alberta continued to advocate for the development of Keystone XL and Enbridge's Line 3 Replacement Projects that continue to face regulatory and legal challenges in the U.S. The Government of Alberta provided written comments to the U.S. State Department regarding the Draft Environmental Assessment and Draft Supplemental Environmental Impact Statement in support of the Keystone XL Mainline Alternative Route Project, and is preparing to do so for the forthcoming State Department posting of a revised Supplemental Environmental Impact Statement.

In November 2017, the Government of Alberta, through the APMC entered into agreement with TC Energy Corp to commit 50,000 barrels per day on the Keystone XL pipeline to assist TC Energy Corp in achieving its final investment decision. In 2018, the commitment was transferred to another shipper which eliminated the future financial commitment and exposure to differential risk by APMC on that pipeline while resulting in sufficient shipper support for the project to be viable at, ultimately, no cost to government.

Crude by Rail

In February 2019, the Government of Alberta announced a \$3.7 billion program to increase rail capacity to help transport Alberta's oil to markets in the medium-term (three years) until new pipeline capacity is in service. This investment was announced to address pipeline constraints and includes leasing about 4,400 rail cars to move up to 120,000 barrels per day 2020, with the expectation of shipments starting as early as July 2019. The current government is reviewing this commitment in order to properly place the contracts in the hands of the private sector.

Federal Bills C-48 and C-69

Federal bills related to resource development will have significant impacts on Alberta's resource industry. Bill C-48, the proposed oil tanker moratorium off the north coast of B.C., and Bill C-69 which will overhaul how major infrastructure projects such as pipelines, electricity transmission, highways, bridges and ports will be reviewed and assessed by the federal government, are already creating investor uncertainty and affecting the province's competitiveness as a viable place for resource development.

The Government of Alberta continued to advocate for Alberta's interests on federal legislation affecting resource development activities. On June 13, 2018, the Government of Alberta sent a letter to Senator David Tkachuk, chair of the Senate committee studying the bill, in response to Bill C-48. On March 18, 2019, a follow-up letter was sent to Senator Tkachuk, which outlined the Government of Alberta's significant concerns and stated that Alberta believes the bill arbitrary and discriminatory.

Advocacy continued on Bill C-69 as well. On May 31, 2018, the Government of Alberta sent another letter and technical submission about Alberta's significant concerns with Bill C-69 to the federal government. Then, on October 9, 2018, the Government of Alberta sent a letter and technical submission to Prime Minister Trudeau reiterating Alberta's concerns with Bill C-69 and the lack of consultation on the bill by the federal government, and included several proposed amendments. The province will continue to provide input into federal processes to ensure that Alberta's interests are defended against the federal government's efforts to change regulatory processes for resource and infrastructure development.

Natural Gas Advisory Panel (NGAP)

The Natural Gas Advisory Panel (NGAP) was established in May 2018 to provide advice and recommendations on short-, medium-, and long-term actions the Government of Alberta could take to ensure Alberta is receiving maximum value for its natural gas resources from available or potential markets.

The panel provided a report to the minister in October 2018 which outlined recommended actions that government could consider to grow Alberta's natural gas sector. The report outlined 48 technical and specific recommendations to grow the natural gas sector, including ways to improve pipeline capacity, regulatory standards and metrics, timeframes for project approvals, transparency and accountability, and setting a vision for Canada's natural gas industry.

Liquefied Natural Gas (LNG) Investment Team

As the first action to implement NGAP's advice related to market access, in December 2018, the Government of Alberta established a Liquefied Natural Gas (LNG) Investment Team to work directly with industry on reducing barriers for securing final investment decisions on export projects that will increase the value of Alberta's natural gas resources. The LNG Investment Team engaged key industry members and other stakeholders to identify next steps on export projects that will source and increase the value of Alberta's natural gas resources. The LNG Investment Team gathered input from these stakeholders and submitted their advice to the minister in March 2019.

Additional Items of Note

Alberta's Royalty System Transparency and Performance

In 2018-19, the ministry continued to track and report on the royalty system in Alberta. The reporting helps Albertans examine energy industry trends in the province and the benefits that industry generates for Alberta in comparison with other jurisdictions.

Read more about Alberta's royalty framework at <https://www.alberta.ca/albertas-royalty-framework.aspx>.

Carbon Capture and Storage

The government committed \$1.24 billion dollars through to the end of 2025 to two carbon capture and storage projects: The Quest and Alberta Carbon Trunk Line projects. Combined, these two projects will capture approximately 2.76 million tonnes of carbon dioxide annually. This is roughly equivalent to the 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 Shell Scotford Upgrader and permanently storing it underground in a deep saline aquifer.

The Alberta Carbon Trunk Line project experienced delays in arranging the final stages of project financing. All required financing arrangements for the project are now complete, construction is underway and the project is scheduled to achieve commercial operation in late 2019. Once operational, the Alberta Carbon Trunk Line project is anticipated to capture approximately 1.68 million tonnes of carbon dioxide annually from the Nutrien Inc. fertilizer plant and the Sturgeon Refinery. Captured carbon dioxide will be transported through a 240 kilometre pipeline – currently under construction – to be utilized and

permanently stored as part of enhanced oil recovery operations near Clive, Alberta. The pipeline has been designed to transport up to 14.6 million tonnes of carbon dioxide annually.

Throughout the year, the department continued to monitor, administer and ensure compliance under the Carbon Capture and Storage 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 three 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 2018-19, the department continued to help guide the development of a Monitoring, Measurement and Verification Plan for the Alberta Carbon Trunk Line by Enhance Energy Inc. The department also initiated a review of the current Post-closure Stewardship Fund rate.

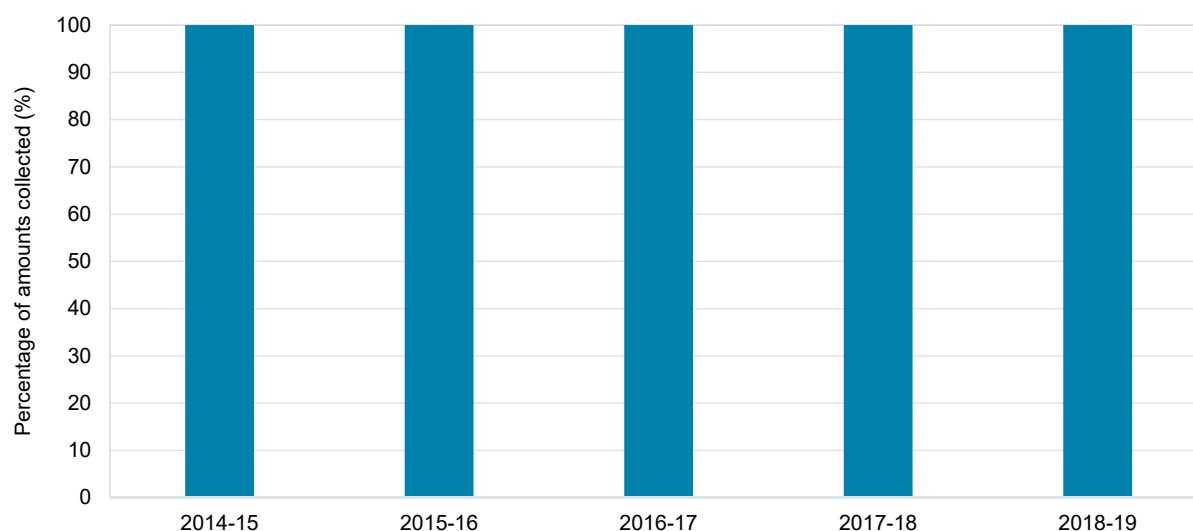
After a thorough review, the department agreed to Enhance Energy's request to assign some of its interest in the Carbon Capture and Storage Funding Agreement for the Alberta Carbon Trunk Line to Wolf Carbon Solutions Inc. The company will construct, own and operate the carbon dioxide capture and pipeline transportation assets.

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 1a: Revenues from oil, oil sands, gas, land sales and bonuses are fully collected. Percentage of amounts collected compared to owed.

Target: 100 per cent of amounts owed are collected.

Revenue from Oil, Oil Sands, Gas and Land Sales and Bonuses



Source: Ministry of Energy

Discussion of Results

One of the Department of Energy's mandates is to collect the Crown's share of energy resources on behalf of Albertans. This performance measure supports this mandate by gauging the ability of the department to collect the amounts owed through the development of Alberta's resources.

The department requires all royalty to be calculated and paid in cash or delivered in kind by a prescribed due date. Systems and processes are in place to collect royalties and to identify and follow up expeditiously on overdue accounts. Processes are also in place to collect overdue accounts and related interest and penalties.

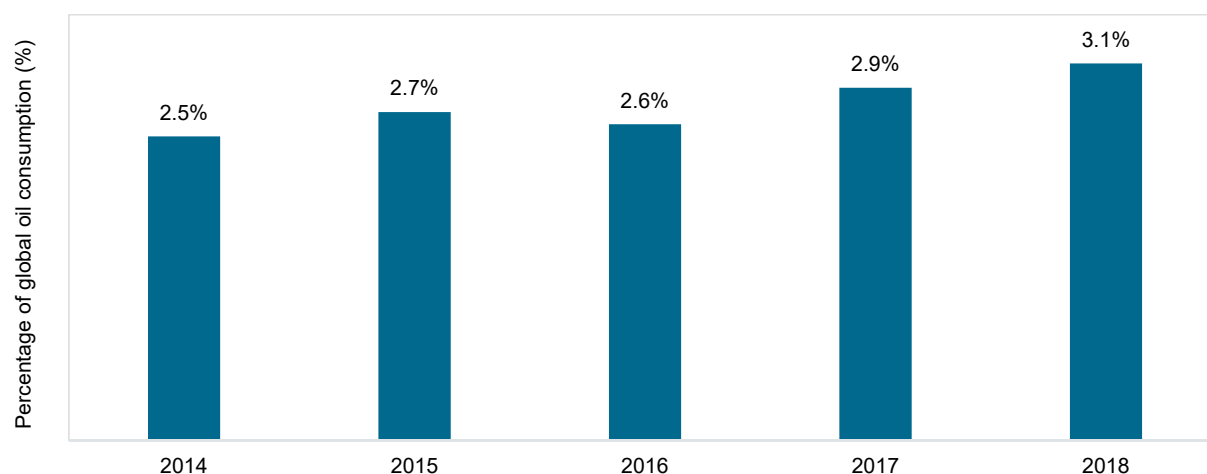
The results reported in this measure are based on financial obligations in which there are no disputes between the Government of Alberta and entities owing funds to the Government of Alberta. In the latter case, disputed amounts are excluded from the results until all outstanding matters are resolved. Upon resolution, historical results are reviewed and, if necessary, retroactively adjusted.

During the year, all amounts have been or are in the process of being collected, and no write-offs have been made. For this annual report, the revenue collection measure result was 100 per cent.

Performance Measure 1b: Alberta's oil sands supply share of global oil consumption.

Target: 2.8 per cent of global oil consumption is supplied by Alberta's oil sands.

Alberta's Oil Sands Supply Share of Global Oil Consumption



Sources: Alberta Energy Regulator; International Energy Agency

Discussion of Results

The measure was created in 2011, and introduced for the first time in the 2012-15 Energy Business Plan. This is a measure of global energy competitiveness; an increasing share is an indication of the long-run investment competitiveness relative to other global opportunities. 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 oil sands industry in Alberta has been significantly affected by the decline in the oil prices that got underway in late 2014. Oil prices significantly declined in late 2014, and remained relatively low throughout 2015 and 2016. In September 2014, the West Texas Intermediate (WTI) price was US\$93.03 per barrel (bbl) while in December 2014 it was US\$59.29/bbl. The average annual WTI price declined from US\$93.00/bbl in 2014 to US\$48.79 in 2015. In 2016, the average annual WTI price further declined to US\$43.32/bbl. The price moderately recovered in 2017 to US\$50.95, and further increased to US\$64.74 in 2018, reaching the highest annual level since 2014.

Overall, total crude bitumen production in Alberta increased by about 7.5 per cent from 2017 to 2018, from about 2.83 million barrels per day (bbl/d) to about 3.05 million bbl/d. The year-over-year increase in bitumen production was driven by the increase in the mined production, which went up by about 15 per cent from 2017 to 2018. According to the Alberta Energy Regulator, an increase in mined bitumen production from 2017 to 2018 was largely due to an increase in production from Suncor Energy's Fort Hills mine, Imperial Oil's Kearl mine and the Canadian Natural Resources Limited's Horizon and the Athabasca Oil Sands Project mines. A number of in-situ projects continued to ramp up production in

2018; the overall in-situ production went up by about one per cent from 2017 to 2018. In 2018, mined and in-situ bitumen production was about 1.47 million bbl/d and 1.57 million bbl/d, respectively. From 2017 to 2018, the share of mined production within the province's total crude bitumen production profile went up from 45 per cent to 48 per cent, while the share of in-situ bitumen went down from 55 per cent to 52 per cent.

The 2018 performance measure result of 3.1 per cent exceeded the 2018 target of 2.8 per cent, and was also higher than the 2017 actual result of 2.9 per cent. The rate of Alberta's crude bitumen production increase from 2017 to 2018 was significantly larger than the rate of global year-over-year consumption increase, which went up by 1.3 per cent during this time period. Total global oil consumption increased from 97.9 million bbl/d in 2017 to 99.2 million bbl/d in 2018. While the growth rate of Alberta's total crude bitumen production from 2017 to 2018 was lower than the growth rate of 11.6 per cent that took place from 2016 to 2017, the growth rate of global oil consumption also slowed down during this time period; global oil consumption increased by 1.6 per cent from 2016 to 2017, a faster rate than the rate achieved over the 2017-18 period.

In addition to the fact that Alberta's bitumen production growth significantly exceeded the growth in global oil consumption over the 2017-18 period, another reason for the difference between the target and the result was that the target of 2.8 per cent was based on the 2016 result for the measure, which was 2.6 per cent. The 2016 year was challenging for the oil sands industry. In addition to the relatively low price environment, the industry was also affected by the Fort McMurray wildfires. Since the production disruptions that took place in 2016 were due to Fort McMurray wildfires, they did not represent a negative overall industry trend. The fact that the target for 2018 was established on the basis of a year which witnessed uncharacteristic production disruptions has contributed to a 0.3 per cent difference between a target and an actual result in 2018.

Outcome Two

Effective stewardship and regulation of Alberta's energy and mineral resources.

The ministry engages with all stakeholders on issues involving responsible resource development of Alberta's energy and mineral resources. A strategic and integrated system approach to responsible resource development strengthens the overall environmental, economic and social outcomes for the benefit of Albertans and demonstrates the province's commitment to addressing climate change. Through its policy work with the Alberta Energy Regulator (AER), the ministry collaborates with other ministries to regulate Alberta's energy industry to ensure the efficient, safe, orderly and environmentally responsible development of energy resources. Through the Alberta Utilities Commission (AUC), the ministry further supports the interests of Albertans by ensuring that the delivery and regulation of Alberta's utility service is fair and responsible.

Key Strategies

2.1 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, and promote a positive legacy from non-renewable resource development.

Integrated Resource Management

The Government of Alberta approaches natural resource management from an integrated and systems approach. Cumulative impacts of activities are examined in relation to economic, environmental and social interests. Through the Government of Alberta's Integrated Resource Management System (IRMS), ministries work together to responsibly manage the province's resources.

The Ministry of Energy recognizes that decisions on energy resource development requires careful consideration of economic, environmental and social outcomes, and that consultation and engagement are key to mitigating risks. The ministry enhanced capacity in these areas by establishing an Engaging Communities Practice Group, collaborating with other ministries through IRMS and conducting engagement sessions with Indigenous communities, industry participants and other stakeholders.

Indigenous Community Relations

The Ministry of Energy is committed to strengthening the ministry's relationships with Indigenous communities to support responsible energy resource access, development and market access.

This past year, the Department of Energy received treaty teachings in a pipe ceremony led by elders to help ground the department's work. This was done to support the ongoing process of reconciliation, and to develop and maintain relationships with Indigenous peoples in Alberta.

Liability Management

Liability management is about improving the management of the financial and environmental liabilities associated with upstream oil and gas development while maintaining Alberta's status as a competitive place to invest. The Ministry of Energy is committed to ensuring that the liabilities associated with energy development are managed, without discouraging new investment.

Managing liabilities is an inevitable part of responsibly developing our natural resources. During the worst economic downturn in more than a generation, Alberta's oil and gas industry has demonstrated its resilience and has managed a growing number of orphan sites, insolvencies, and low oil and gas prices. While Alberta waits for pipelines to access world prices for its products, the pressure on Alberta's producers will continue, and Alberta's oil and gas industry – and Albertans – are up to the challenge.

This past year, the ministry worked with the Ministry of Environment and Parks on improvements to the liability management system.

With the help of industry, AER developed an area-based closure program that encourages companies and service companies to work together and openly share best practices and technology and provide early identification of closure work that will be conducted to facilitate collaboration. This resulted in more timely decommissioning and reclamation of energy sites, lower liabilities, and greater cost savings. For example, recent pilot projects resulted in an estimated cost savings of 10 to 40 per cent, and the closure work was conducted to a high standard and in less time.

In 2016 and 2017, the Alberta Court of Queen's Bench and the Alberta Court of Appeal rendered decisions in the case of Redwater Energy Corp., which was subsequently appealed to the Supreme Court of Canada. In January 2019, the Supreme Court of Canada stated that federal bankruptcy laws do not provide a licence to ignore rules, and that bankrupt estates must comply with regulatory orders. While the court provided welcomed clarity, the fact remains that companies in financial difficulty are less likely to meet their end-of-life obligations.

On January 1, 2019, amendments to *Section 3.1* of the *Responsible Energy Development Act's General Regulation* came into force. It guarantees the right of local governments (municipal authority, Indian reserve or Métis settlement) to participate in AER hearings when a statement of concern has been filed.

Orphan Well Loan Program

The Government of Alberta used a \$30 million grant from the Government of Canada to cover the costs of providing a \$235 million loan to the Orphan Well Association (OWA). The loan will help the OWA address the growing inventory of orphaned sites, while creating jobs in the oilfield and environmental service sectors and maintaining the polluter pays principle.

Repayment of the loan began January 1, 2019 and is funded through the existing orphan fund levy paid by industry and managed on OWA's behalf by AER. Within fiscal 2018-19, \$100 million was advanced to the OWA.

To learn more about OWA's work on managing the province's orphan wells and to read the association's annual report, visit: www.orphanwell.ca.

Caribou Range Planning

Government supported the development of caribou range plans in response to the Government of Canada's requirements in October 2017 under the Species at Risk Act. The Ministry of Energy supported the Ministry of Environment and Parks in caribou range planning. The restrictions on tenure sales in caribou ranges and availability of extensions for agreements within a caribou range when circumstances prevented the continuation or validation of the agreement created time and space for range planning and ensured that Alberta's responsibilities to manage species at risk were carried out in a balanced way.

Moose Lake Special Management Zone Plan

The ministry represented energy interests with the development of the Ministry of Environment and Parks Draft Moose Lake Access Special Management Zone Plan. This cross-ministry collaboration supported the effective stewardship and regulation of Alberta's energy and mineral resources under the Lower Athabasca Regional Plan while honouring Treaty Rights.

Conservation Area Planning and Implementation

The Ministry of Energy, along with other IRMS partners provided input into the Ministry of Environment and Parks to develop three land use planning proposals in 2018-19.

The ministry continued implementation of conservation areas designated under the South Saskatchewan Regional Plan, and is in the process of cancelling portions of 10 metallic and industrial minerals agreements that fell within the boundaries of the Bow Valley, High Rock, and Castle wildland provincial parks and Castle Provincial Park. Managing competing priorities for conservation of lands while ensuring reasonable access for energy and mineral development continued to be a challenge in 2018-19. Strong, open and collaborative cross-ministry relationships and ongoing engagement with affected operators served as an effective way to understand issues towards the development of balanced approaches.

2.2 Optimize regulation and oversight to ensure the safe, efficient, effective, credible and environmentally responsible development of Alberta's energy resources.

Enhancing the oil and gas regulatory system for efficiency and improved response

The Ministry of Energy, in conjunction with the AER and the Ministry of Environment and Parks, continued to work in partnership with industry to improve the regulatory efficiency for the oil and gas industry in the province. Industry has a keen interest in improvements to Alberta's regulatory system. Discussion with industry and analysis served to identify additional ways to improve regulatory efficiency.

The energy development landscape in Alberta continues to change rapidly, driven by economic circumstances, technology, and changing expectations and the AER continued to adapt to these changes. As the AER works to deliver on its mandate and vision, many initiatives are considered for the benefit they have for all Albertans. During 2018-19, AER continued to work to assess these for value and risk exposure, through a deliberate approach to deliver on all aspects of its mandate and ensure that regulatory oversight is effective in its regulatory delivery while being cost effective. The AER is committed to improve its review of results and performance in an effort to learn, and to provide more transparency to the public about the regulation of energy development activities, hold operators accountable for their actions and work with industry to improve its performance. In October 2018, the AER published updated application processing timelines as part of its work to improve efficiency and help make Alberta more competitive.

