Energy

Annual Report
2015-2016

Government

Note to Readers:
Copies of the annual report are available on the Energy website
www.energy.alberta.ca

Energy
9945 - 108 Street
Edmonton, AB T5K 2G6

Phone: 780-427-8050
Fax: 780-422-1123

JUNE 2016

Energy

Annual Report
2015-2016

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 20 ministries.

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

This annual report of the Ministry of Energy contains the minister's accountability statement, the audited consolidated financial statements 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 and the Post-closure Stewardship Fund;**
- **other financial information as required by the *Financial Administration Act* and *Fiscal Planning and Transparency Act*, either as separate reports or as a part of the financial statements, to the extent that the ministry has anything to report; and**
- **financial information relating to trust funds.**

Minister's Accountability Statement

The ministry's annual report for the year ended March 31, 2016, was prepared under my direction in accordance with the *Fiscal Planning and Transparency Act* and the government's accounting policies. All of the government's policy decisions as at June 6, 2016 with material economic or fiscal implications of which I am aware have been considered in the preparation of this report.

Original signed by Honourable Margaret McCuaig-Boyd
Minister of Energy

Message from the Minister of Energy

Alberta's energy resources are the foundation of our prosperity and will remain a great opportunity for our province and Albertans, who own them. Our job is to ensure Alberta is a leader in environmentally sustainable resource development and that our resources provide optimal benefits for current and future Albertans.

While this last year has brought many challenges – depressed oil and gas prices and a limited market for our energy resources – it has also been a year of many successes.

In January 2016 we released the Royalty Review Advisory Panel Report, Alberta at a Crossroads, with all recommendations accepted for a modernized royalty framework for Alberta's crude oil, liquids and natural gas. We have already made great progress acting on these recommendations to establish a simpler, more transparent and efficient system that increases returns to Albertans over the long run, encourages job creation and investment, and rewards innovation.

To demonstrate that Alberta is a world leader in the fight against climate change, in November 2015, Premier Notley announced Alberta's Climate Leadership Plan. We are reducing greenhouse gas emissions by putting a price on them and implementing a hard emissions cap on oil sands production. We are dramatically cutting methane emissions. This plan will not only reduce greenhouse gas emissions but it demonstrates to the world that we are leaders in protecting the environment, protecting our health and preserving our economy for future generations.

A key component of our Climate Leadership Plan is to phase out emissions created from coal-fired electricity generation by 2030 and transition to more renewable energy and natural gas generation. Greater investment in renewable energy projects through the Renewable Electricity Program will help us work towards a cleaner energy future, diversify our economy and create good-paying jobs.

The actions we are taking under the new Climate Leadership Plan have allowed for the discussion around market access to be more positive. Sustainable resource development includes modern, carefully regulated and carefully monitored pipelines in order to get our energy resources to new markets abroad and our government has actively supported market access opportunities such as the Energy East Pipeline and the Trans Mountain Expansion.

As Minister of Energy, I actively fostered and built new relationships across Canada and globally by meeting with key stakeholders such as federal, provincial and foreign government officials, energy industry members, business community members, Indigenous peoples and academia to attract investments, advance energy market access opportunities and highlight Alberta's commitment and actions as a responsible energy producer. Alberta also played a key role in the Canadian Energy Strategy, which Canada's premiers agreed to in July 2015. The strategy serves as a framework to foster greater collaboration between provinces and territories on energy issues for the benefit of all Canadians.

As part of our government's continued action to create jobs, attract investment and diversify Alberta's economy, we announced the Petrochemicals Diversification Program which encourages companies to invest in the development of new Alberta petrochemical facilities by providing up to $500 million in incentives through royalty credits. We expect this program, which takes advantage of our abundant natural resources, to incent up to $5 billion of new investment in the province and create several thousand new jobs for Albertans.

For many Albertans these are tough times. While we cannot control the global price of oil and gas, we can control how we react to it. Alberta has experienced lows before and we have always managed to bounce back. By working together we can, and are, meeting challenges head-on and turning many of them into opportunities. Energy will play a central role in our economy – and in Canada's economy – for many decades to come.

Original signed by Honourable Margaret McCuaig-Boyd
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

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 consolidated financial statements 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 consolidated financial statements and performance results. The consolidated financial statements and the performance results, of necessity, include amounts that are based on estimates and judgments. The consolidated financial statements are prepared in accordance with 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 measures preparation are applied consistently for the current and prior years' results.
- Completeness – goals, performance measures and related targets match those included in the Ministry's Budget 2015.

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, the Minister of Finance and the Minister of Energy 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 Coleen Volk
Deputy Minister
Department of Energy

Original signed by Jim Ellis
President and CEO
Alberta Energy Regulator

Original signed by Willie Grieve
Chairman
Alberta Utilities Commission

Original signed by Richard Masson
Chief Executive Officer
Alberta Petroleum Marketing Commission

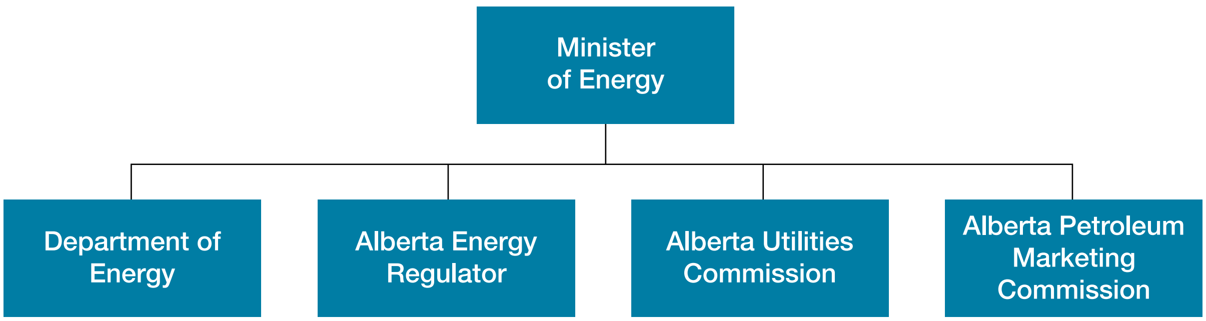
Date: June 6, 2016

Results Analysis

Ministry Overview

The Ministry of Energy manages Alberta's energy resources to help 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 and the responsible development and the wise use of energy. Sustained prosperity includes having regard for the social, economic and environmental impacts of Alberta's resource development.

The ministry consists of the Department of Energy, the Alberta Energy Regulator, the Alberta Utilities Commission, the Alberta Petroleum Marketing Commission and the Post-closure Stewardship Fund. Each entity plays important roles in overseeing the orderly development of Alberta's energy resources.



The desired outcomes in Energy's 2015-18 Business Plan are:

- Albertans benefit from responsible energy and mineral development and access to global markets;
- Effective stewardship and regulation of Alberta's energy and mineral resources; and
- Albertans benefit from safe and reliable energy-related infrastructure and innovative energy technologies.

Department of Energy

- Acts as the steward of Alberta's energy system on behalf of all Albertans
- Develops policy and manages development of Alberta's non-renewable resources, such as natural gas, oil, oil sands, coal, petrochemicals and renewable energy
- Ensures the integration of natural resource policies and serves as an interface between policy development and policy assurance
- Grants industry the right to explore and develop Alberta's energy and mineral resources
- Establishes, administers and monitors the effectiveness of Alberta's royalty systems regarding 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

Alberta Energy Regulator

- Independently makes decisions regarding resource development in accordance with applicable legislation 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

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 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 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
- Develops commodity prices used in royalty calculations
- Assists with the development of new energy markets and transportation infrastructure
- Manages the implementation of Alberta's Bitumen Royalty in Kind policy

Non-Renewable Resource Revenue

Energy and mineral resource development in Alberta is a key provider of jobs, business opportunities and tax 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.

Royalties are payments to Albertans for hydrocarbons that are produced and sold from the province's resources. Albertans, as owners, collect value from our resources through royalties. Developing Alberta's resources requires a partnership between the province and energy companies. The price received and the costs involved in producing and selling those resources affect the amount of value available for royalties.

The Government of Alberta's 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 Canada-US 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.

Non-Renewable Resource Revenues Collected

For the benefit of Albertans, the ministry accurately calculates and fully collects revenues from energy royalties and sales bonuses. This work supports Desired Outcome One: Albertans benefit from responsible energy and mineral development and access to global markets.

The following table is a comparison of the actual revenue collected and the budgeted revenues.

Revenue ($ Millions)	2015-16 Budget	2015-16 Actual
Bitumen	1,547	1,223
Crude oil	536	689
Natural Gas and By-products	343	493
Bonuses and Sales of Crown leases	181	203
Rentals and fees	145	167
Coal	15	14
Non-Renewable Resource Revenue	2,767	2,789

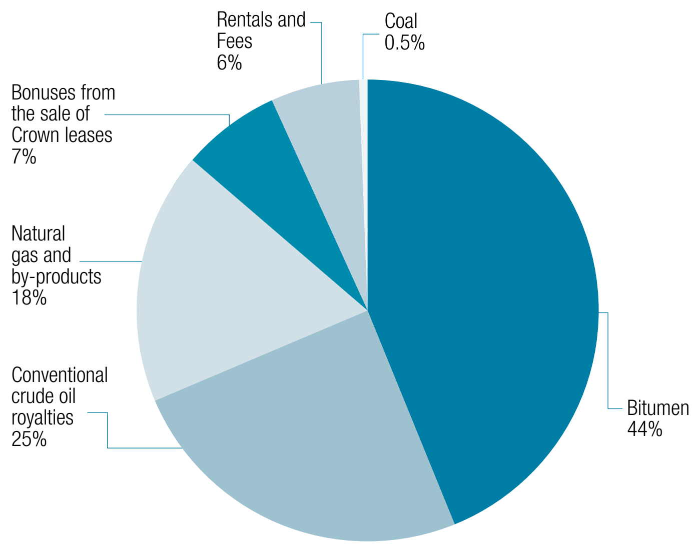
For the seventh fiscal year in a row, **bitumen** royalty made the largest contribution to provincial resource royalty revenue. In 2015-16, bitumen revenue accounted for $1.22 billion, or about 44 per cent of the non-renewable resource revenue of $2.8 billion. Bitumen royalties were lower than budgeted due to lower crude oil prices. The effect of the lower than expected oil prices reduced royalties by lowering revenue and net income of projects. This was the cause of the lower than budgeted royalties.

Conventional crude oil royalties contributed $689 million, about 25 per cent to non-renewable resource revenue in 2015-16. Conventional crude oil royalties were higher than budgeted due to the improved light-heavy differential, which increased the medium, heavy, and ultra-heavy oil prices resulting in higher conventional royalty rates than anticipated. In addition, a weaker Canadian dollar and the lower than budgeted costs of oil royalty programs and revisions to past years results filed by industry meant that conventional oil royalties were higher than budgeted.

The third largest source of resource revenue was **natural gas and by-products** royalties, which brought in $493 million. Royalties for natural gas and by-products were above budget. Lower gas prices were more than offset by higher than forecasted production and revised lower estimates for the cost of processing the Crown's royalty share of gas, and industry filings for the past fiscal years.

In 2015-16, $203 million was collected from **bonuses and sales of Crown leases**. The forecast for the petroleum and natural gas price per hectare relies on a statistical model using the forecasted oil and gas price and production and industry cash flow. A statistical time series model is used to forecast the number of hectares that will be sold. The petroleum and natural gas bonus payments were $204 million, compared to the budget forecast of $178 million. The average price per hectare was $158.64 compared to the budget forecast of $125.93/hectare, while about 129,000 fewer hectares than budgeted were sold. Oil sands sales totaled $2 million, in line with the budget. Oil sands average price per hectare was $42.30 compared to the budget forecast of $56.64. Adjustments due to Crown agreements reduced bonus and sales of Crown leases by $3 million.

Total Non-Renewable Resource Revenue 2015-16: $2.8B



Revenue from **rentals and fees** was $167 million in 2015-16. Rentals and fees revenue was higher than budgeted as more hectares were retained by industry than budgeted, and fees for mineral activities were also higher than budgeted.

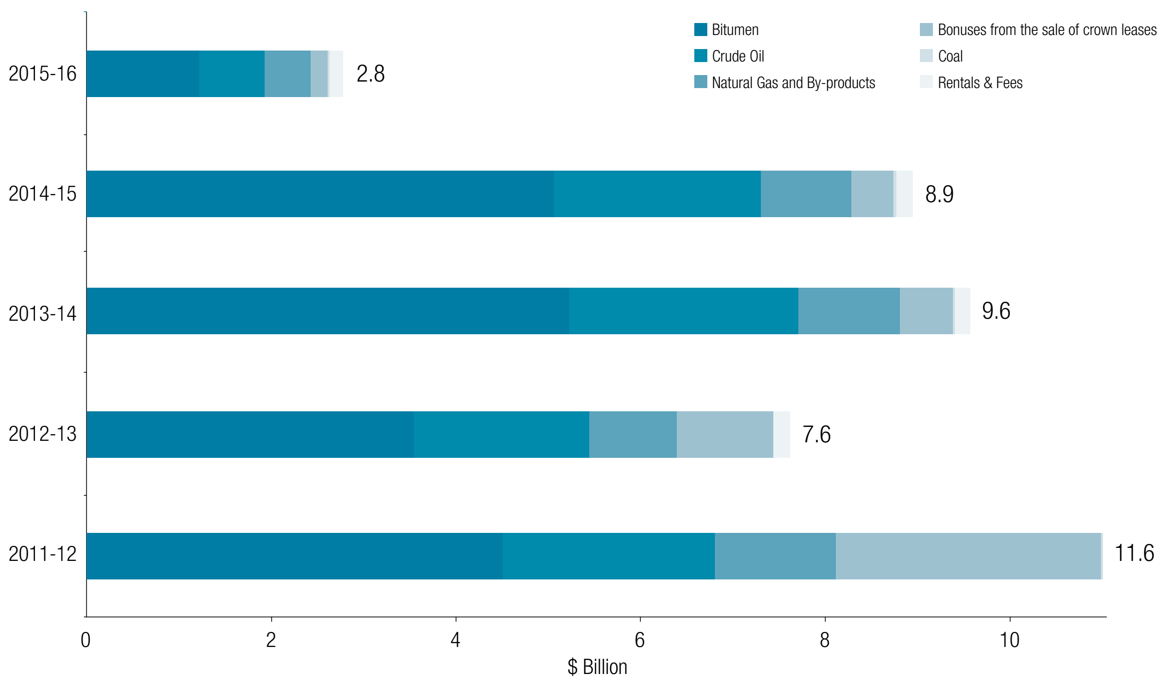
In 2015-16, revenue from coal royalty was $14 million. **Coal** royalty was lower than budgeted due to low subbituminous coal prices.

Non-Renewable Resource Revenue Trend

In 2015-16, the province witnessed the lowest non-renewable resource revenue of about $2.8 billion, compared to an average of $9.3 billion over the past five years. Notably, the decline in total non-renewable resource revenue as a whole was primarily driven by a combined decline in bitumen and conventional oil royalties, both of which were heavily impacted by the decline in oil prices worldwide.