The AER continued to focus on effective management of public safety and environmental risks and the management of resource conservation and minimized financial liability on Albertans. This included sustainable water use, reduced fluid tailings accumulation over mine life, reduced methane emissions, reduction of aging inventory, and pipeline safety with a focus on reducing high-consequence pipeline incidents. In addition to taking enforcement actions when required, the AER achieved this outcome by examining incident data, adopting a risk-based approach and by enhancing the investigation process.

Water Reporting for Sustainable Water Use

In May 2017, the AER began reporting company-specific information on the amount of water used for in-situ, mining, hydraulic fracturing and enhanced oil recovery operations. This report is updated annually and provides contextual information concerning the major drivers of water use during energy extraction within each of the sectors mentioned above. It reports the amount of water available and allocated at the provincial and water shed levels within the province as well as each company's water use intensity per barrel of oil equivalent produced.

Tailings Management

The AER published all decisions to tailing management plans on its website. The first State of Fluid Tailings Management for Minable Oil Sands report was published September 2018. The report is updated annually and summarizes information submitted by oil sands operators in their annual tailings management reports to ensure that these submissions adhere to the requirements of *Directive 085; Fluid Tailings Management for Oil Sands Mining Projects* and the conditions in each operator's tailings approvals. The report includes a summary of:

- Fluid tailings volumes at both a regional level and for each individual operation;
- Treated fluid tailings volumes for each operator by treatment technology;
- Fluid tailings treatment operations and continuous improvement for each operator; and
- Technological innovation in fluid tailings treatment for each operator.

Pipeline Safety

The AER ensured integrity for pipeline infrastructure in a way that reduces risk and ensures Albertans reap the economic rewards of energy resource. The AER inspects pipeline operations regularly to ensure that companies are meeting the requirements and are monitoring for potential risks. AER's inspections consider the risks of individual pipelines, and pipelines with greater risks receive more scrutiny. The AER has also implemented an assessment program to evaluate the effectiveness of pipeline licensees' safety and loss management systems. The program aims to ensure that adequate systems have been implemented, which will result in fewer pipeline incidents and greater licensee accountability. The number of high consequence pipeline incidents was 23 in 2018-19, 24 in 2017-18, and 30 in 2016-17.

Integrated Decision Approach (IDA)

The Ministry of Energy collaborated with the AER to develop policies to support the full implementation of the Integrated Decision Approach (IDA). Using a new technology known as One Stop, the AER began to implement the IDA for energy development in 2018-19. IDA is based on the concept of one application, one review, and one decision, and is applicable across the life cycle of energy development. Enhancements were made to pipeline licencing in 2018-19 along with the start of the public land authorizations and well licencing projects. This supports 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.

Regulatory Compliance

The AER initially established this indicator based on data compiled during the transition to a new Compliance Assurance Framework which better reflected its new authorities and mandate. This indicator reports the percentage of inspections conducted that are in compliance with regulatory requirements.

In 2018-19, the AER conducted 10,520 field-based initial inspections, in which 10,401 of those inspections resulted in a finding of compliance. The inspections resulted in the issuance of 119 enforcement actions, which is comprised of the following:

- 92 suspensions;
- four warning letters;
- seven administrative penalties;
- one administrative sanction;
- 13 orders; and
- two prosecutions.

The 2018-19 results are within the expected range of compliance and demonstrate progress toward the desired outcome of ensuring industry compliance with regulatory requirements.

Regulatory Compliance Rates

Percentage of inspections resulting in a finding of compliance

- 2016-17: 99 per cent
- 2017-18: 99 per cent
- 2018-19: 99 per cent

Factors like changing market conditions, changing political climates, increased insolvency, incidents, and other PESTLE (political, economic, social, technological, legal, and environmental) factors make it difficult to attain 100 per cent compliance.

Inspections are selected based on an enterprise management approach to defining and applying risk as well as the predetermined level of risk that the activity may pose to public safety, the environment, resource conservation, and stakeholder confidence in the regulatory process, including public and political influences. The AER places higher priority on reactive work, such as responding to releases and complaints. The amount of reactive inspection work can significantly impact the reported result for this measure because the nature of the work is unplanned and has a high chance of resulting in compliance action and because, less time will be spent conducting proactive compliance activities.

AER's requirements and inspection and audit programs ensure that the verification of compliance is done in a way that protects the environment and public safety. By sharing AER investigation reports externally companies have the opportunity to learn the root cause of situations and improve their practices. Continuing to meeting with companies that historically have had poor performance and publicly sharing the Pipeline Industry Performance Report and Water Use Industry Performance report allows companies to understand how they measure up. Additionally the AER works with companies years in advance to help manage energy development to make sure they are prepared to meet their obligations at the end of a project's life. Internally, AER continued to prioritize staff training to align with its high priority inspection and audit areas and continue to enhance its industry education program.

AER continued 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.

Indigenous Engagement at AER

The AER has identified as one of its strategic goals that the regulation of Alberta's energy resources is improved by actively engaging Indigenous peoples, stakeholders and the public. To advance the AER toward a future-state where AER's relationship with Indigenous peoples is one of mutual trust and respect, the AER has begun an assessment of its engagement with Indigenous communities. This assessment includes how the AER can best work with other Government of Alberta ministries with a focus on efficiency and improving working relationships with Indigenous communities.

The cost of AER's activities in 2018-19 was \$259 million and was fully funded by industry levies.

2.3 Enhance regulation and oversight of Alberta's utilities to ensure social, economic and environmental interests of Alberta are protected.

AUC Compliance Audits

The current *Code of Conduct Regulation* came into effect January 1, 2016 and requires audits to be performed for all distributors, regulated rate suppliers and affiliated providers (related competitive retailers) at least once every 36 months. Under the *Code of Conduct Regulation*, the AUC has jurisdiction for code of conduct matters for electricity entities and gas entities and plays a central role in ensuring compliance with the regulation. Fulfilling the audit requirements as outlined in the regulation further enhances the AUC's oversight of Alberta's utilities. The commission completed audits of three large entities (i.e., ATCO group, Direct Energy and EPCOR group consisting of eight separate audits) by December 31, 2018. The results of these audits confirmed that these large entities are meeting the requirements of the *Code of Conduct Regulation* (i.e., no contraventions). With the completion of these audits, the commission intends to lead audit execution of smaller Rural Electrification Associations in fiscal 2019-20.

In addition, the AUC relaunched its compliance assessment program targeting minor transmission facilities in 2018, building on the positive outcome from the initial compliance review in 2016. The commission's objective was to assess whether transmission facility owners are fulfilling the requirements set out by the commission for minor transmission facilities to mitigate any social, environmental and cost issues occurring as a result of these projects. No major issues were identified in the commission's compliance assessment targeting minor transmission facilities.

Electric Distribution System Inquiry

In late 2018, the AUC launched the Electric Distribution System Inquiry. The evolving nature of electric generation, consumption, storage and the system has significant implications for the grid, incumbent utilities, consumers, grid managers and the regulatory framework. These are among the central matters the AUC will examine in its distribution inquiry.

For the AUC, the changing energy system raises fundamental questions about traditional planning approaches, rate structures, cost-recovery mechanisms, incentives and the evaluation of prudent utility costs.

The commission expects that advancements in distributed energy resources and smart technologies will require a proactive approach to regulation. Understanding the convergence of information and operational technology in the distribution grid is fundamental in determining what types of investments will facilitate the alignment of distributed resources and changing consumption patterns to ensure the continued provision of reliable service at reasonable rates.

The commission also recognizes that the prospect of technology adoption raises questions about the current distribution system business model, and whether alternative models will be required to enable incumbent utilities to absorb the potential risk of significant distributed energy resource deployments.

Finally, a key issue for the commission, given its mandate, is whether the current approach to rates and rate design needs to be re-evaluated in light of new technology advances and market entry of new and non-traditional participants providing alternative technology.

Given these demands, the results of this inquiry will assist the commission in charting the regulatory agenda in the foreseeable future to effectively and efficiently achieve its mandate. The inquiry is currently in the preliminary planning phase.

The cost of AUC's activities in 2018-19 was \$32 million and was fully funded by industry.

2.4 Collaborate with the Alberta Climate Change Office and other ministries to develop and implement regulatory standards as part of Alberta's Climate Leadership Plan to reduce greenhouse gas emissions by:

- **Reducing methane levels for the upstream oil and gas sector by 45 per cent from 2014 levels by 2025; and**
- **Limiting emissions from oil sands development.**

Methane Emissions Reduction Regulation

Throughout 2018-19, the Ministry of Energy led a multi-stakeholder approach in the development of regulatory standards on methane emission abatement. Draft AER methane directives were released for public comment in April 2018 and 119 respondents provided unique feedback, which were considered in the development of the new requirements.

Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting and Directive 017: Measurement Requirements for Oil and Gas Operations – collectively known as Alberta's methane regulations - were published on the AER website in December 2018. The directives will come into force starting January 1, 2020 with the mandated check-in point of 2023 to ensure the 45 per cent reduction target is met.

In 2018-19, the Ministry of Energy also developed Alberta's *Methane Emission Reduction Regulation* in collaboration with the Ministry of Alberta Environment and Parks to aid the achievement of federal equivalency on methane emission requirements. The regulation was authorized in early December 2018 and will take effect January 1, 2020.

The ministry also led the negotiation for an equivalency agreement with Environment and Climate Change Canada (ECCC). Despite challenges from ECCC accepting equivalency continued as differing modelling approaches, methodologies, data and assumptions used by Alberta and along with Ministry of

Environment and Parks, the ministry collaboratively provided ECCC with necessary information supporting the federal modelling exercise.

Oil Sands Emissions Limit

The *Oil Sands Emissions Limit Act* came into force December 2016 and legislates the annual 100-megatonne greenhouse gas limit on oil sands emissions, sets the scope of facilities included, enables allowable exclusions for new upgrading and cogeneration emissions, and grants authority to develop regulations. The cap increases the incentive to drive technological progress while ensuring Alberta's operators have the necessary time to develop and implement new technology to reduce the carbon output per barrel helping drive reductions in Alberta's overall emissions trajectory.

The *Oil Sands Emissions Limit Act* serves as an enabling legislative framework, however, the *Carbon Competitiveness Incentive Regulation* paired with innovation fund programs serve as the primary management approach for oil sands greenhouse gas emissions.

The Ministry of Energy supported the Ministry of Environment and Parks' work on developing policy options for the *Oil Sands Emissions Limit Regulation* for the implementation of the 100-megatonne oil sands emissions limit. The Ministry of Energy coordinated work on preparing a long-term forecast of oil sands production and associated greenhouse gas emissions and continued to update the forecast utilizing the most up-to-date and verifiable information from the oil sands sector. The Ministry of Energy's initial emissions forecasting showed that emissions are not expected to exceed the 100-megatonne limit before 2030.

The ministry recommended that emissions from refineries and stand-alone gas fractionating plants in Alberta be excluded from the 100-megatonne limit and treat partial upgrading emissions as new or expanded upgrading capacity emissions. The *Oil Sands Emissions Limit Act* enables government to create an exclusion for up to 10 megatonnes for new or expanded upgrading capacity emissions.

The Ministry of Energy reiterated a strong preference for mechanisms and protocols that provide early, clear and easily discernible signals to all stakeholders regarding emissions thresholds at which actions will be taken and potential compliance mechanisms will be initiated. Design and implementation of the 100-megatonne oil sands emissions limit was put on hold in the fourth quarter of 2018, as the Government of Alberta assessed impacts of several initiatives by the federal government, including the proposed *Impact Assessment Act* (Bill C-69).

Additional Items of Note

Regulatory Amendments

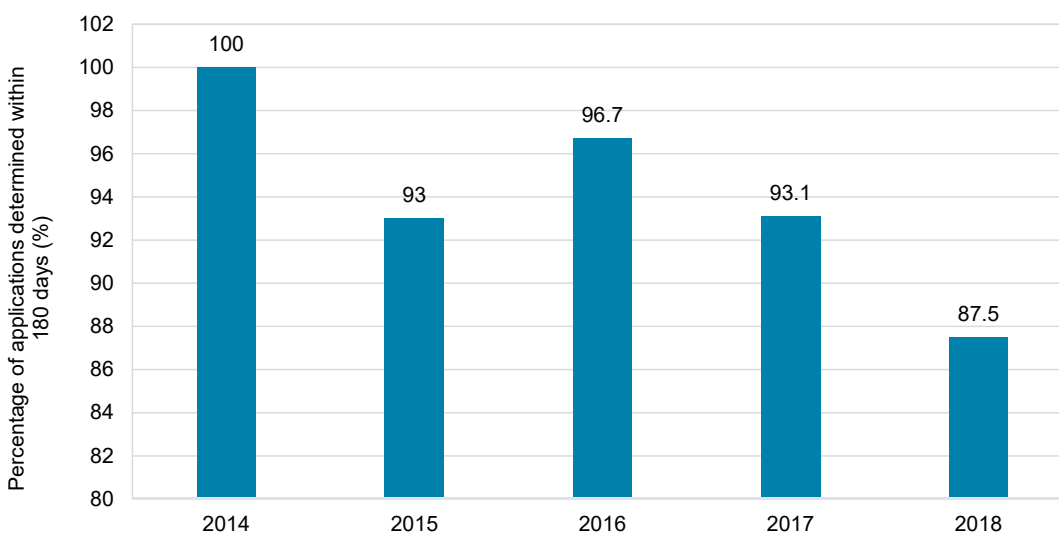
In 2018-19, the Ministry of Energy amended regulations and renewed expiring regulations. It is important that all regulations under the mandate of the Ministry of Energy are up to date in terms of expiries and administrative changes are completed on a timely basis. The following list of regulations with expiry dates of 2018 and 2019 were either approved for renewal or expiry:

- *Natural Gas Royalty Regulation, 2009*
- *Oil Sands Royalty Regulation, 1997*
- *Crown Minerals Registration Regulation*
- *Petroleum Marketing Regulation*
- *The Innovative Energy Technologies Regulation*

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

Target: 100 per cent of needs and facility applications determined within 180 days of the application being deemed complete.

Timeliness of Needs and Facility Applications



Source: Alberta Utilities Commission

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 2018, the AUC met the target 87.5 per cent of the time as 35 of 40 decisions were issued within the 180-day timeline. The decisions that missed the 180-day deadline addressed novel, complex issues. The applications were contested by interveners and processing time was extended to address procedural motions. Further, because of the complexity of the issues raised, the AUC employed written argument rather than oral argument which further extended processing time.

Compared to recent years, the scope and nature of interventions on transmission need proceedings increased in 2018. In particular, intervener groups are challenging the Alberta Electric System Operator's (AESO) generation and load forecasts and planning assumptions as well as its transmission alternatives to a much greater degree than in the past. The AUC has seen a rise in procedural motions which lead to additional processing time. In 2018, the AUC saw a rise in requests by participants (applicants and interveners) to conduct argument in writing rather than orally. The use of written argument can considerably extend processing time for a proceeding. For example, it added 20 days to the AESO Provost need proceeding, 28 days to the Stirling wind project hearing and 62 days to the AESO PENV need hearing.

Outcome Three

Albertans benefit from a stable, reliable electricity system that protects consumers, attracts investment, and has improved environmental performance.

An electricity system that has reasonable prices, reduces emissions from coal-fired electricity, and creates a positive investment climate is vital to the social and economic foundation of Alberta. Alberta requires a modern electricity system to support the transition to a cleaner energy future and meet the needs of a growing province. The Ministry of Energy collaborates with other ministries, agencies, stakeholders, and Indigenous communities to develop and deliver effective electricity system policies and programs.

Key Strategies

The ministry undertook many initiatives in 2018-19 to move towards a stable, reliable electricity system that protects consumers, attracts investment, and improves environmental performance.

Bill 13: An Act to Secure Alberta's Electricity Future was passed in the legislature in June 2018. This legislation:

- Established and enabled the capacity market;
- Clarified duties, expectations and responsibilities of electricity agencies and market participants;
- Enhanced public interest oversight by requiring all electricity rules to undergo review and approval by the Alberta Utilities Commission (AUC); and
- Ensured clear and mandated requirements for stakeholder involvement in the design and operation of Alberta's electricity markets.

3.1 Collaborate with other ministries to implement recommendations and manage regulatory requirements from Alberta's Climate Leadership Plan to transition Alberta's electricity system to a lower carbon system, including:

- **Implementing a plan to phase out coal fired electricity generation by 2030; and**
- **Delivering on Alberta's commitment of 30 per cent electricity production from renewables by 2030.**

Renewable Electricity Program

On November 3, 2016, the Government of Alberta announced the Renewable Electricity Program (REP) to increase the use of renewable electricity such as wind, solar, geothermal, sustainable biomass and hydro.

The first three auctions secured a total of 1,360 megawatts of new renewables.

The first competition for REP began in March 2017, with investors bidding to provide up to 400 megawatts of renewable electricity over a 20-year contract term. On December 13, 2017, the Alberta Electric System Operator (AESO) announced it would procure nearly 600 megawatts of wind from four projects to be built and operational by the end of 2019.

The second and third REP competitions began in March 2018. REP Round Two was designed to include a minimum 25 per cent Indigenous equity ownership component to encourage participation by Indigenous communities, create the greatest degree of competition, and provide the lowest cost for Albertans. REP Round Three maintained many of the features of REP Round One. The results of REP Rounds Two and Three were announced on December 17, 2018. The five successful projects are expected to generate a total of 760 megawatts of renewable electricity at an average weighted price of 3.9 cents per kilowatt hour.

Renewable Electricity Program Status: 1,360 megawatts secured through three rounds of bidding

Round One (December 2017)

- Capital Power, an Alberta-based company will build the 201-megawatt wind project 60 kilometres southwest of Medicine Hat.
- EDP Renewables Canada Ltd. will build a 248-megawatt wind farm at their Sharp Hills project east of Hanna, roughly 50 kilometres north of Oyen.
- Enel Green Power North America, Inc. will build two projects – a 115-megawatt Riverview Wind Farm and a 31-megawatt Phase 2 of Castle Rock Ridge Wind Power Plant just outside of Pincher Creek.
- Projects are expected to be operational by the end of 2019.

Round Two (December 2018)

- EDF Renewables Canada Inc., which will build the 201.6-megawatt CypressWind Power project in Medicine Hat.
- Potentia Renewables Inc., which will build the 113-megawatt CypressWind Power project in Lethbridge.
- Capstone Infrastructure Corporation, which will build three wind projects in Brooks:
 - 17.25-megawatt, Buffalo Atlee Wind Farm 1.
 - 13.8-megawatt, Buffalo Atlee Wind Farm 2.
 - 17.25-megawatt, Buffalo Atlee Wind Farm 3.
- Projects are expected to be operational in 2021.

Round Three (December 2018)

- TransAlta Corporation, which will build the 207-megawatt Windrise Wind project in Pincher Creek.
- Potentia Renewables Inc., which will build two wind projects in Brooks:
 - 122.4-megawatt, Jenner Wind Power Project.
 - 71.4-megawatt, Jenner Wind Power Project 2.
- Projects are expected to be operational in 2021.

Coal Transition

On November 24, 2016, the province reached agreements with the three coal-fired generators that owned units expected to operate beyond 2030. The coal-fired generation units covered under the agreements include: Sheerness 1 and 2; Genesee 1, 2, and 3; and Keephills 3.

As part of the off-coal agreements, companies agreed to eliminate emissions from their generating units by 2030, and the province agreed to make voluntary transition payments of \$97 million annually to the three generators until 2030. The agreements ensure the companies spend a specific amount every year to support communities, employ a minimum number of people in the province, keep their head offices in Alberta and continue to invest in Alberta's electricity system.

The Ministry of Energy supported coal community and worker support initiatives led by the Ministry of Economic Development, Trade and Tourism, and the Ministry of Labour and Immigration, as well as the federal government. In 2017, the Coal Community Transition Fund was released, supporting 12 projects in 17 coal impacted communities with total funding of approximately \$5 million to explore economic development options.

Coal-to-Gas

Natural gas is abundant in Alberta, with low-cost production available, making coal-to-gas conversions a viable cleaner alternative to coal-fired electricity generation. In comparison to new natural gas combined cycle plants, coal-to-gas conversions have significantly lower capital costs. Coal-to-gas conversions could save capital while providing an immediate reduction in carbon dioxide emissions, sulfur dioxides, lead and other pollutants from the existing coal fleet.

In 2018-19, the Government of Alberta examined the current and emerging policy framework for coal-to-gas conversions both provincially and federally, with the goal of providing clarity and removing unnecessary barriers to allow companies to make informed decisions as to whether or not to convert their existing coal units to natural gas.

The Ministry of Energy supported the Ministry of Environment and Parks in its engagement of the federal government on proposed greenhouse gas emission standards for coal and natural gas generation and the draft Clean Fuel Standard.

On October 23, 2018 the federal government released its proposed Output-Based Pricing System, which included differentiated fuel-specific standards for the electricity sector. This regulation will apply to provinces that do not have an equivalent or more stringent system.

On December 20, 2018 the federal government released draft regulations, including an update to the standard that will apply to coal and coal-to-gas converted units.

Dispatchable Renewables and Energy Storage

Dispatchable renewables and energy storage have the potential to play a role in Alberta's electricity system, especially with increased penetration of intermittent renewable generation such as solar and wind. Government reviewed the policy and legislative framework that impacts the ability of these technologies to enter the electricity system, including unintended or unnecessary policy or legislative barriers.

AESO presented a report to government on May 31, 2018, assessing if dispatchable renewables and energy storage are needed to continue to deliver a reliable electricity system out to 2030, and if needed,

how they should be procured. The Department of Energy accepted its recommendation that a specific procurement for dispatchable renewables and energy storage is not needed at this time. AESO posted the report on their website on September 25, 2018 and presented the results to stakeholders on October 3, 2018. The report can be found at <https://www.aeso.ca/assets/Uploads/AESO-Dispatchable-Renewables-Storage-Report-May2018.pdf>.

A complex mix of factors such as relatively low wholesale electricity prices, relatively cheap and abundant natural gas supply, and regulatory and policy uncertainty at the federal level with respect to issues such as the federal Clean Fuel Standards and Bill C-69 has resulted in a complex environment in which corporate decisions relating to electricity and energy sector investment decisions can be difficult to predict.

Community Generation

A cross-ministry initiative between the Ministry of Energy, Ministry of Environment and Parks, and the Ministry of Economic Development, Trade and Tourism was necessary to ensure the strategic integration and alignment of initiatives, programs and policies across the Government of Alberta to advance community generation.

Community generation refers to a subset of small-scale generation that provides benefits to communities, such as training, environmental protection or economic development opportunities, and distinguishes it from other types of small-scale generation. Small-scale generation refers to electricity generated from renewable or alternative sources connected to the distribution system.

As part of *An Act to Secure Alberta's Electricity Future*, the *Electric Utilities Act* was amended to allow the Minister of Energy to create small-scale generation regulations in Alberta. A new regulation, the *Small Scale Generation Regulation*, enabling small scale and community generation, came into force on January 1, 2019. This regulation enables a range of generation projects by reducing regulatory, technical, and financial barriers for small-scale and community generation within Alberta's existing framework for electricity generation.

Geothermal Energy

Geothermal energy is the natural heat that originates from the Earth that can be extracted from the subsurface using different technologies. Geothermal energy has potential applications for direct uses (such as district or community heating) and indirect uses (such as electricity generation), or in support of other economic sectors such as agriculture, forestry, and oil and gas.

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

Through the summer 2018, the Ministry of Energy, in collaboration with Indigenous Relations and Environment and Parks, undertook targeted engagement with external stakeholders representing geothermal industry participants, oil and gas operators, environmental non-government organizations, municipal governments, private landowners and freehold mineral owners, researchers, and Indigenous communities. Stakeholder engagement was key to better understand geothermal resources in Alberta,

which helped identify key perspectives, issues, concerns and opportunities and inform the development of a provincial geothermal policy framework.

In the meantime, the Ministry of Energy continued to work in collaboration with cross-ministry and provincial agency partners to develop an interim regulatory approach where geothermal pilot and demonstration projects are in advanced stages. The ministry actively worked with proponents on a case-by-case basis to advance potential projects and identify risk-based regulatory pathways for individual projects to enter the regulatory approval process while work continued to develop a provincial policy framework.

3.2 Develop and implement policy to efficiently regulate Alberta's electricity retail system to protect consumers.

Regulated Rate Option Rate Cap

On November 22, 2016, the Government of Alberta announced the introduction of a four-year Regulated Rate Option (RRO) rate cap effective June 1, 2017. The cap was made available to all consumers on the RRO, including residential, farm, irrigation, and small commercial consumers using less than 250,000 kilowatt hour of electricity per year.

Consumers on the RRO payed the lower of the RRO or the government's rate cap of 6.8 cents per kilowatt hour. If the rate exceeded 6.8 cents per kilowatt hour, the government paid RRO providers the difference above that price. During the 2018-19 fiscal year, the rate cap was triggered nine times.

2018-19 Regulated Rate Cap Consumer Reimbursements

- Months when market rates exceeded the rate cap of 6.8 cents per kilowatt hour:
 - April 2018: \$8.7 million
 - July 2018: \$7.8 million
 - August 2018: \$11.9 million
 - September 2018: \$7 million
 - October 2018: \$0.3 million
 - November 2018: \$0.2 million
 - December 2018: \$6.6 million
 - January 2019: \$7.5 million
 - February 2019: \$2.5 million

In December 2018, amendments to the *Rate Cap (Board or Council Approved Regulated Rate Tariffs) Regulation* and the *Rate Cap (City of Medicine Hat) Regulation* were made in order to clarify reimbursement and billing rates and allow the City of Medicine Hat a longer reimbursement submission period.

Securing Alberta's Electricity Future: Penalties for Violating Commission Orders

On June 11, 2018, Bill 13: *An Act to Secure Alberta's Electricity Future* came into effect, which allowed the AUC to apply financial penalties to entities violating a commission order, rule or decision. As a result, the commission initiated the development and implementation of a specified penalties framework as contemplated in Bill 13. The ability to impose specified penalties for breach of consumer-related AUC rules ensures utility service providers, including competitive retailers, fulfill the standards of service and safety.

Following a rule review and rule development process, the AUC approved Rule 032: Specified Penalties for Contravention of AUC Rules and amendments to Rule 021: Settlement System Code Rules, Rule 028: Natural Gas Settlement System Code Rules and Rule 003: Service Standards for Energy Service Providers, with an effective date of January 1, 2019.

Through Rule 32, the AUC established a clear framework to apply financial penalties to predefined rule contraventions. The rule outlines specific factors the AUC will consider when determining specified penalties as well as the various levels of those penalties depending on the frequency of rule breaches. In addition, amendments to Rule 003 further strengthens consumer protection by prohibiting regulated companies from recovering service guarantee credits through the rates charged to other customers.

Striking a balance between practicality and fairness to industry and consumers posed a significant challenge. The AUC responded to this challenge by taking a consultative approach during its rule review and rule development process. Prior to approving Rule 032 and amending Rule 003, Rule 021 and Rule 028, the AUC engaged with key stakeholders to identify and took into consideration all relevant concerns. Stakeholder engagement and consultation continued to be a key success criteria for the commission in its efforts to efficiently regulate Alberta's electricity and natural gas retail systems to protect consumers.

3.3 Create a reliable electricity system that is affordable for Albertans and attractive to investors by implementing an electricity capacity market

Capacity Market Framework

On November 23, 2016, the government announced that Alberta would transition to a capacity market, based on recommendations from current and potential energy investors, external experts, consumer groups and AESO. The new government is now reviewing this policy.

The capacity market design process was completed in 2018-19. The Department of Energy led the policy development of the capacity market, and implemented the policy design through amendments to Alberta's electricity acts and regulations and through the creation of a new regulation specifically for the capacity market. AESO also completed the technical design of Alberta's capacity market during this time frame. The Department of Energy and AESO worked closely together throughout the design process to ensure that the policy and technical market designs are well aligned.

Approximately 385 stakeholders representing 182 organizations participated in the Ministry of Energy's policy development process for the capacity market. Stakeholders included generation, transmission, distribution and retail companies; Rural Electrification Associations; industry associations; potential investors; electricity-related non-governmental organizations; electricity agencies; and electricity consumer representatives. The stakeholder session provided input on the development of a number of electricity initiatives, including the *An Act to Secure Alberta's Electricity Future*, to amend multiple electricity regulations and the creation of a new *Capacity Market Regulation*.

All regulatory work was completed by December 2018, providing the legal foundation needed for completion of the technical design led by AESO. Both the department and AESO met the publicly stated timelines to complete the policy and technical design work by end of January 2019 to target implementation of the capacity market in 2021. The Ministry of Energy continued to monitor the implementation of the technical market design. AESO filed the first set of capacity market rules in January 2019 for review and approval by the AUC.

The design of a capacity market was an intense and technical endeavour. Close collaboration between the Department of Energy and Alberta's electricity agencies and sector stakeholders was essential to this work. Coordination of engagements led by the department and AESO was important to ensure stakeholders were able to participate in both processes.

Regulatory Oversight of the Capacity Market

On June 11, 2018, Bill 13: *An Act to Secure Alberta's Electricity Future* came into effect, enhancing the AUC's role in the development and regulatory oversight of Alberta's electricity system. Legislation now requires the AUC to review and approve all new or modified rules governing Alberta's electricity system. Previously, rules were only subject to review and approval if market participants filed specific objections to the rules. This change aligns Alberta's rule oversight process with best practices in other jurisdictions and is intended to increase the clarity, functionality, and stability of electricity system rules.

Prompted by the new legislation, the AUC reviewed, consulted on and updated its AUC Rule 017: Procedures and Process for Development of ISO Rules and Filing of ISO Rules with AUC. The intended result of this initiative was to broaden and substantiate the consultative process the AESO must apply to ensure fairness, balance and efficacy in the development of market rules. On July 24, 2018, AUC approved amendments to AUC Rule 017. As of August 1, 2018, all amendments to the *Electric Utilities Act* came into force.

In 2018-19, the AUC began to prepare to review, analyze and approve the rules submitted by AESO to shape and govern the implementation of a capacity market system. The AUC established a dedicated Capacity Markets Group to support the commission to adjudicate on matters that would facilitate this transition. Stakeholder input played a key part in the regulatory work that supported the capacity market development. Stakeholders had the opportunity to provide comments during the AUC review, with the AUC legislatively required to render decisions on the rules by July 31, 2019.

Additional Items to Note

Exploring Electricity Interties

Transmission interties with the province's neighbours enable the import and export of electricity into and out of Alberta. Interties help to maintain supply stability and resiliency in the electricity system and offer economic benefits to Alberta's electricity generators through electricity export. The Government of Alberta supported transmission interties with other jurisdictions that benefit the province.

Regional Electricity Cooperation and Strategic Infrastructure (RESOI) initiative is a Government of Canada initiative involving the governments and electric system operators from Alberta, British Columbia, Saskatchewan, Manitoba, and the Northwest Territories. Through this initiative, a Natural Resources Canada commissioned study was released in August 2018 evaluating electricity infrastructure projects in the western provinces. Intertie projects assessed as part of the study included a new Alberta-British

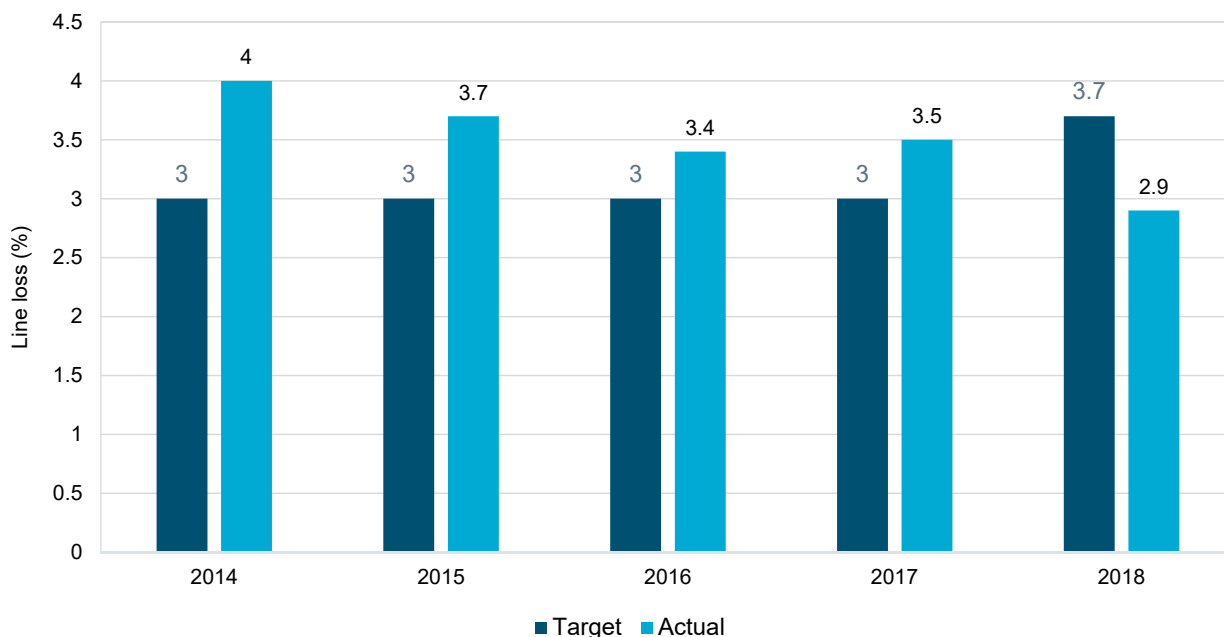
Columbia intertie, the Alberta-British Columbia intertie restoration, a new or expanded Alberta-Saskatchewan intertie, and a new Alberta-Northwest Territories intertie.

The restoration of the existing Alberta-British Columbia intertie to its full capability has an anticipated completion date of 2020-21. AESO and BC Hydro are working on this project. AESO anticipates filing a Needs Identification Document application with AUC in 2019.

Performance Measure 3a: Transmission losses

Target: To maintain a minimum level in transmission line losses. The target for 2018 was 3.7% \pm 0.3%.

Transmission Losses



Source: Alberta Electric System Operator

Discussion of Results

Electricity is a facilitator of economic development in Alberta. A reliable and resilient electricity transmission system is required to ensure electricity can be delivered where and when it is needed. By ensuring development of a robust transmission system, renewable and thermal generators will know that they will be able to efficiently move their product to market, and to consumers that depend on it daily. The transmission system has been, and continues to be, built to accommodate greater amounts of renewable energy. Existing and near-term infrastructure projects are expected to support greater amounts of renewable generation in the south and central-east regions. Generally, there is renewable energy potential throughout the province. Optimal use of power from these sources depends on our ability to bring it to where it is needed.

Transmission losses are an indicator of efficiency of the transmission system. A transmission system with adequate capacity will have lower losses than a system that requires upgrading. The hourly volumes of line losses vary based on load and export levels, the distance between generation and load, and changes in the transmission topology. Transmission and generation outage schedules, unplanned transmission and generation outages, and market dispatches also affect the volume of losses. The value of line losses is calculated on the hourly pool price.

Transmission line losses are an indicator of system efficiency and optimization. The benefits of maintaining low transmission line losses for Albertans are lower system costs, reduced wasted energy, and the environmental benefits associated with the need for less electricity generation.

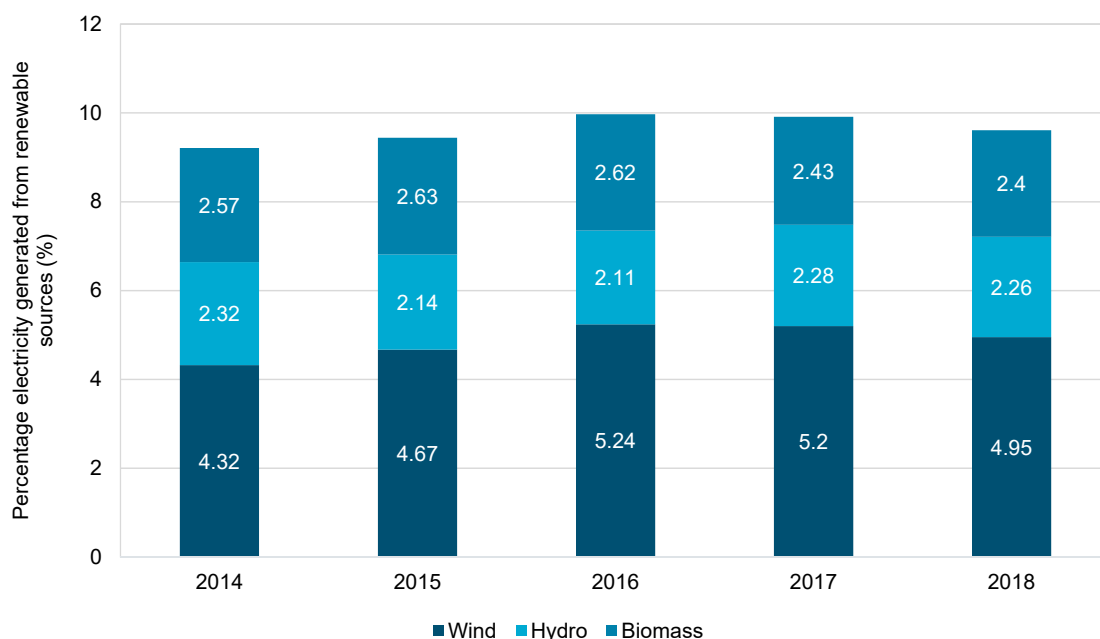
Prior to 2018, the line loss target was a qualitative target that was drawn from the transmission policy development process in 2003. At the time, the average system losses were about five per cent, and as a result, a target of three per cent was deemed reasonable.

However, starting in 2018, the methodology for calculating line loss targets was changed to reflect the five-year rolling average of prior line losses. As well, the five-year averages used data from the annual totals of the monthly loss factor customer volumes and monthly loss volumes. These line losses are calculated in AESO's Rider E Calibration Factor report for each quarter, which results in slightly higher actual line losses because both volumes use data up to the meter. In previous years, the generation volume included generation behind the meter, resulting in a lower calculated line loss value. The 2014 to 2017 actuals shown here have been updated and are based on the new methodology.

Performance Measure 3b: Percentage of electricity produced in Alberta from renewable sources (megawatts)

Target: 30% of electricity generation from renewable sources by 2030

Renewable Electricity Generation



Source: Alberta Utilities Commission

Note: Totals may not add up due to rounding

Discussion of Results

The *Renewable Electricity Act* established the target that by 2030 at least 30 per cent of the electric energy produced in Alberta, measured on an annual basis, will be produced from renewable energy resources.

Under the *Renewable Energy Act*, renewable energy resource means an energy resource that occurs naturally and that can be replenished or renewed within a human lifespan, including, but not limited to moving water, wind, heat from the earth, sunlight, and sustainable biomass.

On November 3, 2016, the Government of Alberta announced the Renewable Electricity Program (REP) to enable Alberta to meet its legislated target of 30 per cent of its electricity being generated from renewable sources by 2030.

Three REP procurements were conducted for a total of approximately 1,360 megawatts of new renewable electricity capacity. According to Alberta Electric System Operator forecasts, it is expected the percentage of renewable electricity generated will significantly increase in 2019-20, as REP projects procured under the first three rounds of the program are scheduled to come on line.

The percentage change between 2017 and 2018 indicates a decrease in the renewable electricity share of total generation. In 2018, there was a decrease in both renewables (approximately 240 gigawatt hours decrease from 2017) and non-renewable generation (approximately 92.5 gigawatt hours decrease from 2017).

The decrease in renewable electricity generation from 9.91 per cent down to 9.64 per cent was a result of variability in wind resources (2018 slightly less windy than the year prior), and increased generation by natural gas in response to retired coal units.