It should be noted that despite variations, over the past five years, bitumen consistently accounted for the largest portion of non-renewable resource revenue in Alberta, fluctuating between 39 per cent of the non-renewable resource revenue in 2011-12 and 56 per cent in 2014-15. Bitumen royalty revenue experienced the largest decline of all sources of non-renewable resource revenue, both in terms of percentage decline and absolute amount. Bitumen was still by far, the largest source of royalty revenue in all five years.

Non-Renewable Resource Revenue, 2011-12 to 2015-16



Royalty Forecast

The department is responsible for the forecast of non-renewable resource revenues for the Government of Alberta.

Non-renewable resource revenue is forecasted at $1.4 billion in 2016-17, which is $1.4 billion or about 50 per cent lower than in 2015-16 and 85 per cent lower than in 2014-15. This accounts for 3.3 per cent of total Government of Alberta revenue in 2016-17 and is forecasted to grow to 8.5 per cent in 2018-19. Most of the deterioration in non-renewable resource revenue is due to the impact of falling global prices on bitumen and crude oil royalties.

Non-renewable resource revenue is forecasted at $1.4 billion in 2016-17, $2.8 billion in 2017-18 and $4.2 billion for 2018-19, with substantial growth in bitumen royalties, mainly due to the slow improvement in oil prices and rising production.

The department has a complex system in place to develop non-renewable resource revenue forecasts. It considers multiple price forecasts and an analysis of market fundamentals to ensure consistency for the entire spectrum of markets - from global to North America to Alberta. The non-renewable resource revenue forecast can change frequently throughout the year as new price and production forecasts are issued. When the market is changing rapidly, price outlooks are frequently updated and the department 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.

Understanding Commodity Prices

Prices differ depending on crude quality and access to markets. Presently, Brent crude oil from the North Sea is considered the global price benchmark for light sweet oil, given its ability to reach global markets.

The West Texas Intermediate (WTI) is the North American price benchmark for light sweet oil. Similar to Brent, WTI can currently get international market access via tide water (it is no longer land-locked) as the United States export ban was lifted in December 2015.

Western Canadian Select (WCS) is a North American price benchmark for heavy crude oil, commonly used to price Canadian heavy oil.

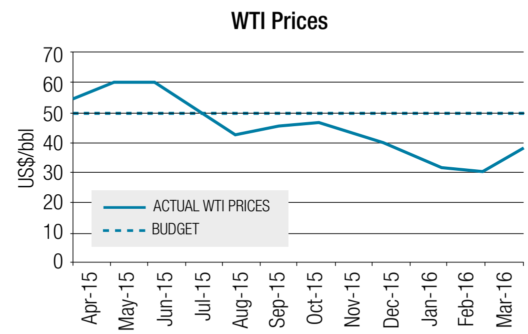
The difference between the WTI and WCS prices is the light-heavy differential. The differential is affected by differences in crude quality between light sweet and heavy sour oils, location, market demand for heavy crude, and by access to markets for these products. When oil pipelines leaving Canada reach full capacity, Canadian oil prices are discounted and receive a bigger price reduction compared to WTI. This reduces the royalty revenue received by Albertans.

The Alberta reference price for natural gas is used in natural gas royalty formulas and determines the royalty rate that will be applied to natural gas. Overall, the general rule of supply/demand balance determines natural gas prices in North America. Moreover, storage levels and weather patterns affect this price 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.

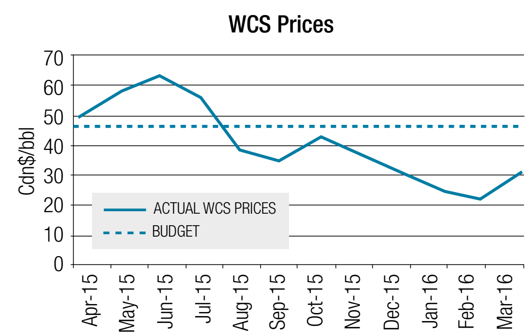
Changes in Commodity Prices during 2015-16

The international drop in crude oil prices was the most significant factor impacting non-renewable resource revenue as it affected both the determination of the royalty rate that is applied to companies' revenue and the companies' revenue itself. Lower royalty rates take effect in a low-price environment.

Selected indicators for budgeting purposes	2015-16 Budget	2015-16 Actual
WTI (US$/bbl)	50.00	45.00
Exchange rate	US$0.78	US$0.76
Light-heavy differential (US$/bbl)	13.60	13.40
WCS (Cdn $/bbl)	46.50	40.86
Alberta reference price for natural gas (Cdn$/GJ)	2.60	2.21

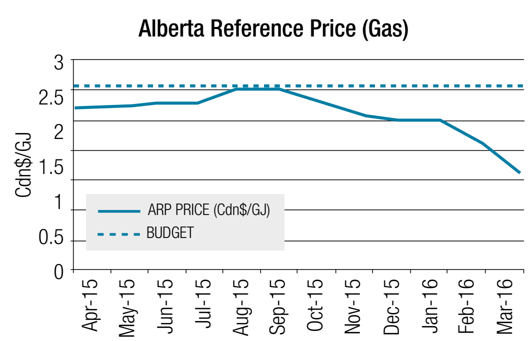


Budget 2015 was based on a US$50.00 per barrel price for WTI crude oil and a 78 cent Canada-US exchange rate. The actual 2015-16 WTI price was US$45.00 per barrel based on the average of the monthly prices during the fiscal year and the actual Canada-US exchange rate was 76 cents. Crude oil prices recovered gradually after the beginning of the fiscal year with WTI prices stabilizing at around US$60 per barrel in May and June 2015. However, crude prices declined again after July 2015 as a persistent global oversupply, continuing build-ups in global inventories and concerns over demand growth put significant downward pressure on prices.



The forecasted light-heavy differential was US$13.60 per barrel, resulting in a WCS price of Cdn$46.50 per barrel. The actual light-heavy differential was US$13.40 per barrel, which was not significantly different from the forecast. The WCS price averaged Cdn$40.86 per barrel in fiscal year 2015-16.

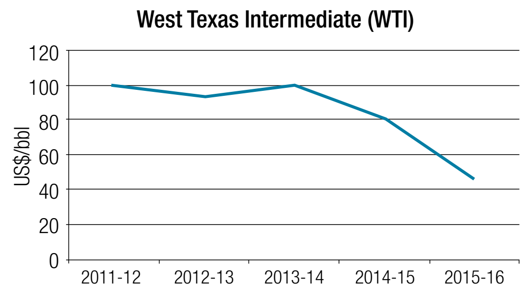
The WCS price was lower than budgeted mainly due to lower than expected WTI prices. The global oversupply of crude that started in the second half of 2014-15 continued into 2015-16. Crude oversupply coupled with Organization of Petroleum Exporting Countries' decision not to cut production resulted in significantly lower WTI price, which drove down the WCS price.



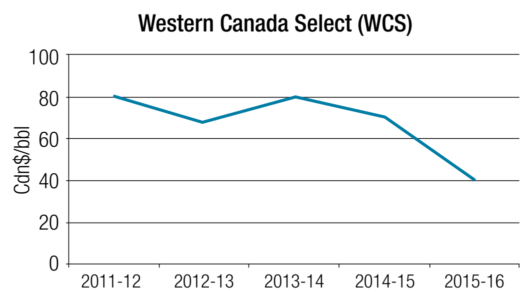
Royalties in *Budget 2015* were based on a gas price forecast of Cdn$2.60/gigajoule (GJ) for the Alberta natural gas reference price. The Alberta natural gas reference price averaged Cdn$2.21/GJ in in 2015-16 fiscal year. The actual gas prices were below budgeted levels at the end of the fiscal year due to combined impact of a much warmer than expected winter and robust United States and Canadian production that kept storage levels more than adequate for the 2015-16 heating season. Thus, prices decreased significantly towards the end of the fiscal year.