Appendix A: Energy Highlights Table

Resource		2017-18	2018-19
Bitumen	Revenue	\$2.64 billion	\$3.21 billion
	Bitumen wells drilled ¹	1,309 (2017)	1,515 (2018)
	Total bitumen production in barrels per day (bbl/d)	2.83 million bbl/d (2017)	3.05 million bbl/d (2018)
	Marketable bitumen and Synthetic Crude Oil (SCO) production	2.68 million bbl/d (2017)	2.91 million bbl/d (2018)
Conventional Crude Oil	Revenue	\$0.96 billion	\$1.15 billion
	Average price for West Texas Intermediate (WTI)	US\$53.69/bbl	US\$62.73/bbl
	Conventional crude oil production	0.45 million bbl/d (2017)	0.49 million bbl/d (2018)
	Pentanes and condensate production	0.27 million bbl/d (2017)	0.32 million bbl/d (2018)
	Crude oil wells drilled ¹	1,831 (2017)	2,194 (2018)
Total Crude and Equivalent	Production (conventional, marketable bitumen and SCO, pentanes plus and condensates)	3.40 million bbl/d (2017)	3.72 million bbl/d (2018)
	Removals from Alberta	3.25 million bbl/d (2017)	3.53 million bbl/d (2018)
	Percentage of total crude oil and equivalent disposition	85% (2017)	86% (2018)
Natural Gas and By-Products	Revenue	\$0.64 billion	\$0.54 billion
	Average Alberta Natural Gas Reference Price (ARP)	\$1.82/GJ	\$1.34/GJ
	Number of conventional natural gas wells drilled ¹	1,295 (2017)	937 (2018)
	Total marketable natural gas production including Coalbed Methane	3.8 Tcf (2017)	3.8 Tcf (2018)
	Coalbed Methane production	0.22 Tcf (2017)	0.20 Tcf (2018)
	Total natural gas disposition	4.38 Tcf (2017)	4.53 Tcf (2018)
	* To the United States	37%	35%
	* Within Alberta	40%	43%
	* To rest of Canada	23%	22%
Bonuses and Sales of Crown Leases	Revenue from bonuses and sales of Crown leases	\$0.56 billion	\$0.36 billion
	Revenue from rentals and fees	\$0.15 billion	\$0.16 billion
	Average price per hectare (ha) paid at petroleum and natural gas rights sales ²	\$415.45	\$271.74
	Petroleum and natural gas hectares sold at auction ²	1,229,511 ha	1,301,265.72 ha

Resource		2017-18	2018-19
	Average price per hectare paid for oil sands mineral rights ²	\$234.09	\$161.76
	Oil sands hectares sold at auction ²	222,792 ha	35,862 ha
Freehold Mineral Tax	Revenue	\$67 million	\$67 million
Wells and Licences	Well Licences issued	5,800 (2017)	6,076 (2018)
	Industry drilling ³	5,308 (2017)	5,513 (2018)
Coal	Revenue	\$12 million	\$10 million
	Established coal reserves (estimate)	33.2 billion tonnes	33.2 billion tonnes
	Raw coal production	26.8 million tonnes (2017)	22.2 million tonnes (2018)
	Total marketable coal deliveries	24.2 million tonnes (2017)	18.9 million tonnes (2018)
	Percentage of total coal deliveries exported out of province	13.3 % (2017)	19.4 % (2018)
Electricity	Total generation capacity in Megawatts (MW)	16,702 (2017)	16,193 (2018)
	Total generation capacity from renewable sources	2,828 (2017)	2,825 (2018)
	Total generation capacity from coal	6,273 (2017)	5,273 (2018)
Metallic and Industrial Minerals	Metallic and Industrial minerals Royalty Revenues (MINRS)	\$540,773	\$714,947
	Hectares of mineral permits issued to exploration companies (LAMAS, MIM Permits and New Application Issued)	2.0 million ha	1.7 million ha
Upstream Energy Sector Direct and Indirect Employment⁴	Direct and indirect employment	423,000 (2017)	444,000 (2018)
Upstream Energy Sector Investment⁴	Investment	\$29.4 billion (2017)	Estimated \$28.2 billion (2018)

Notes:

1. Data on wells drilled include both development and exploratory wells.
2. 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.
3. 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.
4. This is the first annual report that reports upstream energy employment and investment statistics in the Energy Highlights Table.

Performance Measure and Indicator Methodology

Performance Measure 1.a: Revenues from oil, oil sands, gas and land sales bonuses are fully collected

Oil

Oil royalty volumes owed to the Crown are calculated in the Royalty and Marketing (RAM) system. The volumes owed to the Crown are taken in kind, rather than invoiced. The volumes owed are imported from RAM into the Crude Oil Operations system. Reconciliations between the volumes calculated by RAM and the volumes actually delivered by industry are performed by the department, who also follows up and resolves any discrepancies. The department collects the revenue for the Crown's volumes marketed either directly, or by the Crown's agents, then calculates the net value of all royalty sales, and remits the proceeds to Treasury Board and Finance.

Oil Sands

Oil Sands Administrative and Strategic Information System (OASIS) calculates the monthly amounts to be collected based on the Good Faith Estimates, the Monthly Royalty Calculations and the Non-Project Royalty reports and annual adjustments based on the End of Period Statements. All royalty reporting must be submitted electronically to the Department of Energy, using the web-based Electronic Transfer System (ETS). OASIS then sends the charge information to the Corporate Accounting and Reporting System (CARS2). During these processes, there are limited manual interfaces. An information report is available from OASIS to identify the reconciliation of OASIS to CARS2 charge transfers.

Land Sale Bonuses

The majority of oil sands and petroleum and natural gas agreements are acquired through a public tender process. Each year the department holds an average of 24 public sales, referred to as "Public Offerings". The word "sale" is used by tradition, although it is a misnomer, since the Crown always retains title to its minerals. The rights are leased, not sold. The process is an auction, in which companies or individuals submit bids on a parcel of oil sands or petroleum and natural gas rights. The highest bidder for each parcel is generally awarded an agreement. Individuals or companies submit a posting request electronically to the department through web-based ETS. The Public Offering, available on the department's website, is published eight weeks in advance of the sale date. Bidders can electronically submit bids for sale parcels through ETS until noon on the sale day. After this deadline, a user cannot submit or withdraw a bid. The total bid for each parcel must include a \$625 agreement issuance fee, the first year's annual rental of \$3.50 per hectare, and the bonus amount, as determined by the bidder. For oil sands rights, the standard minimum bonus bid is \$2.50 per hectare for leases and \$1.25 per hectare for permits. For petroleum and natural gas rights, the standard minimum bonus bid is \$2.50 per hectare for leases and \$1.25 per hectare for licences. The Electronic Funds Transfer (EFT) is the form of payment accepted for winning bids. The results of the sale are published on the department's website by 3:30 p.m. on the sale day. The sale results include the parcel number, the name of the successful bidder and the bonus amount paid for each parcel. After the sale, winning bids are uploaded from ETS to the Land Automated Mineral Agreement System (LAMAS). The following day, winning bids are uploaded from LAMAS to the Alberta Mineral Information (AMI) system. Payments are typically pulled electronically through LAMAS via EFT (Royal Bank on behalf of the department) on the day of the sale or the following day. Payments are then transferred to CARS2 as Revenues and Receivable. Payment is reflected in CARS2 as Cash in Transit and Receivables, which are then entered into the Integrated Management Alberta Government Information System (IMAGIS).

Gas

The Mineral Revenues Information System (MRIS) receives the data to perform monthly royalty calculations and generates a Gas Royalty Invoice on a monthly basis. MRIS passes a file to CARS2 and a Statement of Account is generated on or before the fifteenth of each month in MRIS and then issued to industry. Payments are due on the last day of the month. Aged Analysis reports are generated monthly on the CARS2 system. Collection action occurs on accounts that are past due.

Performance Measure 1.b: Alberta's oil sands supply share of global oil consumption

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:

$$\frac{\text{Annual barrels of Alberta oil sands production}}{\text{Barrels of world oil consumption}}$$

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 (AER) reports. Global oil consumption data is based on the Oil Market Report, published by the International Energy Agency.

Since the completion of the 2018-21 Control Record, there have been no changes in the methodology, with the exception of an addition of a new mined operator, Fort Hills, which commenced production in 2017, and significantly ramped up production in 2018. Therefore, 2017 and 2018 mined bitumen production results include production volumes from Fort Hills.

Performance Indicator 1.a: Price

Price, West Texas Intermediate (US\$/barrel)

This indicator was included in the 2018-21 Business Plan for the first time. The price that was chosen for the indicator is West Texas Intermediate (WTI). WTI is the North American price benchmark for light sweet oil. Prices are directly taken from U.S. Energy Information Administration's website, and re-arranged into fiscal year results.

Alberta Gas Reference Price (Cdn\$/gigajoule)

This indicator was included in the 2018-21 Business Plan for the first time. The price that was chosen for the indicator is Alberta Natural Gas Reference Price (ARP). ARP is one of the components used in natural gas royalty formulas to determine the Crown's revenue share of production. It is a monthly weighted average field price of all Alberta gas sales published by the Ministry of Energy. ARP data is taken directly from the Ministry of Energy's website, and rearranged into fiscal year results.

Performance Indicator 1.b: Production.

Alberta's crude oil and equivalent annual production

Volume (thousands of barrels/day)

- As a percentage of Canadian production

This indicator was included in the 2018-21 Business Plan for the first time. The indicator reports the volume of Alberta's annual crude oil and equivalent production, as well as Alberta's share of total Canadian production. It demonstrates the vital role that Alberta has in the Canadian oil market context. The indicator focuses 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 the indicator is taken from the National Energy Board (NEB). Generally, the Ministry of Energy relies on AER to report Alberta oil statistics. However, as the requirement of the indicator is to compare Alberta with the rest of Canada, NEB is used as a source to avoid mixing the sources.

Alberta's total marketable natural gas annual production

- Volume (billion cubic feet/day)
- As a percentage of Canadian production

Previously, this indicator included Alberta production volumes only, without putting Alberta in the Canadian context. Starting with the 2018-21 Business Plan, this 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 NEB. Generally, the ministry relies on AER to report Alberta gas statistics; in the 2017-20 Business Plan, AER was used as a source of Alberta gas production statistics. However, as the requirement of the present indicator is to compare Alberta with the rest of Canada, NEB is now used as a source to avoid mixing the sources.

Performance Indicator 1.c: Investment

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

- Cdn\$ (billions)
- Mining, Quarrying, and Oil and Gas Extraction Sector investment in Alberta as a Percentage of Canadian investment

This 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.

Previously, in the 2017-20 Business Plan, the indicator focused only on oil and gas extraction, which consists of both conventional oil and gas, and oil sands extraction. The revised indicator, which was included for the first time in 2018-21 Business Plan, has been expanded to include the entire upstream energy extraction sector; in addition to oil and gas extraction, the expanded indicator now also covers mining and quarrying, and support activities for mining, and oil and gas extraction. The updated indicator was reported by Ministry of Energy in the 2018-21 Business Plan.

The data for the Indicator is taken from Statistics Canada. Data is reported on a calendar year basis. In addition to actual results, the present indicator also reports the most current preliminary actual result, to enhance the timeliness of data presentation. The preliminary actual results will in all likelihood be revised once the actual results become available.

Downstream: Petroleum, Coal and Chemical Manufacturing

- Cdn\$ (billions)
- Alberta as a percentage of Canadian investment

In addition to upstream investment, the energy industry generates significant downstream activity; this 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 investment portion of the indicator was included in the 2018-21 Business Plan for the first time. This indicator can be treated as complementary to the "Upstream: Mining, Quarrying, and Oil

and Gas industry investment in Alberta” indicator, since that indicator covers upstream energy industry investment activity in Alberta. There is no overlap between the data reported by both indicators, as these indicators 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 this indicator is taken from Statistics Canada. Data is reported on a calendar year basis. In addition to actual results, the indicator also reports the most current preliminary actual result, to enhance the timeliness of data presentation. The preliminary actual results will in all likelihood be revised once the actual results become available.

Performance Indicator 1.d: Employment

Direct employment in the Mining, Quarrying and Oil and Gas Extraction sector (thousands)

This indicator was included in the 2018-21 Business Plan for the first time. The indicator reports the total number of people directly employed in Alberta as a result of the upstream mining, Quarrying and Oil and Gas Extraction sector activity. Data for this indicator is taken from Statistics Canada, and is reported on a calendar year basis.

Performance Indicator 1.e: Market Access

Total percentage of crude oil leaving Alberta

For 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 is calculated from the AER’s reports.

Total percentage of natural gas leaving Alberta

For 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: both components of the indicator were reported in the 2017-20 Business Plan; however, they were reported without the “Market Access” heading. In the 2018-21 Business Plan, performance indicator 1.e was identified as the “Market Access” indicator.

Performance Measure 2.a: Timeliness of the needs and facility applications

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.

Performance Indicator 2.a: Regulatory compliance

AER staff inspects operations of the upstream oil and gas and coal mining industries with respect to the drilling, production, and disposal of hydrocarbons and associated wastes. All inspection results are recorded into the Field Inspection System and result in an outcome of either compliant or noncompliant. If the inspection is noncompliant the triage tool is used to assess the significance of the noncompliance and determine the need for an investigation. If an investigation is warranted, information and evidence is collected relevant to the noncompliance. The investigation will determine if an enforcement action is required. Field inspections for this measure includes 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, and is counted based on the year the inspection was initiated. Inspections are counted based on the date of the initial inspection.

Performance Indicator 2.b: Pipeline incidents

The AER is focused on ensuring the safe transportation of hazardous products by regulating development in a way that reduces risk and ensures Albertans reap the economic rewards of the energy resources. A reportable pipeline incident under the AER'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 database by AER inspectors. The incident information is used to assign a consequence rating by the AER to indicate the potential severity of an incident. The rating is based on information of the incident regarding a set of indicators that reflect the impacts on the environment, wildlife, and public. 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. The Pipeline Technical Specialist and Industry Operations pipeline subject matter experts regularly complete data integrity reviews on pipeline incident records, which include the consequence rating assigned, and the inspection data. Records are reviewed for accuracy and consistency with established data integrity procedures.

Performance Measure 3.a: Transmission losses

Every year, the Alberta Electric System Operator (AESO) publishes two data points required for transmission line loss calculations: Alberta's annual internal load (in gigawatt hours) and line losses (in gigawatt hours). The calculation for this performance measure is:

$$\text{Transmission Losses (\%)} = \frac{\text{Annual total of monthly line loss volumes}}{\text{Annual total of monthly line loss factor customer volume}} \times 100\%$$

Source Documentation: AESO publishes Alberta's annual internal load each year in its Annual Market Statistics report at <https://www.aeso.ca/market/market-and-system-reporting/annual-market-statistic-reports/>. AESO publishes line losses each year in its annual report. AESO calculates line losses as follows:

$$\text{Line losses} = (\text{Total Generation} + \text{Imports}) - (\text{Total Consumption} + \text{Exports})$$

Performance Measure 3.b: Renewable generation

In Alberta, renewable generation refers to naturally occurring energy resources that can be replenished or renewed within a human lifespan, including, but not limited to moving water, wind, heat from the earth, sunlight, and sustainable biomass.

Electricity generation data from both renewable and non-renewable sources is collected and reported annually by the AUC. The source of information is regulatory filings under the *Hydro and Electric Energy Act* by operators of power generating facilities.

The result of the measure, for any given year, is calculated as follows:

$$\frac{\text{Electricity generated in Alberta from all renewable sources (megawatt hours)}}{\text{Total electricity generated in Alberta (megawatt hours)}} \times 100\%$$

The data is collected and reported annually by the AUC.

Financial Information

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Note: The financial statements for the Alberta Energy Regulator were not available prior to going to print and will be posted when available.

Ministry Financial Highlights

Statement of Revenues and Expenses

	2019		2018	Change from	
	Budget	Actual	Actual (Restated)	Budget	2018 Actual (Restated)
<i>(in thousands)</i>					
Revenues					
Non-Renewable Resource Revenue					
Bitumen Royalty	\$ 1,785,000	\$ 3,213,729	\$ 2,642,513	\$ 1,428,729	\$ 571,216
Crude Oil Royalty	1,053,000	1,149,125	964,956	96,125	184,169
Natural Gas and By-Products Royalty	541,000	535,925	644,502	(5,075)	(108,577)
Bonuses and Sales of Crown Leases	327,000	360,467	563,904	33,467	(203,437)
Rentals and Fees	112,000	159,961	152,642	47,961	7,319
Coal Royalty	11,000	9,803	11,632	(1,197)	(1,829)
Total Non-Renewable Resource Revenue	3,829,000	5,429,010	4,980,149	1,600,010	448,861
Freehold Mineral Rights Tax	87,000	66,882	67,360	(20,118)	(478)
Industry Levies and Licenses	336,337	339,449	299,582	3,112	39,867
Other Revenue	4,662	35,516	5,641	30,854	29,875
Net Income (Loss) from Government Business Enterprises					
Alberta Petroleum Marketing Commission	118,798	(215,109)	39,926	(333,907)	(255,035)
The Balancing Pool	160,931	360,880	762,541	199,949	(401,661)
Ministry total revenues	4,536,728	6,016,628	6,155,199	1,479,900	(138,571)
Inter-ministry consolidation adjustments	-	(146)	(1,123)	(146)	977
Ministry total revenues	4,536,728	6,016,482	6,154,076	1,479,754	(137,594)
Expenses - Directly Incurred					
Programs					
Ministry Support Services	3,977	4,204	4,757	227	(553)
Resource Development and Management	66,288	66,996	70,566	708	(3,570)
Cost of Selling Oil	79,600	79,512	74,623	(88)	4,889
Climate Leadership Plan	106,435	84,828	33,598	(21,607)	51,230
Carbon Capture and Storage	273,504	165,912	50,898	(107,592)	115,014
Market Access	-	5,850	-	5,850	5,850
Energy Regulation	253,250	259,451	253,253	6,201	6,198
Utilities Regulation	35,924	32,181	33,123	(3,743)	(942)
Orphan Well Abandonment	45,500	45,959	15,796	459	30,163
Ministry total expenses	864,478	744,893	536,614	(119,585)	208,279
Inter-ministry consolidation adjustments	-	(985)	(2,103)	(985)	1,118
Adjusted ministry total expenses	864,478	743,908	534,511	(120,570)	209,397
Annual Surplus	\$ 3,672,250	\$ 5,272,574	\$ 5,619,565	\$ 1,600,324	\$ (346,991)

Revenue and Expense Highlights

Revenues

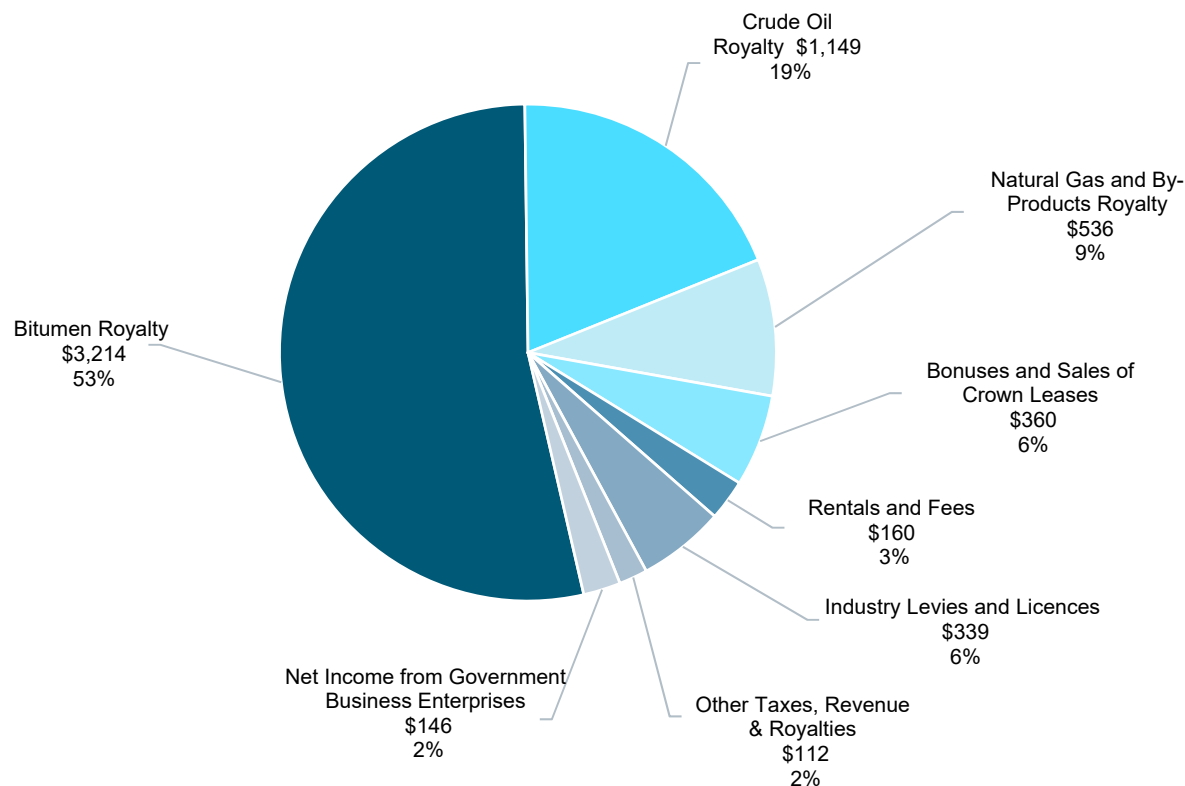
- Energy's 2018-19 total revenues of \$6,017 million consist of the following:
 - Non-Renewable Resource revenues totalling \$5,429 million was \$1,600 million higher than budgeted primarily due to increased Bitumen Royalties (\$1,429 million) and Crude Oil Royalties (\$96 million) as a result of higher than budgeted West Texas Intermediate (WTI) prices.
 - Freehold Mineral Rights Tax revenues totalled \$67 million and relate to annual taxes on private freehold mineral rights.
 - Industry levies and licences totalled \$339 million and relate to levies and licences collected from industry by the Alberta Energy Regulator (AER) and the Alberta Utilities Commission (AUC).
 - Net Income from Government Business Enterprises totalling \$146 million was lower than budget by \$134 million primarily due to lower than anticipated income from the Alberta Petroleum Marketing Commission (APMC) (\$334 million) due to a delay in the commercialization of the Sturgeon Refinery. This is offset by higher than anticipated income from the Balancing Pool (\$200 million) primarily as a result of increased revenues from electricity sales due to higher realized electricity prices.

Expenses

- Energy's 2018-19 fiscal year operating expenditures totalled \$745 million, with an operating surplus of \$120 million and increased spending of \$208 million compared to the 2017-18 fiscal year. This was primarily related to:
 - **Climate Leadership Plan** – The Regulated Rate Option (RRO) Rate Cap program was initiated to help provide financial relief to RRO customers in Alberta by providing a price cap on electricity prices, minimizing the impact of price volatility in the electricity market. There was increased spending of \$53 million in 2018-19 compared to 2017-18. However, this was \$22 million lower than originally budgeted as the third party forecast of electricity market prices was even higher.
 - **Carbon Capture and Storage** – This program supports Carbon Capture and Storage projects in Alberta. The Alberta Carbon Trunk Line Project (ACTL), which will transport captured CO₂ from the Industrial Heartland north of Edmonton to Central Alberta for enhanced oil recovery, reached a number of construction milestones during the year. These milestone achievements resulted in increased grant funding provided in 2018-19 compared to 2017-18 (\$115 million). The project did miss on reaching commercialization during the year, which resulted in a budget variance of \$108 million, which was anticipated as part of the budget.
 - **Market Access** – Development costs of \$6 million related to the setup of the Crude by Rail initiative, announced in November 2018, to address market access constraints that have landlocked Alberta resources from global export and lowered the relative value of Alberta resources from an international perspective. In February 2019, the APMC was directed, as an agent of the Crown, to proceed with the execution of the Crude by Rail program.

Breakdown of Revenues

2018-19 Actual Ministry Revenues (in millions)



Non-Renewable Resource and other Revenue

Non-Renewable Resource Revenue

Revenue (\$ Millions)	2018-19 Budget	2018-19 Actual
Bitumen	\$1,785	\$3,214
Conventional Oil	\$1,053	\$1,149
Natural Gas & By-Products	\$541	\$536
Land Sales	\$327	\$360
Rentals and Fees	\$112	\$160
Coal	\$11	\$10
Non-Renewable Resource Revenue	\$3,829	\$5,429

Bitumen royalties remained the largest portion of resource royalty revenue. In 2018-19, bitumen revenue totaled \$3.2 billion. Actual bitumen royalties were about 80 per cent, or \$1,429 million higher than budgeted. This variance is mainly due to higher than forecast WTI and Western Canadian Select (WCS) prices on average for the fiscal year.

Conventional crude oil royalties contributed \$1,149 million. Conventional crude oil royalties were \$96 million, or nine per cent higher than the budgeted amount due to higher than forecast prices for WTI and higher oil production.

Natural gas and by-products royalties brought in \$536 million and were \$5 million below the budgeted amount. Prices for natural gas by-products such as propane, butane and pentanes plus follow oil prices. The improved oil prices spurred increased production as companies are trying to maximize natural gas liquids extraction, especially pentanes plus used as diluent for oil sands production. This offset much of the lower than expected natural gas prices impact.

In 2018-19, **bonuses and sales of Crown leases** totaled \$360 million, which was \$33 million or 10 per cent higher than the budgeted amount. The majority of the sales (98 per cent) were from petroleum and natural gas leases (PNG). The number of PNG hectares sold was higher than forecast, more than offsetting a lower than expected average price per hectare.

Revenue from **rentals and fees** was \$160 million in 2018-19, exceeding the budgeted revenue by \$48 million, or 43 per cent. Rentals and fees revenue are tied to sales in the current and the previous four years. The higher than budgeted revenue was mainly due to higher number of hectares and retention rates for leases and licences by industry. This affects rental 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 \$112 million is revenue from coal royalty which brought in \$10 million and was \$1 million lower than budgeted amount. Also included is freehold mineral rights tax revenue which was \$67 million and was \$20 million lower than budget.

Industry levies and licences totalled \$339 million which primarily includes \$308 million from AER and \$31 million from AUC. Industry levies and licences were \$3 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.

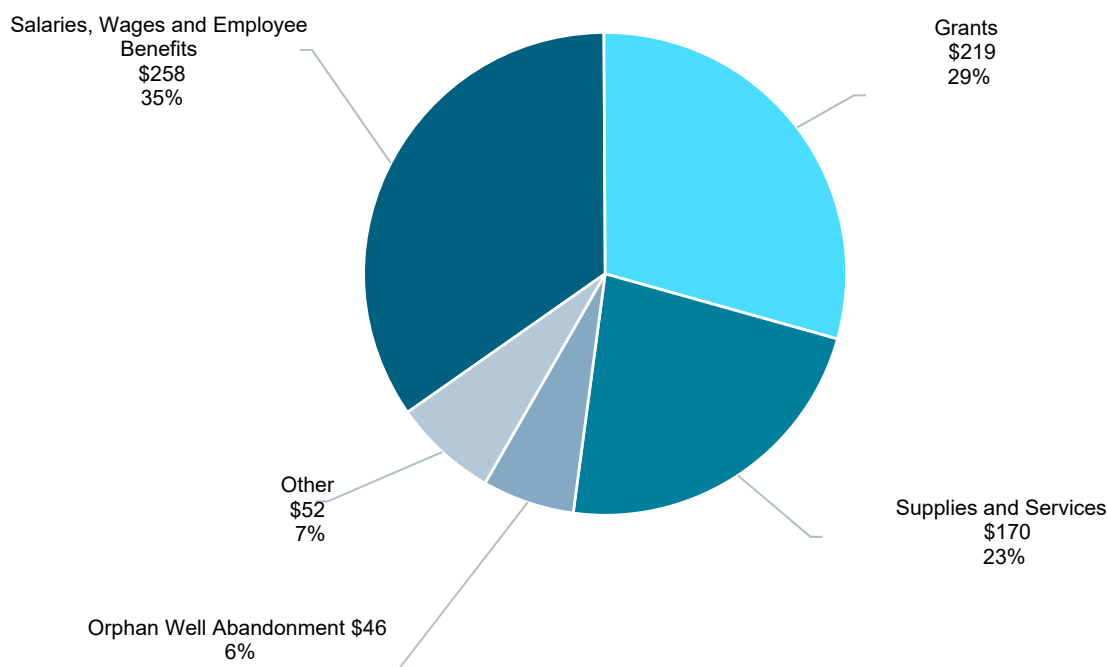
Net Income from Government Business Enterprises

- Net Income from Government Business Enterprises is comprised of the net income from the Balancing Pool of \$361 million offset by the net loss from the APMC of \$215 million.
 - The Balancing Pool's net income of \$361 million in 2018-19 reduced Net Liabilities from an opening balance of \$1.2 billion to \$829 million as of March 31, 2019. Higher than budgeted Net Income of \$200 million was a result of:
 - Increased revenues from sales of electricity due to higher realized electricity prices.
 - Higher revenues from consumer collection allocation due to increase in the collection levy in accordance with regulations.
 - Settlements with a municipal entity for payments in lieu of taxes (PILOT) revenue in favour of the Balancing Pool.
 - These increases are reduced by an increase in the provision for onerous contracts associated with the return of the Power Purchase Arrangements (PPAs) due to a relative decrease in the forward electricity market price to 2020.
 - The APMC's net loss of \$215 million reduced Net Assets from an opening balance of \$105 million to a Net Liabilities balance of \$110 million as of March 31, 2019. The net loss was driven primarily by:
 - 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 (TCD) which, per the agreement with the North West Redwater Partnership (NWRP), resulted in monthly debt tolls to be paid to NWRP to begin (totalling \$261 million).

Expenses – Directly Incurred Detailed by Object

2019 Actual

(in millions)



- **Salaries, Wages and Employee Benefits**, which represented 35 per cent of total operating expense, were the largest component of the ministry's operating expense (\$258 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 29 per cent of total operating expense, were the ministry's second largest operating expense (\$219 million) and primarily consisted of payments related to Carbon Capture & Storage projects (\$165 million) and the RRO rate cap program (\$53 million).
- **Supplies and Services** totalling \$170 million (23 per cent) primarily consist 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).
- **Orphan Well Abandonment** expenses, totalling \$46 million (six 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 \$52 million (seven per cent), primarily consist of accretion expenses related to the off coal agreements and amortization of tangible capital assets.

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, 2019, the Ministry of Energy has gas royalty deposits of \$136 million.

Coal Phase-Out Agreements

- The phase out of coal-fired generators is in alignment with the Province's Climate Leadership Plan (CLP). 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 (\$4 million in dispute) annually to the three generators. The first payment was made July 31, 2017 and payments will continue for the next 12 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 owner 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 12 payments, discounted at 3 per cent (representing the government's average 10-year bond rate at time of negotiations), is \$983 million. The amount of the draw down over the next five years and thereafter are as follows:

<i>(in thousands)</i>			
	Annual Payment	Principal	Interest
2019-20	96,970	69,098	27,872
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
Thereafter	678,793	615,499	63,294
	<u>\$1,163,643</u>	<u>\$ 982,610</u>	<u>\$ 181,033</u>

Crude by Rail

- Prepaid expenses of \$308 million are prepayments made for railway services to Canadian Pacific (CP) Railway and Canadian National (CN) Railway under the Province's Crude by Rail initiative announced in November 2018. The prepayments were a necessary part of the execution of the contracts and resulted in a reduction of future toll charges.

Equity in Government Business Enterprise

Alberta Petroleum Marketing Commission
 EQUITY IN GOVERNMENT BUSINESS ENTERPRISE
 For the year ended March 31, 2019
(in thousands)

	2019	2018
Accumulated surplus		
Opening accumulated surplus	\$ 104,999	\$ 65,073
Revenues		
Marketing of Oil	5,427	6,508
Financing Transactions	55,830	41,678
Total revenue	61,257	48,186
Total expense	276,366	8,260
Net income for the year	(215,109)	39,926
Accumulated surplus at end of year	\$ (110,110)	\$ 104,999
Represented by		
Assets		
Cash and short-term investments	\$ 7,418	\$ 7,458
Term Loan	605,297	543,111
Other assets	86,636	100,617
Total assets	699,351	651,186
Liabilities		
Accounts payable	26,630	11,272
Due to Government of Alberta	703,819	441,673
Due to the Department of Energy	79,012	93,242
Total liabilities	809,461	546,187
	\$ (110,110)	\$ 104,999

COMMITMENTS

(a) North West Redwater Partnership (NWRP)

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 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% of the project's feedstock) for 30 years. The toll includes flow through costs as well as costs related to facility construction, estimated to be \$9.9 billion (2018 - \$9.7 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 term of the commitment began June 1, 2018, at that time the APMC began paying its share of the debt tolls. The debt tolls paid from June, 2018 to March, 2019 totalling \$261 million have been expensed.

The nominal tolls under the processing agreement, assuming an \$9.9 billion (2018 - \$9.7 billion) Facility Capital Cost, market interest rates and 2% operating cost inflation rate, are estimated below. The total estimated tolls have been increased by \$0.69 billion (2018 - \$0.07 billion increase) relative to March 2018, due primarily to higher debt tolls related to higher Facility Capital Cost. As at March 31, 2019, NWRP has issued \$6.35 (2018 - \$6.35) billion in bonds.

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

(b) NWRP 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 2019. The future toll commitments are estimated to be:

2019-20	\$	447
2020-21		877
2021-22		1,014
2022-23		1,026
2023-24		1,006
Thereafter		22,345
	\$	<u>26,715</u>

(c) Term Loan Provided to NWRP

As part of the Subordinated Debt Agreement with NWRP, the APMC provided a \$439 million loan (2018 - \$432 million). These amounts plus the accrued interest will be repaid on a straight line basis over ten years by NWRP 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 NWRP are outstanding, the APMC is entitled to a 25 per cent 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, the APMC has significant influence over NWRP. However, the APMC has no equity ownership interest in NWRP and does not account for the Sturgeon Refinery or its operations and 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 APMC.

The APMC is forecasting to provide NWRP no additional subordinated debt in 2019 (2018 - \$13 million). In 2020 the APMC anticipates NWRP will repay \$90 million (2018 - \$94 million) to APMC as part of the final subordinated debt true-up six months after COD.

(d) NWRP 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 catalyst volumes or energy consumption; pricing related variables such as WTI prices, 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 forecasts of global consultancies, reserve evaluation consultants, forward markets and the Government of Alberta.

Based on the analysis, APMC determined the agreement has a positive net present value and no provision is required.

(e) Keystone XL Pipeline Project

Effective October 30, 2018 APMC has assigned these capacity agreements to another party. Therefore the APMC no longer has this commitment.

(f) Crude by Rail Project

On February 14, 2019 the Minister of Energy instructed the APMC, as agent of the Ministry of Energy, to execute a crude by rail program as part of the Government of Alberta's medium term solution to alleviate the constrained market access for Alberta's heavy crude oil production. The Department of Energy has evaluated this program

and the contracts thereunder in accordance with IFRS 15 Revenue from Contracts with Customers, and determined that the APMC is acting as agent for the Department of Energy on all commercial elements. As a result, all financial obligations, risks, and rewards of the program are borne by the Department of Energy.

(g) Subsequent Events

Short Term Debt

On April 4, 2019 APMC replaced its short term debt of \$116.1 million originally issued April 4, 2018 with new short term debt of \$118.3 million at 1.80% interest due April 2, 2020.

On April 25, 2019 APMC borrowed \$17.2 million of short term debt from Treasury Board and Finance at an effective interest rate of 1.80% due April 23, 2020.

On May 24, 2019 APMC borrowed \$16.304 million of short term debt from Treasury Board and Finance at an effective interest rate of 1.820% due May 22, 2020.

The Balancing Pool

The Balancing Pool
EQUITY IN GOVERNMENT BUSINESS ENTERPRISE
For the year ended March 31, 2019
(in thousands)

	2019	2018
Accumulated equity		
Opening accumulated equity	\$ (1,189,462)	\$ (1,952,003)
Total revenues	1,189,305	913,328
Total expense	1,012,126	249,003
Receipt of Consumer Allocation	183,701	98,216
Net income for the year	360,880	762,541
Accumulated equity at end of year	\$ (828,582)	\$ (1,189,462)
Represented by		
Assets		
Cash and cash equivalents	\$ 224,230	\$ 12,258
Term Loan	1,971	3,917
Other assets	762,214	314,558
Total assets	988,415	330,733
Liabilities		
Accounts payable ⁽¹⁾	229,692	375,432
Reclamation and abandonment provision	23,428	15,696
Loans and borrowing ⁽²⁾	826,937	802,703
Power Purchase Arrangement liabilities ⁽³⁾	736,940	326,364
Total liabilities	1,816,997	1,520,195
	\$ (828,582)	\$ (1,189,462)

- (1) Included in Accounts payable is \$28.0 million (2018 - \$61.7 million) of payments in lieu of taxes that are payable to a municipal entity.
- (2) Loans and borrowing is made up of short-term discount notes issued to the province with maturity dates ranging from 31 to 90 days with annual interest charges ranging from 2.16% to 2.65% (2018 - 1.64% to 1.69%).
- (3) The increase in Power Purchase Arrangement (PPA) liabilities is due to the adoption of IFRS 16 effective January 1, 2019 which resulted in the recognition of a lease liability of \$298 million (2018 - \$nil).

(a) 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 Balancing Pool was established as a separate statutory corporation on June 1, 2003.

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. When a buyer terminates a PPA, the Balancing Pool will assume all remaining rights and obligations pursuant to the PPA assuming the PPA continues. The *Electric Utilities Act* requires the Balancing Pool 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 Balancing Pool for financial reporting purposes with an effective date of January 1, 2017.

(b) Measurement Uncertainty

These financial statements are primarily based on the financial statements of the Balancing Pool for the year ended December 31, 2018 and unaudited interim financial statements for the period January 1 to March 31, 2019. The preparation of these financial statements requires the use of estimates and assumptions. These estimates and assumptions have been made using careful judgement. Actual results are likely to differ from the results derived using these estimates. As a consequence, there is a significant risk of a material adjustment to the carrying amounts of assets and liabilities within the next financial year.

(c) Contingent Liabilities and Commitments

Terminated Power Purchase Arrangements

The Sundance B and C Power Purchase Agreements were terminated effective April 1, 2018 and the Battle River 5 PPA was terminated effective October 1, 2018. Termination notices not been provided to the Owners of the remaining PPAs (Genesee, Sheerness and Keephills) as at March 31, 2019.

Retroactive Line Loss Adjustment

In December 2017, the Alberta Utilities Commission (AUC) reached its decision on Proceeding 790. As a result, 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 \$45.5 million (2017 – \$42.5 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, the Balancing Pool estimates may be higher or lower than the current estimate reflected in these financial statements.

Payments (Refunds) in Lieu of Tax

As a result of a settlement being reached approximately \$39.1 million was reversed from the previously accrued Payments (Refunds) in Lieu of Tax leaving a balance payable of \$28.0 (2018 - \$67.1 million to the municipal entity at March 31, 2019).

Lapse/Encumbrance

Department of Energy
LAPSE/ENCUMBRANCE
For the year ended March 31, 2019
(in thousands)

	Voted Estimate ⁽¹⁾	Supplementary Supply ⁽²⁾	Adjustments ⁽³⁾	Adjusted Voted Estimate	Voted Actuals ⁽⁴⁾	Unexpended (Over Expended)
Program - Operational						
Program - Ministry Support Services						
1.1 Minister's Office	\$ 830	\$ -	\$ -	\$ 830	\$ 1,013	\$ (183)
1.2 Deputy Minister's Office	485	-	-	485	497	(12)
1.3 Corporate Services	2,662	-	-	2,662	2,694	(32)
	3,977	-	-	3,977	4,204	(227)
Program - Resource Development and Management						
2.1 Revenue Collection	29,736	-	-	29,736	23,503	6,233
2.2 Resource Development	36,012	3,500	-	39,512	39,422	90
	65,748	3,500	-	69,248	62,925	6,323
Program - Cost of Selling Oil						
3 Cost of Selling Oil	79,600	10,400	-	90,000	79,512	10,488
	79,600	10,400	-	90,000	79,512	10,488
Program - Climate Leadership Plan						
4.1 Coal Phase-Out Agreements	29,907	-	-	29,907	29,907	-
4.2 Climate Leadership Initiatives	2,076	-	-	2,076	1,342	734
4.3 Regulated Rate Option Price Ceiling	74,310	(14,200)	-	60,110	53,466	6,644
4.4 Renewable Electricity Program	142	-	-	142	112	30
	106,435	(14,200)	-	92,235	84,827	7,408
Program - Crude by Rail						
5.1 Crude By Rail	-	7,000	-	7,000	5,850	1,150
	-	7,000	-	7,000	5,850	1,150
Total	\$ 255,760	\$ 6,700	\$ -	\$ 262,460	\$ 237,318	\$ 25,142
Lapse/(Encumbrance)						\$ 25,142
Program - Capital						
2.1 Revenue Collection	899	-	-	899	11	888
2.2 Resource Development	-	-	-	-	-	-
	899	-	-	899	11	888
Lapse/(Encumbrance)						\$ 888
Financial Transactions						
2.1 Revenue Collection	\$ -	\$ 1,262	\$ -	\$ 1,262	\$ 15	\$ 1,247
4.1 Coal Phase-Out Agreements	67,063	-	(62)	67,001	67,063	(62)
5.1 Crude By Rail	-	310,000	-	310,000	307,890	2,110
	\$ 67,063	\$ 311,262	\$ (62)	\$ 378,263	\$ 374,968	\$ 3,295
Lapse/(Encumbrance)						\$ 3,295

- (1) As per "Operational Vote by Program", "Voted Capital Vote by Program" and "Financial Transaction Vote by Program" page 116 of 2018-19 Government Estimates.
The Voted Estimate figures include adjustments related to program transfers to other ministries for Information Management & Technology per Order in Council OC2018-297 18.3(3) (\$3.1M), Human Resources per Order in Council OC2018-297 18.4(2) (\$1.7M), Freedom of Information and Protection of Privacy per Order in Council OC2018-297 18.3(2) (\$0.8M), and Economic Forecasting and Analysis per Order in Council OC2019-028 7(b)(5.2) (\$0.6M).
- (2) Per the Special Warrant (No. 001/2019) for Supplementary Supply approved on March 29, 2019 (Order in Council No. 084/2019). This disclosure is made pursuant to section 30 of the *Financial Administration Act*.
- (3) Adjustments include encumbrances, capital carry over amounts, transfers between votes and credit or recovery increases approved by Treasury Board and Finance and credit or recovery shortfalls. An encumbrance is incurred when, on a vote-by-vote basis, the total of actual disbursements in the prior year exceed the total adjusted estimate. All calculated encumbrances from the prior year are reflected as an adjustment to reduce the corresponding voted estimate in the current year.
- (4) Actuals exclude non-voted amounts such as statutory programs, amortization and valuation adjustments.

Financial Statements of Other Reporting Entities

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Note: The financial statements for the Alberta Energy Regulator were not available prior to going to print and will be posted when available.