Commodity Price Trends

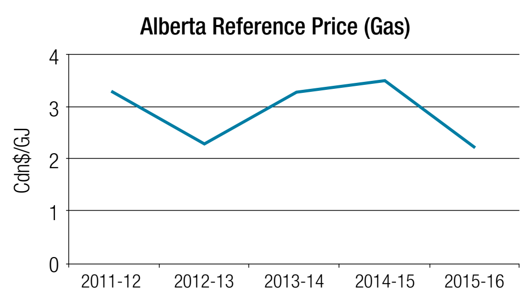
Energy commodity prices have changed significantly over the last five years. West Texas Intermediate (WTI), Western Canada Select (WCS) and the Alberta Reference Price (ARP) for gas have all seen a considerable decline in prices in 2015-16.



The WTI saw a substantial decline in prices from US$98.83 per barrel in 2011-12 to a five year low of US$46.50 per barrel in 2015-16, with an average price of US$84.29 per barrel over the last five years. The 2015-16 low of $US46.50 per barrel was a considerable drop in prices from the reported five year high in 2013-14 of US$100.55 per barrel of oil. The decline in WTI prices is a combination of a number of factors, such the persistent global oversupply, continuing build-ups in global inventories and concerns over demand growth put significant downward pressure on prices.



The WCS saw a considerable decline in prices from Cdn$79.99 per barrel in 2011-12 to Cdn$40.86 per barrel in 2015-16. The WCS price peaked to a high of Cdn$80.11 in 2013-14, with an average of Cdn$68.04 per barrel over the five year period. The significant decline in WCS prices follows the global crude oil prices trend in 2015-16. 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, a weaker Canadian dollar over the past two fiscal years has mitigated some effects of declines in crude oil prices denominated in US dollars.



The ARP in 2015-16 was $2.21 per GJ, which decreased $1.30/GJ from last year's price of $3.51/GJ. The 2015-16 ARP is almost at the same level of as in 2012-13. This decrease in price is due to downward pressure of long-term structural supply/demand changes; as well as the demand for natural gas has been lagging behind supply due to abundant supply of the U.S. shale gas. Natural gas prices could be still volatile especially in the short term due to storage and weather impacts. For example, despite the abundant supply from the northeastern U.S. shale gas producing regions that keep flooding the North American market with low cost supply, the ARP prices in 2013-14 experienced uplift pressure due to extreme cold winter of 2013-14 that drained storage level across North America to a record low, thus provided strong support to natural gas prices.

Other key factors that affect royalty revenues

Exchange rates: A lower Canadian dollar increases royalty revenue as WTI prices are set in United States dollars and increase when converted into Canadian dollars. Royalty revenue decreases when the exchange rate increases.

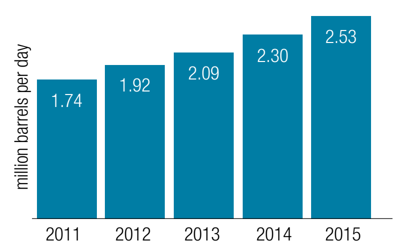
Cost increases and inflation: Oil sands royalties are based on project revenue minus cost. Inflation and increases in capital and operating costs lead to lower bitumen royalty revenues.

Production forecasts: Production forecasts are impacted by crude oil prices. Higher prices lead to higher forecasted production while lower prices have the opposite effect. Production disruption in any one of the major projects can have a significant impact on royalties.

Production Trends

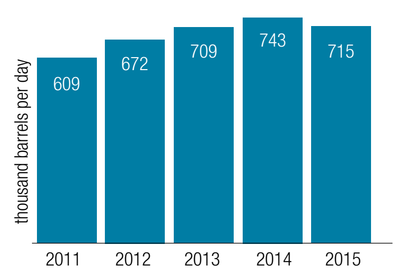
During 2015, the international oil price decline had a much more significant impact on conventional oil than on the oil sands. In fact, crude bitumen production increased from 2.3 million barrels per day (bbl/d) in 2014 to 2.5 million bbl/d in 2015, and therefore continued an escalating trend that has been underway since 2008. Most of the production increase was due to the start-up of oil sands projects that were sanctioned and started construction prior to the decrease in oil prices. The share of crude bitumen production as a percentage of global consumption also increased in 2015 to 2.7 per cent from 2.5 per cent in 2014.

Alberta Crude Bitumen Production

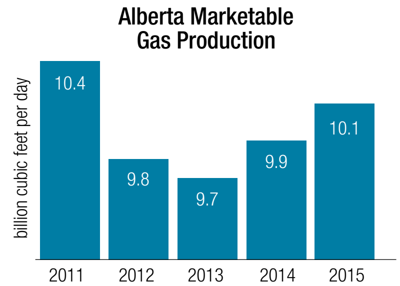


Production of conventional crude oil and equivalent (condensate and pentanes plus) decreased from about 743 thousand bbl/d in 2014 to 715 thousand bbl/d in 2015, a four per cent decline. Notably, conventional production declined by 10 per cent from 2014 to 2015, from 590 thousand bbl/d to 530 thousand bbl/d. The decline in conventional oil production was to some extent counterbalanced by a significant increase in condensate and pentanes plus production, which went up by 20 per cent from 153 thousand bbl/d in 2014 to 184 thousand bbl/d in 2015. The overall increase in condensate and pentanes plus was influenced by two main factors: increased demand as it was used as a diluent for the transportation of non-upgraded bitumen production; and, producers focused on liquids-rich areas in the province such as the Duvernay and Montney formation to compensate for otherwise low natural gas prices and capture the added value of Natural Gas Liquids.

Alberta Conventional Crude and Equivalent Production



Marketable natural gas production increased from 9.9 billion cubic feet per day (Bcf/d) in 2014 to 10.1 Bcf/d in 2015, a two per cent increase despite relatively low gas prices in 2015. This was a result of a lagged effect stemming from high drilling levels in 2014 and a strong demand from the oil sands and electricity sectors. Marketable gas production in the province was generally down throughout the province, with the exception of output in the Duvernay and Montney formations supporting the overall year-over-year increase.



*The Alberta Energy Regulator has modified the methodology and format of ST-3 Gas Report effective January 2013 production month.

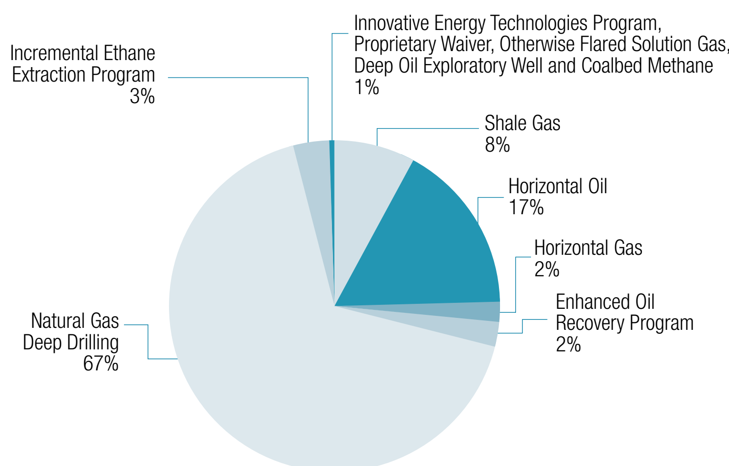
Royalty Programs

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 revenue and numerous other benefits to the provincial economy. This work supports Desired Outcome One: Albertans benefit from responsible energy and mineral development and access to global markets.

The Government of Alberta undertook a review of the royalty system in 2015-16. Recommendations to modernize the royalty system were announced and accepted on January 29, 2016. Additional information about the Royalty Review work appears on page 24 of this report. As the province's royalty system was under review in 2015-16, the department continued to manage the current royalty framework, including a number of existing royalty programs.

Royalty programs are developed by the department for a number of reasons such as to attract investment in Alberta's energy resources and to encourage new energy technologies and processes. Royalty programs

ROYALTY PROGRAMS



TOTAL ROYALTY ADJUSTMENTS
$850.9 million

Royalty Programs	2015-16 ($million)
Natural Gas Deep Drilling	$ 573.0
Horizontal Oil	$ 140.9
Shale Gas	$ 65.8
Incremental Ethane Extraction	$ 25.2
Enhanced Oil Recovery	$ 21.0
Horizontal Gas	$ 16.4
Innovative Energy Technologies	$ 4.5
Proprietary Waiver	$ 3.8
Otherwise Flared Solution Gas	$ 0.2
Deep Oil Exploratory Well	$ 0.1
Coalbed Methane	$ 0.02
Total Royalty Adjustments	**$ 850.9**

increase the province's overall royalty revenues by providing incentives to companies for recovering energy resources from existing locations that may not have been economically recoverable otherwise. In 2015-16, 11 royalty programs provided over $850.9 million in royalty adjustments to oil and gas producers.

Natural Gas Deep Drilling Program

The Government of Alberta has had various royalty programs for deep natural gas development since 1985. The Natural Gas Deep Drilling Program was introduced in January 2009 and was modified in May 2010 to increase the overall effectiveness of the program and make it an ongoing feature of the Alberta Royalty Framework.

The intent of the Natural Gas Deep Drilling Program is to encourage the development of new exploration and production from deeper natural gas wells that are more costly to drill and complete than shallower wells. Encouraging the development of deep natural gas wells is important to Albertans because these wells contribute a disproportionately larger share of royalty revenues from natural gas production compared to shallower wells. The program is intended to enable producers to develop deep gas resources that are more costly to access, which offer the greatest resource potential.

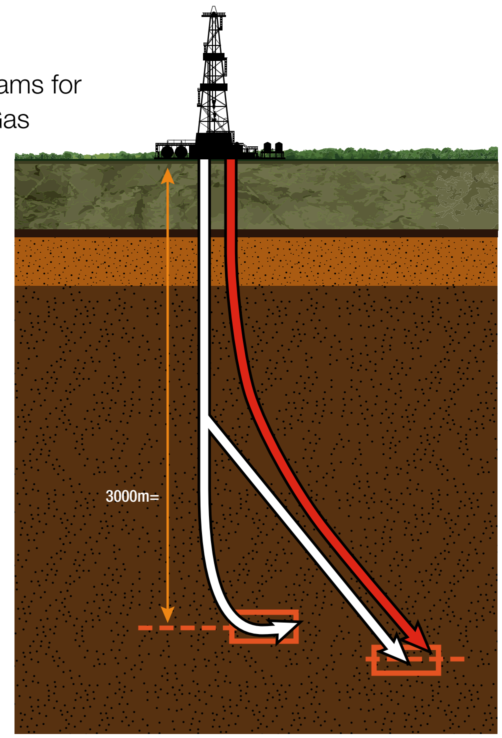


Figure 1: Deep drilling has a true vertical depth greater than 2000m

The Natural Gas Deep Drilling Program provides a maximum royalty rate of five percent for natural gas for five years after the finished drilling date or until the total royalty adjustment is reached. In 2015-16, the Natural Gas Deep Drilling Program provided the largest royalty adjustment to oil and gas companies with roughly $573.0 million in royalty credits. Royalty adjustments are based on well depth.

The Emerging Resources and Technologies Initiative

The Emerging Resources and Technologies Initiative was introduced in May 2010 to stimulate investment and encourage development of Alberta unconventional resources through the deployment of new technologies. It supports new exploration, development, and production from Alberta's emerging resources such as shale development and coalbed methane. The Emerging Resources and Technologies Initiative was implemented to increase investors' ability to recover upfront investments by extending the maximum five per cent New Well Royalty Rate in four situations to acknowledge the higher costs and risks associated with these emerging resources and technologies. They are **horizontal oil**, **shale gas**, **horizontal gas** and **coalbed methane**.

The New Well Royalty Rate was introduced to remove the disincentive that the royalty framework applied to drilling new wells, while attempting to keep the other design features of Alberta's royalty formulas intact and comparable to other jurisdictions. Before the New Well Royalty Rate was a part of the royalty framework, maximum royalty rates would be applied to new wells where highest production is expected at the beginning stages. This was a big disincentive for industry to drill new wells in Alberta. The New Well Royalty Rate provides a lower up front royalty rate at the start of production to facilitate the recovery of investment costs prior to imposing a higher royalty rate. The New Well Royalty Rate does this by setting a maximum five per cent royalty for the first 12 production months, or 50,000 barrels of oil equivalent.

Horizontal Oil

The Government of Alberta recognized that a transition to horizontal drilling was occurring throughout North America and that support for this technique would improve productivity and increased resource recovery. The introduction of the Horizontal Oil New Well Royalty Rate recognizes the increased costs and risks associated with horizontal oil drilling and provides a lower upfront royalty rate at the start of production to facilitate the recovery of investment costs prior to imposing a high royalty rate. The Horizontal Oil New Well Royalty Rate provides increased benefits for increased measured depth, which is a proxy for the cost of drilling.

The Horizontal Oil New Well Royalty Rate extends the five per cent maximum royalty rate with volume and production month limits, whichever comes first. In 2015-16, the Horizontal Oil New Well Royalty Rate provided around $140.9 million in royalty adjustments.

Shale Gas

In 2012, the Alberta Energy Regulator estimated that there was roughly 29.7 billion barrels of natural gas liquids in five shale formations (Duvernay, Muskwa, Basal Banff/Exshaw, North Nordegg, and Wilrich). Shale gas production was in early stages in the province and would take a number of years to achieve commercial development of these resources.

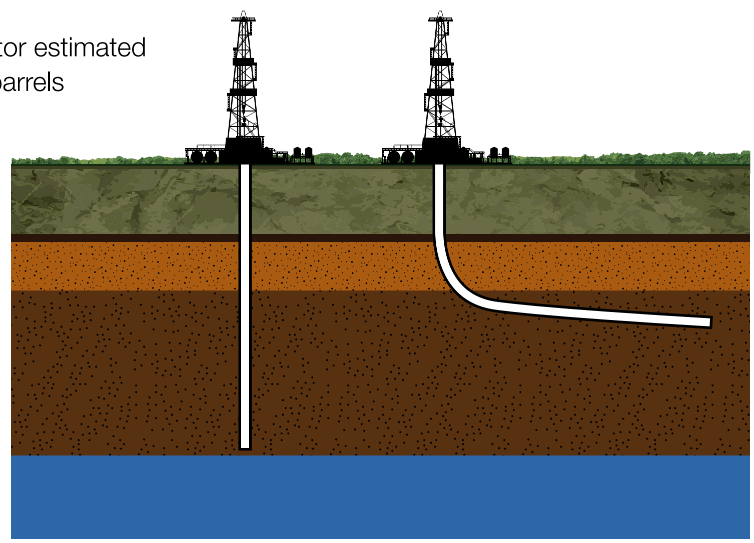


Figure 2: This picture depicts the difference between vertical drilling (left) and horizontal drilling (right)

The Shale Gas New Well Royalty Rate was designed to accelerate the acquisition of knowledge and achieve commercial production from shale deposits. Due to higher costs and lack of existing commercial development, the Shale Gas New Well Royalty Rate was designed without a volume limit and with the longest time limit of any of the Emerging Resources and Technologies Initiative rates to provide a long enough period of low royalty rates to spur shale development.