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Alberta Utilities Commission

Financial Statements

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Independent Auditor's Report

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, 2019, 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, 2019, 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 13, 2019
Edmonton, Alberta

Statement of Operations

Year ended March 31, 2019
(in thousands)

	2019		2018
	Budget (Schedule 3)	Actual	Actual
	<i>----- (in thousands) -----</i>		
Revenues			
Administration fees	\$ 34,724	\$ 31,125	\$ 31,412
Investment income	300	310	227
Professional services and other revenue	100	389	175
	<u>35,124</u>	<u>31,824</u>	<u>31,814</u>
Expenses			
Utility regulation (Schedule 1)	<u>35,924</u>	<u>32,243</u>	<u>33,190</u>
Annual operating deficit	(800)	(419)	(1,376)
Accumulated surplus, beginning of year	<u>14,478</u>	<u>14,478</u>	<u>15,854</u>
Accumulated surplus, end of year	<u>\$ 13,678</u>	<u>\$ 14,059</u>	<u>\$ 14,478</u>

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

Statement of Financial Position

As at March 31, 2019
(in thousands)

	2019	2018
	----- <i>(in thousands)</i> -----	
Financial Assets		
Cash and cash equivalents (Note 5)	\$ 8,637	\$ 10,645
Accounts receivable	371	144
Accrued pension asset (Note 6)	345	290
	<u>9,353</u>	<u>11,079</u>
Liabilities		
Accounts payable and accrued liabilities (Note 7)	1,643	7,399
Deferred lease incentive (Note 8)	6,320	3,005
	<u>7,963</u>	<u>10,404</u>
Net Financial Assets	<u>1,390</u>	<u>675</u>
Non-Financial Assets		
Capital assets (Note 9)	11,423	12,462
Prepaid expenses	1,246	1,341
	<u>12,669</u>	<u>13,803</u>
Net Assets		
Accumulated surplus (Note 10)	<u>\$ 14,059</u>	<u>\$ 14,478</u>

Contractual obligations (Note 11)

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

Statement of Change in Financial Assets

Year Ended March 31, 2019

(in thousands)

	2019		2018
	Budget (Schedule 3)	Actual	Actual
	----- (in thousands) -----		
Annual operating deficit	\$ (800)	\$ (419)	\$ (1,376)
Acquisition of capital assets (Note 9)	(1,000)	(907)	(8,664)
Amortization of capital assets (Note 9)	1,800	1,933	1,472
Net (gain) loss on disposal of capital assets		(8)	476
Proceeds on disposal of capital assets		21	6
Increase (decrease) in prepaid expenses		95	(205)
Increase (decrease) in net financial assets in the year	-	715	(8,291)
Net financial assets, beginning of year	675	675	8,966
Net financial assets, end of year	\$ 675	\$ 1,390	\$ 675

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

Statement of Cash Flows

Year Ended March 31, 2019
(in thousands)

	<u>2019</u>	<u>2018</u>
	----- <i>(in thousands)</i> -----	
Operating transactions		
Annual operating deficit	\$ (419)	\$ (1,376)
Non-cash items included in annual deficit:		
Amortization of capital assets (Note 9)	1,933	1,472
Pension expense	540	697
Net (gain) loss on disposal of capital assets	(8)	476
(Increase) decrease in accounts receivable	(227)	111
Decrease (increase) in prepaid expenses	95	(205)
(Decrease) increase in accounts payable and accrued liabilities	(5,738)	4,435
Cash (applied to) provided by operating transactions	<u>(3,824)</u>	<u>5,610</u>
Capital transactions		
Acquisition of capital assets (Note 9)	(907)	(8,664)
Proceeds on disposal of capital assets	21	6
Cash applied to capital transactions	<u>(886)</u>	<u>(8,658)</u>
Financing transactions		
Pension obligations funded	(595)	(579)
Net lease incentives	3,315	2,706
Net lease obligations (repaid) capitalized	(18)	88
Cash provided by financing transactions	<u>2,702</u>	<u>2,215</u>
Decrease in cash and cash equivalents	(2,008)	(833)
Cash and cash equivalents, beginning of year	10,645	11,478
Cash and cash equivalents, end of year	<u><u>\$ 8,637</u></u>	<u><u>\$ 10,645</u></u>

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

Notes to the Financial Statements

March 31, 2019

(in thousands)

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.

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:

<u>Financial Statement Component</u>	<u>Measurement</u>
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.

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 represent 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.

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

Non-financial assets are limited to 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.

Change in accounting policy

The AUC has prospectively adopted PS 3430 Restructuring Transactions from April 1, 2018. The adoption of this standard did not affect the 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)

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.

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, 2019, 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, 2019, securities held by the Fund have a time-weighted return of 1.8 per cent per annum (2018: 1.1 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 \$1,810 for the year ended March 31, 2019 (2018: \$1,927). 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, 2016. The accrued benefit obligation as at March 31, 2019 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, 2019.

Pension plan assets are valued at market values. During the year ended March 31, 2019 the weighted average actual return on plan assets was 6.55 per cent (2018: 2.44 per cent).

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

	March 31, 2019	March 31, 2018
Accrued benefit obligations		
Discount rate	4.71%	4.70%
Rate of compensation increase	3.50%	3.50%
Long-term inflation rate	2.00%	2.00%

Note 6 Pension (continued)

	2019	2018
Pension Benefit costs for the year		
Discount rate	4.70%	4.40%
Expected rate of return on plan assets	4.70%	4.40%
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, 2019	March 31, 2018
Market value of plan assets	\$ 12,414	\$ 11,133
Accrued benefit obligations	11,276	10,275
Plan surplus	1,138	858
Unamortized actuarial (gain) loss	(793)	(568)
Accrued pension asset	<u>\$ 345</u>	<u>\$ 290</u>

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

	2019	2018
Current period benefit costs	\$ 556	\$ 614
Interest cost	484	504
Expected return on plan assets	(526)	(509)
Amortization of actuarial losses	26	88
	<u>\$ 540</u>	<u>\$ 697</u>

The average remaining service period of active employees is 6.6 years (2018: 6.6 years).

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

	2019	2018
AUC contribution	\$ 595	\$ 579
Employees' contribution	107	105
Benefits paid	168	1,107

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

	March 31, 2019	March 31, 2018
Equity securities	47.40%	45.80%
Debt securities	17.40%	18.10%
Other	35.20%	36.10%
	<u>100.00%</u>	<u>100.00%</u>

Note 7 Accounts payable and accrued liabilities

	2019	2018
Accounts payable	\$ 425	\$ 3,625
Accrued liabilities	1,148	3,686
Capital lease obligation	70	88
	<u>\$ 1,643</u>	<u>\$ 7,399</u>

Note 8 Deferred lease incentive

The AUC has received lease incentives through its office lease agreements. During 2019, the AUC received \$4,019 in lease incentives in the form of cash and free rent (2018: \$2,790).

	2019	2018
Opening balance	\$ 3,005	\$ 299
Cash incentive received	2,754	2,755
Rent free period received	1,265	35
Lease incentive amortized	(704)	(84)
Closing balance	<u>\$ 6,320</u>	<u>\$ 3,005</u>

Note 9 Capital assets

	March 31, 2019				March 31, 2018
	Furniture and equipment	Computer hardware and software	Leasehold improvement	Total	Total
Historical cost					
Beginning of year	\$ 2,855	\$ 8,625	\$ 9,409	\$ 20,889	\$ 15,223
Additions	286	608	13	907	8,664
Disposals	(32)	(30)	(3,097)	(3,159)	(2,998)
	<u>\$ 3,109</u>	<u>\$ 9,203</u>	<u>\$ 6,325</u>	<u>\$ 18,637</u>	<u>\$ 20,889</u>
Accumulated amortization					
Beginning of year	\$ 370	\$ 4,693	\$ 3,364	\$ 8,427	\$ 9,471
Amortization expense	314	946	673	1,933	1,472
Effect of disposals	(20)	(29)	(3,097)	(3,146)	(2,516)
	<u>\$ 664</u>	<u>\$ 5,610</u>	<u>\$ 940</u>	<u>\$ 7,214</u>	<u>\$ 8,427</u>
Net book value at March 31, 2019	<u>\$ 2,445</u>	<u>\$ 3,593</u>	<u>\$ 5,385</u>	<u>\$ 11,423</u>	<u>\$ 12,462</u>
Net book value at March 31, 2018	<u>\$ 2,485</u>	<u>\$ 3,932</u>	<u>\$ 6,045</u>	<u>\$ 12,462</u>	

Note 10 Accumulated surplus

Accumulated surplus is comprised of the following:

	2019			2018
	Investments in capital assets	Unrestricted surplus	Total	Total
Opening balance	\$ 12,462	\$ 2,016	\$ 14,478	\$ 15,854
Annual operating deficit	-	(419)	(419)	(1,376)
Net investment in capital assets	(1,039)	1,039	-	-
Closing balance	\$ 11,423	\$ 2,636	\$ 14,059	\$ 14,478

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
2020	\$ 3,563
2021	3,189
2022	2,568
2023	2,378
2024	2,480
Thereafter	9,557
	<u>\$ 23,735</u>

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, 2019 the AUC received and paid \$169 (2018: \$144) 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.

Schedule 1

Expenses – Detailed by Object

Year Ended March 31, 2019
(in thousands)

	2019		2018
	Budget	Actual	Actual
	----- (in thousands) -----		
Salaries, wages and employee benefits	\$ 26,142	\$ 24,390	\$ 22,847
Supplies and services	7,982	5,920	8,395
Amortization of capital assets (Note 9)	1,800	1,933	1,472
Loss on disposal of capital assets	-	-	476
	<u>\$ 35,924</u>	<u>\$ 32,243</u>	<u>\$ 33,190</u>

Schedule 2

Salary and Benefits Disclosure

Year Ended March 31, 2019
(in thousands)

	2019				2018
	Base Salary ⁽¹⁾	Other Cash Benefits ⁽²⁾	Other Non-cash Benefits ⁽³⁾	Total	Total
	<i>(in thousands)</i>				
Chair of the Commission ⁽⁴⁾	\$ 255	\$ 99	\$ 24	\$ 378	\$ 502
Vice-Chair	217	38	56	311	289
Commission Member	195	17	59	271	254
Commission Member	195	23	52	270	280
Commission Member	195	9	62	266	261
Commission Member	195	2	63	260	255
Commission Member	195	12	47	254	257
Commission Member ⁽⁵⁾	174	48	16	238	259
Commission Member ⁽⁶⁾	60	-	21	81	276

(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) Position was vacant from March 19, 2018 to May 7, 2018.

(6) Position became vacant as of July 23, 2018.

Schedule 3 Authorized Budget

Year Ended March 31, 2019
(in thousands)

	Budget (Estimate)	Authorized Changes	Authorized Budget	Actual
	<i>(in thousands)</i>			
Revenues				
Administration fees	\$ 34,724	\$ -	\$ 34,724	\$ 31,125
Investment income	300	-	300	310
Professional services	100	-	100	389
	<u>35,124</u>	<u>-</u>	<u>35,124</u>	<u>31,824</u>
Expenses				
Utility regulation	<u>35,924</u>	<u>-</u>	<u>35,924</u>	<u>32,243</u>
Net Capital Investment				
Capital investment	1,000	-	1,000	907
Less:				
Amortization	(1,800)	-	(1,800)	(1,933)
Net gain on disposal of capital assets	-	-	-	8
Proceed on disposal of capital assets	-	-	-	(21)
	<u>(800)</u>	<u>-</u>	<u>(800)</u>	<u>(1,039)</u>
	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ 620</u>

Note:

The Budget is based on the AUC Business Plan for the year ended March 31, 2019. The Budget has been approved by the government of Alberta.

Alberta Petroleum Marketing Commission

Financial Statements

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Independent Auditor's Report

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, 2018, and the statements of income (loss) and comprehensive income (loss), changes in net assets (liabilities) 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, 2018, 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

June 17, 2019
Edmonton, Alberta

Statement of Financial Position

As at December 31, 2018

(in thousands of Canadian dollars)

	2018	2017
Assets		
Cash and short term investments (Note 5)	\$ 5,725	\$ 7,173
Accounts receivable (Note 6)	7,243	91,284
Intangible assets under development (Notes 7 and 15)	9,818	8,125
Term loan (Note 9)	438,638	391,963
Accrued interest on term loan (Note 9)	152,044	98,746
Total assets	<u>\$ 613,468</u>	<u>\$ 597,291</u>
Liabilities		
Accounts payable (Note 10)	\$ 38,705	\$ 21,862
Due to the Department of Energy (Note 11)	2,707	81,118
Short term debt (Note 12)	625,228	391,963
Accrued interest on short term debt	16,303	8,017
Total liabilities	<u>\$ 682,943</u>	<u>\$ 502,960</u>
Net assets (liabilities)	<u>\$ (69,475)</u>	<u>\$ 94,331</u>
Total liabilities and net assets (liabilities)	<u>\$ 613,468</u>	<u>\$ 597,291</u>

Commitments (Note 14)

The accompanying notes are an integral part of these financial statements.

Statement of Income (Loss) and Comprehensive Income (Loss)

As at December 31, 2018

(in thousands of Canadian dollars)

	2018	2017
Conventional crude oil marketing operations		
Marketing fee revenue (Note 15)	\$ 5,717	\$ 6,304
Finance income	134	45
	<u>5,851</u>	<u>6,349</u>
Expenses		
Wages and benefits (Note 15)	3,529	3,816
Consulting	792	560
Dues and subscriptions	131	65
Software and maintenance (Note 15)	122	88
Directors' fees	49	66
Travel	30	11
Telephone	8	9
Conferences	4	8
Other	12	10
Change to loss provision for Accounts receivable	(49)	-
	<u>4,628</u>	<u>4,633</u>
Net income from conventional crude oil marketing operations	<u>1,223</u>	<u>1,716</u>
Sturgeon Refinery		
Finance income	53,359	37,850
Debt toll expense (Note 8)	(209,601)	-
Finance costs	(8,286)	(2,722)
Trust costs	(63)	(14)
Change to loss provision for Term loan & Accrued interest	157	-
Net income (loss) attributable to Sturgeon Refinery	<u>(164,434)</u>	<u>35,114</u>
Net income (loss) and comprehensive income (loss)	<u>\$ (163,211)</u>	<u>\$ 36,830</u>

The accompanying notes are an integral part of these financial statements.

Statement of Changes in Net Assets (Liabilities)

For the Year Ended December 31, 2018
(in thousands of Canadian dollars)

	2018	2017
Net assets, beginning of year	\$ 94,331	\$ 57,501
Credit loss provision per IFRS 9 (Note 3b)	(595)	-
Net income (loss) and comprehensive income (loss)	<u>(163,211)</u>	<u>36,830</u>
Net assets (liabilities), end of year	<u><u>\$ (69,475)</u></u>	<u><u>\$ 94,331</u></u>

The accompanying notes are an integral part of these financial statements.

Statement of Cash Flows

For the Year Ended December 31, 2018
(in thousands of Canadian dollars)

	2018	2017
Operating activities		
Net income (loss) and comprehensive income (loss)	\$ (163,211)	\$ 36,830
Credit loss provision per IFRS 9	(595)	-
Non-cash items included in net income		
Accrued interest on term loan	(53,298)	(37,850)
Accrued interest on short term debt	8,286	2,722
Changes in non-cash working capital		
Decrease/ (Increase) in accounts receivable	84,041	(13,202)
Increase in accounts payable	16,843	3,283
(Decrease)/ Increase in due to Department of Energy	(78,411)	13,309
Net cash from operating activities	<u>(186,345)</u>	<u>5,092</u>
Investing activities		
Term loan	(46,675)	(67,600)
Intangible assets under development	(1,693)	(2,095)
Net cash used in investing activities	<u>(48,368)</u>	<u>(69,695)</u>
Financing activities		
Proceeds from issuance of short term debt	233,265	67,600
Net cash from financing activities	<u>233,265</u>	<u>67,600</u>
(Decrease)/ Increase in cash and short term investments	(1,448)	2,997
Cash and short term investments, beginning of year	<u>7,173</u>	<u>4,176</u>
Cash and short term investments, end of year	<u><u>\$ 5,725</u></u>	<u><u>\$ 7,173</u></u>

The accompanying notes are an integral part of these financial statements.

Notes to the Financial Statements

As at December 31, 2018

(in thousands of Canadian dollars unless otherwise stated)

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 the APMC; modernized and improved the basic corporate rules under which the 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 the 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 June 17, 2019.

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 which 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.

Accounting policy changes

(a) IFRS 15 – Revenue from Contracts with Customers

On May 28, 2014, the IASB issued IFRS 15, “*Revenue from Contracts with Customers*” (“IFRS 15”) replacing International Accounting Standard 11, “*Construction Contracts*” (“IAS 11”), IAS 18, “*Revenue*” (“IAS 18”) and several revenue related interpretations. IFRS 15 establishes a single revenue recognition framework that applies to contracts with customers and prescribes additional disclosure requirements.

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 net assets (liabilities) 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 \$229 is being held in a fiduciary capacity on behalf of the Department at December 31, 2018 (\$1,588 as at December 31, 2017). 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) expected in late 2019.

(b) IFRS 9 - Financial Instruments

On July 24, 2014, the IASB issued the final version of IFRS 9, “*Financial Instruments*” (“IFRS 9”) to replace IAS 39, “*Financial Instruments: Recognition and Measurement*” (“IAS 39”). IFRS 9 introduces a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the IAS 39 requirements; however, where the fair value option is applied to financial liabilities, the change in fair value resulting from an entity’s own credit risk is recorded in Other Comprehensive Income rather than net earnings, unless this creates an accounting mismatch. In addition, a new expected credit loss model for calculating impairment on financial assets replaces the incurred loss impairment model used in IAS 39. The new model will result in more timely recognition of expected credit losses. IFRS 9 also includes a simplified hedge accounting model, aligning hedge accounting more closely with risk management. The Commission does not currently apply hedge accounting.

IFRS 9 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 can classify 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 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 term loan and accrued interest we measure expected credit losses using the default rates for the Government of Alberta and 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 is \$595 and reflected as a deduction to net assets (liabilities). The impairment provision calculated as at the reporting period December 31, 2018 is \$389 with the net adjustment from the January 1, 2018 amount going through the statement of income (loss) and comprehensive income (loss).

Existing accounting policies

(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 position 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.

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.

(g) Intangible assets under development

The Commission is in the process of replacing its legacy operating and accounting software. Costs related to software developed or purchased for internal use are capitalized if it is probable those future economic benefits will flow to APMC and that the cost can be measured reliably. Eligible costs include: billings from the Department's Information Management Technical Services (IMTS) group and Service Alberta for development; directly attributable costs; consulting and wages and benefits of people working on the project.

Once the project is complete the total cost will be amortized on a straight line basis over the estimated useful life of the software.

(h) Impairment of intangible assets under development

The carrying amounts of non-financial assets, which include the intangible assets under development, 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).

Prior accounting policies

(i) Revenue recognition

The Commission acted as an agent on behalf of the Department to accept delivery of and market the Province's royalty share of crude oil (the "conventional crude oil marketing activities"). As part of these activities, the Commission has entered into an agreement with Shell Trading Canada (Shell) for them to manage the transportation logistics and purchase approximately 90% of the royalty share of crude oil at index-based pricing. The Commission markets the remaining 10% of the royalty share. Amounts collected on behalf of the Department for conventional crude oil marketing activities are not revenue as the Commission never holds title to the barrels. Instead, the Commission earned revenue through marketing fees collected from the Department based on net volumes sold.

Revenue was recognized from marketing fees when earned, which corresponded to the service period in which the conventional crude oil marketing activities took place.

(j) Financial instruments

Financial assets and liabilities were recognized when the Commission became a party to the contractual provisions of the instrument. Financial assets were derecognized when the rights to receive cash flows from the assets expired or were transferred and the Commission had transferred substantially all of the risks and rewards of ownership. Financial liabilities were derecognized when the obligation specified in the contract was discharged, cancelled or expired or the cash flows were modified in a way that is in substance an extinguishment.

All financial instruments were initially recognized at fair value on the statement of financial position. Measurement of financial instruments subsequent to the initial recognition was based on how each financial instrument was initially classified. APMC's financial instruments were classified into the following two categories: financial assets at amortized cost; or financial liabilities at amortized cost. The Commission's financial assets included: cash and short term investments, accounts receivable and term loan. The Commission's financial liabilities consisted of: accounts payable, due to Department of Energy and short term debt. The financial assets and liabilities were measured subsequent to initial recognition at amortized costs using the effective interest method and impairment losses were recorded in the statement of income (loss) and comprehensive income (loss) when they occurred. Transaction costs adjusted the carrying amount initially recognized for a financial asset or liability.

Financial assets and liabilities were offset and the net amount reported in the statement of financial position when there was a legally enforceable right to offset the recognized amounts and there was an intention to settle on a net basis or realize the asset and settle the liability simultaneously.

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 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 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 additional revenues, expenses and amounts to be transferred to the Department of \$1,113,495 revenues, \$70,857 expenses and \$1,042,638 royalties to be transferred to the Department respectively (\$814,913 revenues, \$75,037 expenses and \$739,876 royalties to be delivered to the Department – 2017).

(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

In 2018 APMC lent an additional \$46.85 million (\$67.6 million 2017) to NWRP (total as at December 31, 2018 \$438.813 million) in the form of term loans. 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.

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 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.

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 updated facility capital cost (FCC) budget of \$9.925 billion (\$9.7 billion as at December 31, 2017). A higher than expected USD/CAD exchange rate, scope changes, and productivity challenges during construction 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 with COD in late 2019.

(d) NWRP - Monthly toll commitment

The Commission has used judgment to estimate the toll commitments included in Note 14 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.

(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 catalyst volumes or energy consumption; pricing related variables such as 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 forecasts of global consultancies, reserve evaluation consultants, forward markets and the Government of Alberta.