The Shale Gas New Well Royalty Rate extends the five per cent maximum royalty rate to a maximum of 36 production months, with no production volume limit. In 2015-16, the Shale Gas New Well Royalty Rate provided roughly $65.8 million in royalty adjustments.

Horizontal Gas

As a part of the Government of Alberta recognizing a transition to horizontal drilling was occurring throughout North America, the Horizontal Gas New Well Royalty Rate was introduced in May 2010 to acknowledge the increased costs and risks associated with more challenging horizontal gas drilling.

The Horizontal Gas New Well Royalty Rate was designed to be the least generous of the Emerging Resources and Technologies Initiative rates because it was determined that most horizontal gas wells would also be eligible for benefits under the Shale Gas New Well Royalty Rate, Coalbed Methane New Well Royalty Rate, and/or Natural Gas Deep Drilling Program. The Horizontal Gas New Well Royalty Rate extends the maximum five per cent royalty rate to a maximum of 18 production months, or 7,949 cubic meters of oil equivalent production, whichever comes first. In 2015-16, the Horizontal Gas New Well Royalty Rate provided around $16.4 million in royalty adjustments.

Coalbed Methane

The Alberta Geological Survey estimated that there may be up to 500 trillion cubic feet of natural gas in Alberta coals. The greatest quantity of coalbed methane is found in the coal seams which have not been widely developed. These coal seams usually contain saline water, which requires a dewatering phase that can take nine months or longer before a well achieves its maximum production rate. This dewatering phase increases costs of production and negatively impacts well economics.

The introduction of the Coalbed Methane New Well Royalty Rate acknowledges the higher costs involved in developing coalbed methane resources, as well as recognizing the depressed prices for natural gas at the time. The Coalbed Methane New Well Royalty Rate extends the maximum five per cent royalty rate to a maximum of 36 production months, or 11,924 cubic meters of oil equivalent production, whichever comes first. In 2015-16, the Coalbed Methane New Well Royalty Rate provided $21,000 in royalty adjustments.

Incremental Ethane Extraction Program

The Incremental Ethane Extraction Program (IEEP) was implemented in September 2007 with an approved budget of $350 million. The purpose of IEEP is to encourage increased petrochemical production in Alberta by providing incentives through royalty credits to offset the high capital costs of recovering incremental barrels of ethane feedstock. It is an incentive program that provides credits to petrochemical companies that consume incremental ethane and ethylene for value-added upgrading (e.g., production of higher valued products, such as ethylene, polyethylene and other derivatives).

The objective of the IEEP is to sustain and grow the petrochemical industry in Alberta through the ongoing development of a value-added strategy for Alberta and its intended purpose is to:

- encourage value-added of ethane upgrading in Alberta;
- address the tight supply of ethane in Alberta and fill existing petrochemical capacity;
- encourage new investment in ethane extraction facilities upgrades to existing plants, new plants and off-gas processing; and
- attract new investment in petrochemical derivative plants.

Royalty credits are provided to approved projects based on the amount of eligible ethane the project consumes and up to the approved amount of the project proposal. Projects can receive royalty credits for up to 60 consecutive months from the start of their operation. In 2015-16, the IEEP provided $25.2 million in royalty adjustments.

Enhanced Oil Recovery Program

The Enhanced Oil Recovery Program (EORP) was implemented in 2014 to replace the Enhanced Oil Recovery Royalty Relief Program, which had a similar policy intent and program objectives. Enhanced Oil Recovery (EOR) is a method of crude oil production that injects materials to increase oil recovery from a pool. It is used on reservoirs that have already produced oil. EOR sustains the province's economic prosperity and employment as it enables business enterprises to optimize Alberta's resource base, as they make investments to improve basin productivity.

The objective of the EORP is to enable incremental crude oil production through tertiary development resulting in increased recoverable reserves and incremental royalties for the Crown. The program provides a maximum five per cent royalty rate for all oil produced from program-approved EOR projects for a defined period of up to 120 months.

In 2014, EOR projects approved under the program contributed over $120 million to Crown royalty revenues which account for 4.8 per cent of Alberta's conventional oil revenues and 0.8 per cent of Alberta's conventional oil production. Approximately $100 million of this revenue was considered incremental royalty to the Crown that otherwise would not have been generated without the program. In 2015-16, EORP provided $21.0 million in royalty adjustments.

Innovative Energy Technologies Program

In 2004, the Government of Alberta introduced the Innovative Energy Technologies Program (IETP) program. The IETP supports development of innovative technology to enhance the production and efficiency of Alberta's oil, oil sands and gas resources and to find commercial technical solutions to the gas over bitumen issue that allow efficient and orderly production of both resources. It is a $200 million commitment by the Government of Alberta to provide royalty adjustments to pilot and demonstration projects that use innovative technologies to increase recoveries from existing reserves and encourage responsible development of oil, natural gas and in situ oil sands reserves.

The objectives of the IETP include the following:

- increasing the recovery from oil and gas deposits resulting in incremental production and royalties;
- finding a flexible commercial technical solution to the gas over bitumen issue that will allow efficient and orderly production of both resources improving the recovery of bitumen resources by in situ technologies;
- improving recovery of natural gas from coal seams; and
- disseminating technology and information developed through the projects supported by this program.

The IETP provides up to 30 per cent of the funding of a project to a maximum of $10 million. After December 31, 2016, companies involved in the IETP will no longer be able to submit new claims based on allowable costs. However, unclaimed credits that have already been earned will still remain redeemable. In 2015-16, the IETP provided $4.5 million in royalty adjustments.

Since its inception, the IETP has provided roughly $163 million in royalty abatements. In total, 42 projects have been approved and publicly announced. Of the 40 projects that proceeded:

- 16 dealt with oil sands areas;
- nine focused on oil;
- 11 were related to gas; and
- four focused on CO_2 enhanced oil recovery projects.

These projects have made a significant contribution to the timely dissemination of technical information in the energy and recovery areas of the heavy oil industry in Alberta. The learnings from these projects have assisted industry to reduce the lead time for selection and deployment of new technologies at a field scale. The IETP has also contributed to some of the largest economic and technical successes in enhanced oil recovery through its support of the first field wide polymer flood in Canada.

Proprietary Waiver

The Proprietary Waiver program has been a part of the royalty system since 1977. The original intent was expected to incent the early development of the oil sands which were considered experimental and experimental crude oil projects at the time. Currently, the program remains in place to reflect provisions of Crown agreements whereby owners of enhanced oil recovery or oil sands projects did not pay gas royalty on gas produced and used for the project. In 2015-16, Proprietary Waiver provided over $3.8 million in royalty adjustments.

Otherwise Flared Solution Gas Royalty Waiver Program

The Otherwise Flared Solution Gas Royalty Waiver Program (OFSG) has been in place since 1999. The objective of this program is to encourage a reduction in the volume of solution gas being flared or vented in the province in order to minimize the environmental impact of oil and gas development. OFSG encourages the reduction of solution gas flaring and venting that would otherwise be uneconomic to conserve.

The OFSG program has been considered royalty neutral under the assumption that solution gas under the program would not have been conserved without the OFSG royalty waiver. In 2015-16, the OFSG provided $220,000 in royalty adjustments.