For the 2018 onerous contract analysis the concept of terminal value was introduced. Terminal value is an accepted method for calculating the value in use for assets beyond the forecast period. For the onerous contract review, the terminal value captures the remaining value of the contract after 40 years. This method replaces the previous practice of calculating net present value at 40, 50 and 60 years.

Based on the analysis as at the authorization date of these financial statements, APMC determined the agreement has a positive net present value and no provision is required.

Note 5 Cash and short term investments

	December 31, 2018	December 31, 2017
Cash and short term investments	\$ 5,230	\$ 5,248
Cash, Initial Proceeds Trust Account	495	1,925
	<u>\$ 5,725</u>	<u>\$ 7,173</u>

Cash and short term investments consist of deposits in the Consolidated Cash Investment Trust Fund (the "Fund") which is managed by the Province of Alberta 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. As at December 31, 2018, securities held by the Fund have a rate of return of 1.66% per annum (0.94% per annum – 2017). Due to the short term 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, 2018	December 31, 2017
Accounts receivable	\$ 7,396	\$ 91,284
Credit loss provision per IFRS 9	(153)	-
Balance, end of year	<u>\$ 7,243</u>	<u>\$ 91,284</u>

Note 7 Intangible assets under development

	December 31, 2018	December 31, 2017
Balance, beginning of year	\$ 8,125	\$ 6,030
Additions	1,693	2,095
Balance, end of year	<u>\$ 9,818</u>	<u>\$ 8,125</u>

Note 8 Pre Commercial Operations Date (COD) Debt Tolls

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 full debt toll invoiced to APMC for the June 1, 2018 to December 31, 2018 period has been expensed.

Note 9 Term loan and accrued interest on term loan

	December 31, 2018	December 31, 2017
TermLoan, beginning of year	\$ 391,963	\$ 324,363
Additions	46,850	67,600
TermLoan, end of year	438,813	391,963
Credit loss provision - TermLoan	(175)	-
Balance, end of year	<u>\$ 438,638</u>	<u>\$ 391,963</u>
	December 31, 2018	December 31, 2017
Accrued Interest on term loan, beginning of year	\$ 98,746	\$ 60,896
Additions	53,359	37,850
Accrued Interest on term loan, end of year	152,105	98,746
Credit loss provision - Accrued interest on term loan	(61)	-
Balance, end of year	<u>\$ 152,044</u>	<u>\$ 98,746</u>

During the year the Commission lent an additional \$46.850 million to NWRP 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, 2018. This information has been prepared in accordance with IFRS as issued by the IASB.

	NWRP (100% Interest)	
	2018	2017
Current assets	\$ 209,974	\$ 290,622
Non-current assets	\$ 11,246,141	\$ 10,540,474
Current liabilities	\$ 351,894	\$ 2,476,234
Non-current liabilities	\$ 10,535,327	\$ 7,769,344
Partners' equity	\$ 568,894	\$ 585,518
Revenue	\$ -	\$ -
Net income(loss) and comprehensive income (loss) attributable to Partners	\$ (16,624)	\$ 62,458

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.

The net loss and comprehensive loss in 2018 attributable to Partners primarily consists of general and administrative, and finance costs offset by some foreign exchange gains.

This note in 2017 incorrectly reported Non-current liabilities as \$10,245,578.

Note 10 Accounts payable

	December 31, 2018	December 31, 2017
Trade payables	\$ 35,598	\$ 12,122
GST	3,107	9,740
	<u>\$ 38,705</u>	<u>\$ 21,862</u>

Note 11 Due to the Department of Energy

	December 31, 2018	December 31, 2017
Due to Department, beginning of year	\$ 81,118	\$ 67,809
Amount to be transferred	1,042,638	739,876
Amount remitted	<u>(1,121,049)</u>	<u>(726,567)</u>
Due to Department, end of year	<u>\$ 2,707</u>	<u>\$ 81,118</u>

Note 12 Short term debt

	December 31, 2018	December 31, 2017
Balance, beginning of year	\$ 391,963	\$ 324,363
Additions	<u>233,265</u>	<u>67,600</u>
Balance, end of year	<u>\$ 625,228</u>	<u>\$ 391,963</u>

Details related to additions are as follows:

Date Issued	Amount	Interest Rate	Due Date
May 31, 2017	\$ 21,000	0.770%	May 30, 2018
Jun 30, 2017	1,500	1.041%	Jun 29, 2018
Jul 31, 2017	8,000	1.286%	Jul 30, 2018
Aug 31, 2017	6,750	1.350%	Aug 31, 2018
Sep 29, 2017	6,100	1.571%	Sep 28, 2018
Oct 31, 2017	7,850	1.520%	Oct 30, 2018
Nov 30, 2017	16,400	1.440%	Nov 29, 2018
	<u>\$ 67,600</u>		
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
	<u>\$ 233,265</u>		

APMC's intention is to borrow additional short term funds (with a one year term) from Treasury Board and Finance when these amounts come due and repay the aggregated amounts (both principal and interest) starting the year after the Sturgeon Refinery COD. The timing of APMC repaying of this debt is expected to correspond to NWRP's repayment of the term loan to the Commission (see Note 9). The increase in short term debt is mainly due to the requirement for APMC to pay debt toll invoices from NWRP starting June 1, 2018 (see Note 8).

Note 13 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, 2017.

(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 2017 and 2018, 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 2018 finance income by \$5.8 million (2017 \$4.8 million). A 100 basis point decline in prime would have reduced 2018 finance income by \$5.8 million (2017 \$4.7 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 2017) from Standard and Poor's. For 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, and the ability for the Commission to obtain financing through external banking credit facilities or obtaining borrowing 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)	\$ 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)
Accounts receivable (Note 6)	\$ 162,770	\$ 71,486	\$ 91,284
Accounts payable (Note 10)	(93,206)	(71,344)	(21,862)
Net position, December 31, 2017	\$ 69,564	\$ 142	\$ 69,422

(e) Capital management

The capital structure includes the Commission's net assets (liabilities). 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 selling 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.

Note 14 Commitments

	2019	2020	2021	2022	2023	Beyond 2024	Total
NWRP Tolls	\$ 297,000	\$ 834,000	\$ 1,007,000	\$ 1,034,000	\$ 1,002,000	\$ 22,600,000	\$ 26,774,000

(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) for 30 years. The toll includes flow through costs as well as costs related to facility construction, estimated to be \$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 Sturgeon Refinery did not attain COD in 2018, and per the PA, APMC was required to start paying at the Toll Commencement Date (June 1, 2018) only the debt toll, (see Note 8).

The nominal tolls under the processing agreement assuming: a \$9.925 billion FCC; market interest rates; and 2% operating cost inflation rate, are estimated above. The total estimated tolls have increased \$748 million relative to 2017, due primarily to increases in forecasted capital costs, interest and property taxes. As of the authorization date of these financial statements NWRP has issued \$6.35 billion in bonds at lower than anticipated rates.

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 \$90 million to APMC.

(c) Keystone XL Pipeline Project.

Effective October 30, 2018 APMC has assigned these capacity agreements to another party. Therefore the Commission no longer has this commitment.

Note 15 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 (2018 \$2,084, 2017 \$2,231) and software and maintenance (2018 \$39, 2017 \$72) within the statement of income (loss) and comprehensive income (loss). In addition some of the Department salaries have been capitalized within intangible assets under development (2018 \$154, 2017 \$173).

Starting in April, 2018 Service Alberta, a related party provided the software and maintenance services (2018 \$70) and are recognized within the statement of income (loss) and comprehensive income (loss). In addition their technology services related to software development (2018 \$905) have been capitalized within intangible assets under development.

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 to be related parties of the Commission. Transactions with close family members are immaterial; compensation for Board members and executive management is disclosed in Note 16.

Note 16 Salaries and benefit disclosure

Key management personnel include the Commission's Chief Executive Officer, Executive Director Business Development, Director of Finance and Board Members. The amounts in the financial statements relating to board members and key management compensation in 2018 and 2017 are as follows:

	2018				2017
	Base Salary	Other Cash Benefits (2)	Other Non-cash Benefits (3)	Total	Total
Board Members (1)	\$ -	\$ 49	\$ -	\$ 49	\$ 66
Chief Executive Officer - Prior	-	-	-	-	349
Chief Executive Officer - Interim	-	-	-	-	126
Chief Executive Officer - Current	301	66	6	373	12
Senior Management					
Executive Director, Business Development	348	39	6	393	452
Director of Finance	234	25	4	263	268

- (1) The Chair of the Board (Deputy Minister, Department of Energy) and one director (Assistant Deputy Minister, Department of Energy) are unpaid. Two outside Board Members were added in the 3rd quarter of 2017. One outside Board Member's term expired in the 1st quarter of 2019. Three new outside board members were added in the 1st quarter of 2019, bringing the total number of outside Board Members to five. The outside Board Members receive an annual retainer and meeting fees.
- (2) As per their employment contracts the three key management personnel receive cash payments in lieu of benefits.
- (3) Included in Other Non-cash benefits is parking.

The Prior Chief Executive Officer (CEO) resigned effective July 5, 2017. The Interim CEO was in place from July 6 to December 19, 2017. The Current CEO was hired effective December 20, 2017.

Note 17 Subsequent events

Short term debt.

On January 2, 2019 APMC replaced its short term debts of \$19.5 million and \$100.812 million originally issued January 2, 2018 with new short term debt of \$122.621 million at 2.103% interest due January 2, 2020.

On January 25, 2019 the Commission borrowed \$24.502 million of short term debt from Treasury Board and Finance at an effective interest rate of 2.040% due January 24, 2020.

On January 30, 2019 APMC replaced its short term debt of \$12.5 million originally issued January 31, 2018 with new short term debt of \$12.744 million at 2.015% interest due January 29, 2020.

On February 25, 2019 APMC borrowed \$16.877 million of short term debt from Treasury Board and Finance at an effective interest rate of 1.920% due February 24, 2020.

On February 27, 2019 APMC replaced its short term debt of \$4.7 million originally issued February 28, 2018 with new short term debt of \$4.808 million at 1.915% interest due February 26, 2020.

On March 25, 2019 APMC borrowed \$17.244 million of short term debt from Treasury Board and Finance at an effective interest rate of 1.780% due March 23, 2020.

On March 29, 2019 APMC replaced its short term debt of \$3.551 million originally issued March 29, 2018 with new short term debt of \$3.621 million at 1.770% interest due March 27, 2020.

On April 4, 2019 APMC replaced its short term debt of \$116.127 million originally issued April 4, 2018 with new short term debt of \$118.282 million at 1.796% interest due April 2, 2020.

On April 25, 2019 APMC borrowed \$17.201 million of short term debt from Treasury Board and Finance at an effective interest rate of 1.799% due April 23, 2020.

On May 24, 2019 APMC borrowed \$16.304 million of short term debt from Treasury Board and Finance at an effective interest rate of 1.820% due May 22, 2020.

On May 30, 2019 APMC replaced its short term debt of \$21.203 million originally issued May 30, 2018 with new short term debt of \$21.623 million at 1.795% interest due May 28, 2020.

Crude-by-rail Program

On February 14, 2019 the Minister of Energy instructed APMC, as agent of the Crown, to execute a crude-by-rail program as part of the Government of Alberta's plan to alleviate the constrained market access for Alberta's heavy crude oil production. Consequently during February and March of 2019 various commercial agreements were entered into between APMC and crude-by-rail market participants.

The Commission has evaluated the program and the contracts thereunder with respect to IFRS 15, *Revenue from Contracts with Customers*, and determined that APMC is acting as agent for the Department on all commercial elements. As a result, all financial obligations, risks and rewards of the program are borne by the Department.

Post-closure Stewardship Fund

Financial Statements

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Independent Auditor's Report



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, 2019, 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, 2019, 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 other information comprises the information included in the *Energy Annual Report 2018-2019*, but does not include the financial statements and my auditor's report thereon. The *Energy Annual Report 2018-2019* 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

June 7, 2019
Edmonton, Alberta

Statement of Operations

Year Ended March 31, 2019
(in thousands)

	2019		2018
	Budget	Actual	Actual
Revenue			
Injection Levy (Note 3)	\$ 230	\$ 251	\$ 248
Investment Income	-	10	4
Net Operating Results	<u>230</u>	<u>261</u>	<u>252</u>

The accompanying notes are part of these financial statements.

Statement of Financial Position

As at March 31, 2019
(in thousands)

	<u>2019</u>	<u>2018</u>
Assets		
Cash (Note 4)	\$ 779	\$ 536
Accounts Receivable	146	128
Net Assets	<u>\$ 925</u>	<u>\$ 664</u>
 Net Assets at Beginning of Year	 \$ 664	 \$ 412
Annual Operating Results	261	252
Net Assets at End of Year	<u>\$ 925</u>	<u>\$ 664</u>

The accompanying notes are part of these financial statements.

Statement of Change in Net Financial Assets

Year Ended March 31, 2019
(in thousands)

	2019		2018
	Budget	Actual	Actual
Annual Operating Results	\$ 230	\$ 261	\$ 252
Increase in Net Assets	\$ 230	\$ 261	\$ 252
Net Assets at Beginning of Year	-	664	412
Net Assets at End of Year	\$ 230	\$ 925	\$ 664

The accompanying notes are part of these financial statements.

Statement of Cash Flows

Year Ended March 31, 2019

(in thousands)

	<u>2019</u>	<u>2018</u>
Operating Transactions		
Net Operating Results	\$ 261	\$ 252
Decrease in Accounts Receivable	<u>(18)</u>	<u>12</u>
Increase in Cash and Cash Equivalents	\$ 243	\$ 264
Cash and Cash Equivalents at Beginning of Year	<u>536</u>	<u>272</u>
Cash and Cash Equivalents at End of Year	<u>\$ 779</u>	<u>\$ 536</u>

The accompanying notes are part of these financial statements.

Notes to the Financial Statements

March 31, 2019
(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.

Valuation of 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, 2019, 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 16% 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 General Revenue Fund on behalf of the Post Closure Stewardship Fund. The fund earns interest at Prime less 2.25%. The funds have been internally restricted under Section 122 of the MMA and is not available for government's general use. Any income earned on the Fund is likewise restricted in its use.

NOTE 5 APPROVAL OF FINANCIAL STATEMENTS

The Deputy Minister and the Senior Financial Officer approve these financial statements.

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Balancing Pool

Financial Statements

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balancingpool

2018 **Annual Report**

Excerpt: Pages 25-56



Financial Statements

Years Ended December 31, 2018 and 2017

Independent Auditor's Report



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, 2018 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, 2018;
- 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
PwC Tower, 18 York Street, Suite 2600, Toronto, Ontario, Canada M5J 0B2
T: +1 416 863 1133, F: +1 416 365 8215

"PwC" refers to PricewaterhouseCoopers LLP, an Ontario limited liability partnership.



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.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta
April 12, 2019

Statements of Financial Position

<i>(in thousands of Canadian dollars)</i>	2018	2017
Assets		
Current assets		
Cash and cash equivalents	175,851	50,772
Trade and other receivables (Note 5)	201,250	130,124
Current portion of long-term receivables (Note 6)	1,980	1,980
Current portion of hydro power purchase arrangement (Note 8 b i)	89,343	57,566
Intangible assets (Note 7)	26,899	153,120
	495,323	393,562
Long-term receivables (Note 6)	1,961	3,902
Investments (Note 9)	-	12,370
Property, plant and equipment	4	27
Hydro power purchase arrangement (Note 8 b i)	45,997	120,250
Total Assets	543,285	530,111
Liabilities		
Current liabilities		
Trade payable and other accrued liabilities (Note 11)	305,357	561,713
Current portion of related party loan (Note 17)	412,402	566,315
Current portion of small power producer contracts (Note 8 b ii)	444	3,424
Current portion of reclamation and abandonment provision (Note 12)	1,680	7,767
Current portion of other long-term obligations (Note 13)	79,723	529,073
	799,606	1,668,292
Small power producer contracts (Note 8 b ii)	-	298
Reclamation and abandonment provision (Note 12)	22,482	13,871
Other long-term obligations (Note 13)	164,760	128,648
Related party loan (Note 17)	502,893	-
Total Liabilities	1,489,741	1,811,109
Net liabilities attributable to the Balancing Pool deferral account (Note 1, 14)	(946,456)	(1,280,998)
Contingencies and commitments (Note 15)		
Subsequent events (Note 18)		

On behalf of the Balancing Pool:



Robert Bhatia
Chair



Greg Pollard
Audit and Finance Committee Chair

The accompanying notes are an integral part of these financial statements.

Statements of Income and Comprehensive Income

<i>(in thousands of Canadian dollars)</i>	2018	2017
Revenue from contracts with customers		
Sale of electricity and ancillary service (Note 3)	969,596	661,586
Consumer collection (Note 3)	189,259	66,003
Sale of generating capacity and termination revenue (Note 3)	-	716
	1,158,855	728,305
Other income from operating activities		
Changes in fair value of hydro power purchase arrangement (Note 8 b i)	44,258	159,718
Payments in lieu of tax (Note 15)	130,784	3,069
Investment income – interest and dividends	1,362	313
Changes in fair value of small power producer contracts (Note 8 b ii)	1,007	3,404
Changes in fair value of investments	4	32
	177,415	166,536
Expenses		
Cost of sales (Note 16)	843,212	621,571
Mandated costs (Note 17)	4,476	6,227
General and administrative	4,204	4,139
Force majeure costs	384	5,306
Investment management costs	13	31
Reclamation and abandonment provision (Note 12)	10,526	(7,109)
Power purchase arrangement provision (Note 13)	122,604	(424,544)
	985,419	205,621
Income from operating activities	350,851	689,220
Other income (expense)		
Finance expense (Note 10)	(16,417)	(3,558)
Other income	108	128
	(16,309)	(3,430)
Change to the Balancing Pool deferral account (Note 14)	334,542	685,790

The accompanying notes are an integral part of these financial statements.

Statements of Cash Flows

<i>(in thousands of Canadian dollars)</i>	2018	2017
Cash flow provided by (used in)		
Operating activities		
Change to the Balancing Pool deferral account	334,542	685,790
Items not affecting cash		
Amortization, depreciation and impairment	23	30
Reclamation and abandonment provision (Note 12)	10,526	(7,109)
Power purchase arrangement provision (Note 13)	(413,238)	(1,086,052)
Line loss provision (Note 15)	(3,066)	(114,042)
Fair value changes on small power producer contracts (Note 8 b ii)	(1,007)	(3,404)
Fair value changes on hydro power purchase arrangement (Note 8 b i)	(44,258)	(159,718)
Fair value changes on investments	1	(1)
Finance expense (Note 10)	16,417	3,558
Emission credits retired (received) (Note 7)	159,754	(2,000)
Reclamation and abandonment expenditures (Note 12)	(8,333)	(1,480)
Net change in other assets:		
Long-term receivable (Note 6)	1,941	1,942
Net change in non-cash working capital:		
Trade and other receivables	(71,126)	(52,967)
Trade payable and other accrued liabilities	(253,289)	189,591
Net cash used in operating activities	(271,113)	(545,862)
Investing activities		
Interest, dividends and other gains	(89)	(186)
Sale of investments (Note 9)	12,458	3,501
Purchase of intangible assets (Note 7)	(33,533)	(1,831)
Net cash (used in) provided by investing activities	(21,164)	1,484
Financing activities		
Hydro power purchase arrangement net receipts (Note 8 b i)	86,734	20,333
Proceeds from issue of related party loan	332,893	562,952
Small power producer contracts net payments (Note 8 b ii)	(2,271)	(4,213)
Net cash provided by financing activities	417,356	579,072
Change in cash and cash equivalents	125,079	34,694
Cash and cash equivalents, beginning of year	50,772	16,078
Cash and cash equivalents, end of year	175,851	50,772

The accompanying notes are an integral part of these financial statements.

Notes to Financial Statements

1. Reporting Entity and Nature of Operations

Formation and Duties of the Balancing Pool

The Balancing Pool was created by the Government of Alberta to help manage certain assets, liabilities, revenues and expenses arising from the transition to competition in 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). The requirement to establish the Balancing Pool was set out in the *Balancing Pool Regulation*.

With the proclamation of the *Electric Utilities Act (2003)* (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 Balancing Pool.

Under the EUA the Corporation is required to operate with no profit or loss (Note 14) and no share capital for the Corporation has been issued. The Balancing Pool 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 the 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 which 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 17).

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, Battle River 5, Sheerness, Keephills, Sundance A, Sundance B and Sundance C.

The Balancing Pool has also earned revenue from the sale of generating capacity in the form of strip contracts which transfer the associated offer rights and energy output of the Genesee PPA to third party buyers.

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

Effective January 1, 2017, the Corporation adopted International Financial Reporting Standards ("IFRS") 15, *Revenue from contracts from customers*. 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 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 Administration.

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, 2018 have been prepared by management in accordance with IFRS as issued by the International Accounting Standards Board ("IASB") and include as comparative information the year ended December 31, 2017.

These financial statements were authorized and approved for issue by the Board of the Balancing Pool on April 12, 2019.