Deep Oil Exploratory Well Program

The Deep Oil Exploratory Well Program (DOEW) was established in 2009. Exploratory oil wells from 2009 to 2013 could qualify for the DOEW and the program is in effect until 2018. The objective of the DOEW was to provide incentives to producers to pursue new, deeper conventional oil wells that would be marginally economic under the generic Alberta Royalty Framework.

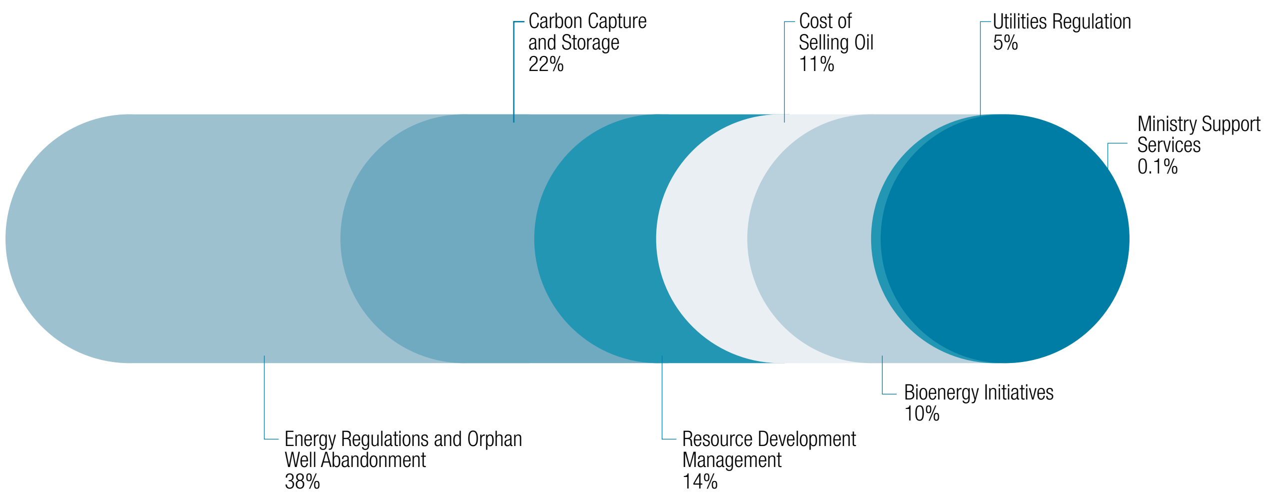
The program reduced the royalty rate for oil to zero percent for the first 12 months of production or up to $1 million dollars in royalty credits or which ever occurred first. In 2015-16, the DOEW provided $145,000 in royalty adjustments.

Ministry Expenditure Highlights

Energy's 2015-16 operating results saw a $260 million expenditure surplus from *Budget 2015*, with total operational expense of $730 million, which was a $10 million increase from 2014-15.

- The Carbon Capture and Storage program was $130 million lower than budgeted. This is a reflection of delays in the construction of the Alberta Carbon Trunk Line. The other project in the program, Quest, completed the construction and commercialization phases during 2015-16.
- The drop in global market prices for oil lead to a 70 per cent reduction in crude oil royalties compared to the previous fiscal year. As crude oil royalty is paid by industry through oil, the reduction in royalty revenue means a lower volume of oil received for sale by the province, accounting for $107 million in budget surplus.
- The 2015-16 fiscal year represents the last year for the Bioenergy Producers Credit Program, which encouraged a variety of bioenergy products, such as renewable fuels, liquid biofuels, electricity, heat and biomass pellets and gas productions. The program access was 77 per cent of the maximum available, reflective of actual production achieved by grant recipients.

Ministry of Energy Expenses by Program 2015-16, $730 million in total expenses



DESIRED OUTCOME 1

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

What this means:

For the benefit of Albertans, the ministry accurately calculates and fully collects revenues from energy royalties and sales bonuses. The ministry also reviews and maintains a competitive and effective royalty regime that attracts industry investment, which provides jobs, business opportunities, tax revenue and numerous other benefits to the provincial economy. The ministry continues to seek opportunities to increase access to global markets to strengthen both provincial and national economies.

Priority Initiatives to achieve this desired outcome included:

1.1 Support the Royalty Review Panel to optimize returns to Albertans as owners of the resource; industry investment; diversification opportunities, such as value-added processing and other innovations; and responsible development of Alberta's resources.

1.2 Build and deepen energy-related relationships nationally and globally to diversify markets for Alberta's energy resources and products.

1.3 Develop policies and conditions that support the diversification of resource value chains.

Key Achievements:

Royalty Review

On August 28, 2015, the Royalty Review Advisory Panel was announced with a mandate to identify ways to optimize returns to Albertans, continue to support industry investment, diversification opportunities, such as value-add processing, innovation or other forms of investment and responsible development of Alberta's resources.

The department supported the work of the Panel to ensure the desired outcomes and timelines of the royalty revenue were achieved. The royalty review process involved public engagement, in which tens of thousands of Albertans were engaged, as well as meetings with individuals and communities in the private, public and non-profit sector. Additionally, the work included a technical review with three Expert Groups and was supported by data analytics firms Wood Mackenzie and GLJ Petroleum Consultants. Department staff provided secretariat support throughout the review, including coordinating logistics, facilitation, managing third-party contracts, providing data and advice, as well as other support as required.

Due to the high-profile nature of the royalty review and the wide breadth in public consultations, a strong emphasis was placed on enhancing transparency and Albertans' awareness and understanding of the royalty framework, resource development processes and issues through communication materials using multi-media platforms and the website **www.letstalkroyalties.ca**.

On January 29, 2016, the Royalty Review Advisory Panel Report, Alberta at a Crossroads, was publically released and the Government of Alberta accepted all of the recommendations:

- Establish guiding principles and design criteria for Alberta's royalty framework;
- Modernize Alberta's royalty framework for crude oil, liquids and natural gas;
- Enhance royalty processes and administration for the oil sands; and
- Seize opportunities to enhance value-added processing.

The royalty review cost approximately $1.8 million to undertake over the course of five months. This included a four-member panel, four public community engagement sessions, one telephone town hall, more than 65 meetings with key stakeholder groups, and an interactive website.

Immediately following the release of the Royalty Review Advisory Panel's final report, the department began implementing the recommendations. The new royalty framework creates a simpler, more transparent and efficient system that encourages job creation and investment, rewards innovation and increases returns to the province over time. The majority of the work is expected to be completed by January 1, 2017.

Increased Market Access for Alberta's Resources

The Government of Alberta supports market access opportunities in order to gain access to new global markets. Once market access opportunities are achieved, it will capture the full value of our oil resource by reducing market-based price differentials. A key challenge facing our energy industry is the need to improve access to new global markets. Alberta's ability to access energy markets is crucial; not only for the province's energy industry but for the economic future of Canada. Every Canadian benefits from a strong energy sector through attraction of investment and job creation.

Alberta continues to be challenged by an eroded public confidence in past regulatory processes, which lacked meaningful engagement with communities affected by these projects, particularly Indigenous communities. Working in cooperation with key stakeholders, including the federal government, the Government of Alberta will continue to improve public confidence in our regulatory processes, rebuild relationships, and address challenges to market access.

In order to achieve increased market access, the ministry is committed to:

- actively participating in national pipeline regulatory processes;
- building relationships through diplomacy and working with key stakeholders,
- working with industry to ensure accuracy of information, and
- promoting one of the most progressive climate frameworks in the world.