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 and investments, which are measured at fair value.

Revenue from Contracts with Customers

The Balancing Pool adopted IFRS 15, *Revenue from contracts with customers*, effective for its annual reporting period commencing January 1, 2017. No revenue contracts that required cumulative adjustments on transition were identified as at January 1, 2017.

(a) Sale of electricity, ancillary service and generating capacity

Revenues from the sale of electricity, ancillary services and generating capacity 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, generating capacity 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, generating capacity and ancillary services.

(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 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.

Cash and Cash Equivalents

Cash and cash equivalents are comprised of cash on deposit at the bank.

Trade and Other Receivables and Prepaid Expenses

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 acquired through PPA negotiated settlements and 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 as long-term receivables with fixed payments receivable on each of December 31, 2019 and 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 forecasting future prices using a merit order dispatch model.

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.

Investments

The Corporation has designated its fixed income securities upon initial recognition at fair value through profit and loss in accordance with IFRS 9, *Financial Instruments*. They are recorded at estimated fair value, as of the period end date, measured based on the bid price in active markets. Unrealized gains or losses resulting from changes in fair value are recorded in income.

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, 2018 related to trade and other receivables. The Corporation considers trade and other receivables to be low risk.

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 7 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. This provision does not apply to generation units that are decommissioned 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.

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 has recognized onerous contract provisions 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.

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.

Power Purchase Arrangement and Related Finance Lease Obligation

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.

The finance lease obligations for the PPAs are fully impaired and are now recognized and reported as part of other long-term obligations (provision for onerous contracts).

New standards adopted during the period

Financial Instruments

On adoption of IFRS 9, in accordance with its transitional provisions, the Balancing Pool has not restated prior periods but has classified the financial assets held at January 1, 2018, retrospectively based on the new classification requirements and the characteristics of each financial instrument at the transition date. Adoption of IFRS 9 did not result in statement of financial position reclassifications or any impact to earnings.

The Balancing Pool's financial assets and liabilities are classified and measured at amortized cost ("AC"), except for Investments, Hydro PPA, Small Power Producer contracts, which are measured at fair value through profit or loss ("FVTPL"). The financial instrument classifications according to International Accounting Standard ("IAS") 39 did not change on adoption of IFRS 9.

For financial assets, the adoption of IFRS 9 did not have a material impact on the Balancing Pool's accounting policies for financial assets or derivative financial instruments.

For financial liabilities, IFRS 9 retains most of the IAS 39 requirements. Because the Balancing Pool has not elected the option of designating any financial liabilities at fair value through profit or loss and does not have embedded derivatives, the adoption of IFRS 9 did not impact the Balancing Pool's accounting policies for financial liabilities or derivative financial instruments.

The impairment requirements of IFRS 9 did not have any material impact on the Balancing Pool's financial statements.

Accounting Standards Issued But Not Yet Adopted

The IASB issued the following standard, which is issued but has not yet been adopted by the Balancing Pool.

IFRS 16 – Leases – In January 2016, the IASB issued IFRS 16 *Leases*, which replaces the current IFRS guidance on leases. IFRS 16 provides a single lessee accounting model, requiring lessees to recognize assets and liabilities for all leases unless the lease term is 12 months or less or the underlying asset has a low value. The approach to lessor accounting will remain unchanged from its predecessor, IAS 17. IFRS 16 is effective for annual periods beginning on or after January 1, 2019.

The Balancing Pool is currently evaluating the impact that the amended standard will have on its financial statements. The Balancing Pool will recognize right-of-use lease assets and related lease liabilities for the office lease and the PPAs.

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, 14);
- forecasting future power prices and capacity factors; and
- estimating the amount of the liability related to AUC Proceeding 790 ("retroactive line loss adjustment") (Note 15).

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 are 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 13)
- Accrued liabilities, Retroactive line loss adjustment (Note 15)

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.

5. Trade and Other Receivables

<i>(in thousands of dollars)</i>	December 31, 2018	December 31, 2017
Trade receivables	198,634	125,366
Other receivables	2,616	4,758
	201,250	130,124

6. Long-term receivables

<i>(in thousands of dollars)</i>	December 31, 2018	December 31, 2017
Opening balance, long-term receivable	5,882	7,824
Accretion	59	58
Emission credits received from PPA settlement	-	(2,000)
Cash received from PPA settlement	(2,000)	-
Closing balance, long-term receivable	3,941	5,882
Less: Current portion	(1,980)	(1,980)
	1,961	3,902

The \$2.0 million in cash was received from the PPA settlement in December 2018.

7. Intangible Assets

(in thousands of dollars)	December 31, 2018	December 31, 2017
Opening balance, emission credits	153,120	149,289
Additions from purchases	33,533	1,831
Additions from PPA settlement received	5,000	2,000
Retirement of emission credits	(164,754)	-
Closing balance, emission credits	26,899	153,120

At December 31, 2018, the Balancing Pool had \$26.9 million (2017 – \$153.1 million) in emission credits, which can be used to offset compliance obligations associated with the PPAs. In 2018, the Balancing Pool received \$5.0 million (2017 – \$2.0 million) in emissions credits as part of the negotiated settlements reached for certain terminated PPAs and purchased \$33.5 million (2017 – \$1.8 million) in emission credits.

No impairments of emission credits were recognized during the year ended December 31, 2018 (2017 – \$nil).

8. Accounting for Financial Instruments

8. a) Risk Management Overview

The Balancing Pool's activities expose the Balancing Pool to a variety of financial risks: market risk (including fluctuating market prices, plant availability, risks associated with PPA payments and 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 PPAs, including the hydro PPA. 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. A 1% increase to the long-term government bond rate would increase the annual capacity payments by an estimated \$11.1 million for the PPAs. Likewise a 1% decrease to the long-term government bond rate would decrease the annual capacity payments by an estimated \$11.2 million.

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) **Price Risk:** The investment portfolio is exposed to fixed income securities price risk. This arises from investments held in the investment portfolio for which prices in the future are uncertain.
- iii) **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 and a credit-worthy financial institution, respectively. The Balancing Pool does not consider any of the trade or long-term accounts receivable to be impaired or past due.
- iv) **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 17).

The following below 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
<i>(in thousands of dollars)</i>	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
<i>(in thousands of dollars)</i>	December 31, 2017		
Trade payables	199,647	-	199,647
Other accrued liabilities	362,066	-	362,066
Small power producer contracts	3,424	298	3,722
Related party loan	566,315	-	566,315
Reclamation and abandonment	7,767	13,871	21,638
Other long-term obligations	529,073	128,648	657,721
Total	1,668,292	142,817	1,811,109

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 1,620 gigawatt hours (“GWh”) per annum for 2019 and 2020. Hydro PPA receipts are settled on a monthly basis.

The remaining term of the hydro PPA is two years to December 31, 2020. At December 31, 2018, the net present value of the hydro PPA was estimated at \$135.3 million (2017 – \$177.8 million). Key assumptions in this valuation are a discount rate of 11.5% (2017 – 11.1%) and an estimated forecast average market electricity price of \$55.28/megawatt hour (“MWh”) for 2019 and \$49.19/MWh for 2020 (2017 – \$51.95/MWh for 2018 to 2020).

Hydro Power Purchase Arrangement (in thousands of dollars)	2018	2017
Hydro power purchase arrangement, opening balance	177,816	38,431
Accretion and current year change	48,959	34,306
Net cash receipts	(86,734)	(20,333)
Revaluation of hydro power purchase arrangement asset	(4,701)	125,412
Hydro power purchase arrangement, closing balance	135,340	177,816
Less: Current portion receivable	(89,343)	(57,566)
	45,997	120,250

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.

(in thousands of dollars)	Impact of change to price volatility		Impact of change to discount rate	
	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, 2018	25,685	(25,577)	(1,690)	1,729
Change in fair value as at December 31, 2017	34,663	(34,663)	(3,214)	3,312

ii) Small power producer contract

At December 31, 2018, one small power producer contract with a total allocated capacity of 10 megawatts ("MW") remains active (2017 – one contract with capacity of 10 MW). The contract price is \$79.70/MWh and expired on February 15, 2019. Under this contract, the price that the small power producer receives from the counterparty utility company is 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.

At December 31, 2018, the net present value of cash flows from the Balancing Pool for this contract was estimated to be a \$0.4 million liability (2017 – \$3.7 million liability). The estimated value of this liability varies based on the assumptions used and there is a high degree of measurement uncertainty. The key assumption used in this valuation is an estimated forecast average electricity market price of \$52.09/MWh for January to February 2019 (2017 – \$50.58/MWh for 2018 to 2019).

Small Power Producer Contract (in thousands of dollars)	2018	2017
Small power producer contract, opening balance	(3,722)	(11,339)
Accretion and current year change	1,090	1,616
Net cash payments	2,271	4,213
Revaluation of small power producer contract	(83)	1,788
Small power producer contracts, closing balance	(444)	(3,722)
Less: Current portion	444	3,424
	-	(298)

A 10% change to the forecast electricity market price or discount rate does not have a material effect on the value of the small power producer contract.

8. c) Fair Value Hierarchy

Financial instruments carried at fair value are categorized as follows:

	Quoted prices in active markets for identical assets	Significant other observable inputs	Significant unobservable inputs	Total
	Level 1	Level 2	Level 3	
(in thousands of dollars)				
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
December 31, 2017				
Assets				
Cash and cash equivalents	50,772	-	-	50,772
Investments	-	12,370	-	12,370
Hydro power purchase arrangement	-	-	177,816	177,816
	50,772	12,370	177,816	240,958
Liabilities				
Small power producer contracts	-	-	3,722	3,722
	-	-	3,722	3,722
	50,772	12,370	174,094	237,236

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, 2018 and 2017 are disclosed in note 8 b i) and in note 8 b ii).

9. Investments

<i>(in thousands of dollars)</i>	2018	2017
Investments, beginning of year	12,370	15,684
Interest and dividends	83	155
Realized capital gains	5	31
Sale of investments	(12,458)	(3,501)
Unrealized capital gain (loss)	-	1
Investments, end of year	-	12,370

The Balancing Pool held \$12.4 million in fixed income securities at December 31, 2017.

10. Finance Expense

<i>(in thousands of dollars)</i>	2018	2017
Interest expense	16,086	3,362
Accretion expense	331	195
	16,417	3,558

11. Trade Payable and Other Accrued Liabilities

<i>(in thousands of dollars)</i>	2018	2017
Trade payables	128,258	199,647
Accrued liabilities – Greenhouse gas obligation	82,046	215,124
Accrued liabilities – PILOT refunds (Note 15)	28,047	82,854
Accrued liabilities – Retroactive line loss adjustment	45,536	42,470
Accrued liabilities – Other	21,470	21,618
	305,357	561,713

The accrued liability for greenhouse gas obligations reported at December 31, 2018 has declined from the accrued liability reported at December 31, 2017 due to the termination of the Sundance B, C and Battle River 5 PPAs and the timing of when the obligation is settled. The amount reported for 2018 represents 2018's fourth quarter obligation, while the amount reported for 2017 represents the full year's obligation.

12. Reclamation and Abandonment Provision

<i>(in thousands of dollars)</i>	H.R. Milner Generating Station	Isolated Generation Sites	Sundance A Generating Station	Total
At January 1, 2017	14,616	6,956	8,460	30,032
Net increase (decrease) in liability	(443)	154	(6,820)	(7,109)
Liabilities paid in period	(1,053)	(427)	-	(1,480)
Accretion expense	95	45	55	195
At December 31, 2017	13,215	6,728	1,695	21,638
Less: Current portion	(2,050)	(5,717)	-	(7,767)
	11,165	1,011	1,695	13,871
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 period	(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

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 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. It is estimated that these costs will be incurred in 2021. These costs have been discounted at the risk-free rate of 1.9% (2017 - 1.5%). At December 31, 2018, the provision was decreased by \$0.07 million (2017 - \$0.4 million increase) to reflect a change in the discount rate. Expenditures of \$2.9 million (2017 - \$1.1 million) were incurred in 2018.

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 \$5.5 million (2017 - \$0.4 million) were incurred in 2018. 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 1.9% (2017 - 1.5%). 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 2020. At December 31, 2018, an increase of \$0.4 million (2017 - \$0.2 million increase) was recorded to reflect a change in estimation to complete the project.

12. c) Decommissioning Costs of PPAs

Pursuant to Section 7 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. This provision does not apply to units that cease operations after December 31, 2018.

In December 31, 2018, the Balancing Pool recorded a \$10.2 million increase (2017 - \$6.8 million decrease) to the provision for decommissioning the PPAs. In December 2018, TransAlta Corporation ("TransAlta") submitted an application to the AUC to decommission Sundance unit A. The provision for Sundance A is based upon management's best estimate of decommissioning costs. Estimated decommissioning costs were discounted at 1.9% (2017 - 1.5%).

13. Other Long-Term Obligations

(in thousands of dollars)	Genesee	Battle River 5	Sundance A	Sundance B	Sundance C	Keephills	Sheerness	Total
At January 1, 2017	542,453	151,921	46,815	134,250	148,612	256,005	463,717	1,743,773
Net increase (decrease) in liability	(265,424)	32,024	33,208	61,388	46,144	(114,800)	(217,027)	(424,487)
Losses	(129,082)	(69,947)	(80,023)	(99,677)	(86,098)	(71,621)	(125,117)	(661,565)
At December 31, 2017	147,947	113,998	-	95,961	108,658	69,584	121,573	657,721
Less: Current portion	(83,050)	(113,998)	-	(95,961)	(108,658)	(50,473)	(76,933)	(529,073)
	64,897	-	-	-	-	19,111	44,640	128,648
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

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 (2017 - \$46.22/MWh for 2018, \$54.97/MWh for 2019 and \$54.67/MWh for 2020), the unavoidable costs of meeting the obligations under the PPAs is expected to exceed the economic benefits derived from the PPAs. As a result, onerous contract provisions have been recognized and measured at the lower of the present value of continuing the PPAs and the expected costs of terminating them. Cost of termination includes 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, the minimum six-month notice period is 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 (2017 - \$1.3 billion for Genesee, Keephills, Sheerness, Sundance B, Sundance C and Battle River 5). The estimated future costs for the three PPAs were discounted at 1.9% (2017 - 1.7%).

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.

See Note 15, Contingencies and Commitments, for additional information with respect to subsequent negotiation of settlement agreements related to the Attorney General of Alberta's lawsuit.

14. 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)		
	2018	2017
Deferral account, beginning of year	(1,280,998)	(1,966,788)
Change to the Balancing Pool deferral account	334,542	685,790
Deferral account, end of year	(946,456)	(1,280,998)

In December 2017, the Board of Directors approved a 2018 consumer collection of \$3.10/MWh for a total collection from electricity consumers of \$189.2 million in accordance with the *Balancing Pool Regulation*. In October 2018, the Board of Directors approved a 2019 consumer collection of \$2.90/MWh for an estimated total collection from electricity consumers of \$180.0 million in accordance with the *Balancing Pool Regulation*.

As a result of the Balancing Pool's adoption of IFRS 15, *Revenue from contracts with customers*, on January 1, 2017, the consumer collection is recorded in revenue.

15. Contingencies and Commitments

Terminated Power Purchase Arrangements

On March 8, 2018, the Government of Alberta reached a settlement agreement with the former Buyer of the Battle River 5 PPA and Keephills PPA bringing a conclusion to the Attorney General of Alberta's application with the Alberta Court of Queen's Bench. As a result of the settlement agreement, the Balancing Pool received a reimbursement of \$5.0 million worth of emission credits, recognized as intangible assets, and remitted \$5.0 million to the former Buyer of the Battle River 5 and Keephills PPAs for historical dispatch services rendered.

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 has disputed the termination payment. The additional amount under dispute is \$56.2 million.

The Battle River 5 PPA was terminated effective October 1, 2018. A termination payment of \$61.7 million was issued to ATCO. ATCO intends to dispute the payment. The additional amount under dispute is \$7.4 million.

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 \$11.9 million to decommission Sundance A.

Payments In Lieu of Tax

Alberta Tax and Revenue Administration had issued notices of re-assessment for several tax years (dating back to 2001) to a municipal entity that has been subject to PILOT. The municipal entity had disagreed with many aspects of the notices of re-assessment and filed notices of objection for those tax years. The municipal entity proceeded with litigation to resolve the various tax matters. A number of these matters were resolved in 2016 through negotiated settlement and through the Court of Queen's Bench, resulting in a refund of \$96.0 million to the municipal entity. The refund of \$96.0 million was reflected as Other income (expense) from operating activities in 2016 and accrued in trade payable and other accrued liabilities. Alberta Tax and Revenue Administration appealed the Court of Queen's Bench decision.

In 2017, the Balancing Pool issued PILOT refunds of \$43.5 million to the municipal entity in relation to the accrued refund of \$96.0 million, leaving a balance payable of \$52.5 million.

A provision of \$30.3 million was also recorded in relation to other disputed matters that were not advanced to the courts by the municipal entity. The provision was reflected as Other income (expense) from operating activities in 2016 and accrued in trade payable and other accrued liabilities.

The total amount accrued for all disputed matters related to the municipal entity at December 31, 2017 was \$82.8 million.

In April 2018, the Court of Appeal of Alberta overturned the Court of Queen's Bench decision. The municipal entity appealed the decision to the Supreme Court of Canada. In February 2019, the Supreme Court of Canada dismissed the appeal.

During 2018, the municipal entity also negotiated a settlement with Alberta Tax and Revenue Administration in relation to the other disputed matters that were not advanced to the courts by the municipal entity.

As a result of the Supreme Court of Canada dismissing the appeal and the negotiated settlement reached on the remaining matters, \$54.8 million was reversed from the previously accrued refund leaving a balance payable of \$28.0 million to the municipal entity at December 31, 2018.

In addition, the municipal entity remitted \$70.8 million to the Balancing Pool for outstanding amounts assessed by the Alberta Tax and Revenue Administration in relation to the disputed amounts as a result of the dismissal by the Supreme Court of Canada.

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 methodology dating back to 2006. On December 19, 2018 the Court of Appeal ruled that the AUC does indeed have the jurisdiction and authority to retroactively adjust the line loss factors and the methodology.

The AUC was presented with three different methodologies for calculating retroactive line loss adjustments. The first was the AESO methodology based on Incremental Loss Factor with load scaling; the second was the AUC methodology ("Module B") based on Incremental Loss Factor with generation scaling, the third method was a methodology developed by Maxim Power Corporation. A description of the various methodologies can be found in the AESO's exhibits presented in 790-140.3 of the AUC Proceeding 790.

In December 2017, the AUC reached its decision, whereby the AUC ruled that the Module B methodology will be used to calculate retroactive line loss adjustments. The AUC also ruled that the original system transmission service contract holder will be responsible for the retroactive line loss adjustments.

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 \$45.5 million (2017 - \$42.5 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, the Balancing Pool estimates may be higher or lower than the current estimate reflected in these financial statements.

16. Cost of Sales

<i>(in thousands of dollars)</i>	2018	2017
Cost of power purchase arrangements and power marketing	1,240,067	1,283,106
Losses on PPAs recorded against other long-term obligations	(322,268)	(661,565)
Gain on the retirement of emission credits	(74,610)	-
Amortization and depreciation on assets	23	30
	843,212	621,571

Included as a reduction to cost of sales is a gain on the retirement of emission credits in the amount of \$74.6 million (2017 - nil). 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.

17. 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)	2018	2017
Salaries and other short-term employee benefits	627	643
Total	627	643

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, 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

At December 31, 2018, the Balancing Pool had \$915.3 million (2017 – \$566.3 million) in short-term discount and long-term notes issued to the Government of Alberta, including accrued interest of \$7.1 million (2017 – \$0.4 million).

The discount note that matured on January 4, 2019 was paid. The discount notes that matured on January 31 and February 6, 2019 were re-financed.

Directed by the Minister of Energy, the Balancing Pool is mandated to make payments for the Office of the Utilities Consumer Advocate (“UCA”) to cover 80% of their annual operating costs and 100% of the annual costs for the Transmission Facilities Cost Monitoring Committee (“TFCMC”) and the Retail Market Review Committee (“RMRC”).

In 2018, the Balancing Pool expensed \$5.2 million (2017 – \$5.0 million) for the UCA and \$0.7 million recovery (2017 – \$1.2 million expense) for the TFCMC and RMRC in aggregate.

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 2018, the Balancing Pool collected \$189.2 million (2017 – \$66.0 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 2018 the Balancing Pool received \$965.2 million related to the sale of electricity for the PPAs.

18. Subsequent Events

The Balancing Pool paid the short-term discount note that matured on January 4, 2019 in the amount of \$91 million.

The last remaining small power producer contract expired on February 15, 2019.

Other Financial Information

Annual Report Extracts and Other Statutory Reports

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 with the Public Interest Disclosure Office pertaining to the Department of Energy from the period April 1, 2018 to March 31, 2019.

Note: Alberta Energy Regulator, Alberta Petroleum Marketing Commission, Alberta Utilities Commission, and the Balancing Pool are considered separate entities for the purpose of the Act and therefore have individual reporting obligations.