Pipelines are the safest and most efficient way to transport oil. Over the last year, the province has driven efforts to increase market access by participating in regulatory processes on four key pipeline projects, three of which enable tidewater access. The decision to approve a major pipeline project is based on whether the project is in the public interest and is made by the federal government, based on recommendations from the **National Energy Board**. Energy intervened in, participated in or actively monitored the major market access pipeline regulatory proceedings before the National Energy Board. Energy's participation in the hearing processes is providing Alberta with key insights and ensures the National Energy Board understands the important economic benefits of the projects to Canada and Alberta.

Energy actively monitored and participated in the regulatory process for the **Enbridge Line 9 Reversal and Line 3 Replacement projects** with the National Energy Board. Enbridge's Line 9B pipeline was approved by the National Energy Board in February 2015 and became operational in December 2015. Line 9 is currently authorized to transport up to 300,000 barrels per day of crude oil into Ontario and Quebec improving Alberta's access to Eastern Canadian markets.

The **Trans Mountain Expansion Project** seeks to increase the capacity of a previously existing pipeline system, from transporting 300,000 barrels per day (bbl/d) to 890,000 bbl/d. The current system transports refined products and crude oil from Strathcona County, Alberta to Burnaby, British Columbia and to U.S. refineries in the State of Washington Puget Sound area. The expansion will increase crude oil capacity to the Westridge Dock in Burnaby, British Columbia. The Government of Alberta has intervener status in the hearing and submitted its written final argument on January 12, 2016. The submission conveyed Alberta's support for the project based on the benefits to Canada and Alberta.

The proposed **Northern Gateway Project** has a projected capacity of up to 525,000 bbl/d day and would run from Bruderheim, Alberta to Kitimat, British Columbia. On June 17, 2014, the federal government accepted the National Energy Board's recommendation that the Northern Gateway Pipeline be approved with 209 conditions.

Energy East is a 4,600 kilometer oil pipeline with a projected capacity of 1.1 million bbl/d, which would carry crude oil from Hardisty, Alberta to New Brunswick, provide access to tidewater and connect Canada with markets in Europe, Southeast Asia, and the U.S. Gulf Coast. Energy plans to participate in the National Energy Board's hearings for the Energy East Pipeline Project, ensuring the interests of Albertans are represented.

Alberta Petroleum Marketing Commission (APMC) continued to steward its 100,000 bbl/d commitment on the proposed Energy East pipeline project. As part of the shippers group, APMC provided input to TransCanada Pipelines on key decision items throughout the year.

Energy **fostered and built new relationships** across Canada by meeting with key stakeholders such as federal and provincial government officials, pipeline and rail companies, industry associations, the business community, Indigenous peoples and academia to advance oil market access to provinces across Canada. APMC continued to engage with industry participants to explore and evaluate new market access opportunities through pipeline, crude by rail and export terminal development proposals.

Recognizing that achieving strategic energy outcomes is a pan-national effort, Canada's premiers agreed to and released the **Canadian Energy Strategy** at the annual summer Council of the Federation meeting in July 2015, in St. John's, Newfoundland and Labrador. The strategy serves as a framework to foster greater collaboration between provinces and territories on energy issues for the benefit of all Canadians. In August 2015, the premier of Newfoundland and Labrador directed provincial and territorial ministers to take action on the implementation of the Canadian Energy Strategy and report back on progress of the Council of the Federation by May 31, 2016.

Four working committees were formed to implement the Canadian Energy Strategy, these committees are: Energy Efficiency, Climate Change and Transition to a Lower Carbon Economy, Delivering Energy to People, and Technology and Innovation. Alberta currently co-chairs the working committee on Climate Change and Transitioning to a Lower Carbon Economy, which explores the potential to expand the use of market-based carbon management mechanisms across Canada. Alberta has also been actively involved in all deliverables under the four committees and continues to support the implementation of the Canadian Energy Strategy. A progress report to Premiers will be tabled at the 2016 Council of the Federation summer meeting in Whitehorse, Yukon.

Energy's **international energy efforts** aim to further build Alberta's position as a reliable and environmentally responsible energy supplier, in support of increasing market access in key global markets. The department focused on strengthening market receptivity for Alberta energy products, attracting industry investment, and forming partnerships that lead to business opportunities, market access, environmental performance, and other benefits for the provincial economy. In 2015-16, Energy:

- supported 30 incoming official visits to Alberta from over 20 countries interested in engaging with the department;
- advised and facilitated the department's participation in over 13 domestic events;
- coordinated the department's participation in nine missions and international events; and
- participated in the 2015 China-Alberta Petroleum Centre's Annual Board Meeting.

APMC continued to engage and build relationships with international energy market participants in anticipation of tidewater access. APMC renewed an Expression of Intent to Collaborate with Indian Oil Corporation Limited, an Indian State Owned Enterprise.

Energy also advanced the improvement of pipeline performance and safety standards by contributing to research projects across the country. The department also worked with Natural Resources Canada in the development of measures to strengthen pipeline spill prevention, preparedness and response and liability regimes under the federal *Pipeline Safety Act*. Additionally, Energy supported the development of Clear Seas Centre for Responsible Marine Shipping, an independent research organization that provides impartial and evidence-based research about marine shipping in Canada including risks, mitigation measures, and best practices.

Energy also participated and advocated for Alberta's interests on several natural gas and oil pipeline industry task force committees. Energy monitored natural gas and oil pipeline regulatory processes at the U.S. federal and state levels, where there is control and impact on the marketing of Alberta's resources.

The cost of department market access activities in 2015-16 was $7.3 million.

Diversification of Resource Value Chains

Business development activities related to the value-add diversification of resource value chains include the pursuit of commercializing partial upgrading technologies in conjunction with industry. The department and the APMC work collaboratively with other government departments and are actively engaged with industry players to help identify unique challenges preventing an accelerated commercialization path for the technologies.

APMC continues to steward Alberta's interests in the **Sturgeon Refinery** by actively participating in Executive Leadership, Finance, Operations, Health, Safety and Environment, and Commercial Committees. The project is Alberta's newest stand-alone refinery - the first to be built in more than 30 years - and is located approximately 45 kilometres north-east of Edmonton in Sturgeon County. On March 31, 2016, the $8.5 billion, Sturgeon Refinery was approximately 75 per cent complete overall including engineering, procurement and construction and is on track to achieve commercial operations in the fourth quarter of 2017.

The refinery will provide an important new market for Alberta's growing bitumen production. It will remove about 79,000 bbl/d of diluted bitumen from Alberta's export crude oil pipeline system and will add value to it here at home for sales into local, regional, and international markets. The refinery will convert raw bitumen directly into high value ultra-low sulphur diesel and diluents while capturing about two-thirds of the carbon dioxide arising from this processing for sequestration. This maximizes the value for all Albertans by generating higher margins on raw materials while making low carbon dioxide, environmentally responsible products that the market needs.

APMC's roles include 75 per cent feedstock supplier and toll payer and 50 per cent subordinated debt lender. APMC lent an additional $112.5 million in 2015 and a further $99 million in 2016, for a total of $324 million, to the North West Redwater Partnership in the form of a term loan. APMC has entered into long-term agreements for the Sturgeon Refinery to process bitumen into refined products in order to capture additional value within Alberta. There is risk to the APMC under these agreements pertaining to the price differential between the bitumen supplied as feedstock and the marketed refined products, relative to the costs of the processing toll.

The **Petrochemicals Diversification Program** will encourage companies to invest in the development of new Alberta petrochemical facilities by providing up to $500 million in incentives through royalty credits. The Program, announced on February 1, 2016, is part of the government's continued action on the economy, helping to create jobs, attract investment and diversify Alberta's economy. Applications were received in the first quarter of 2016-17 and the Minister of Energy will decide on application approvals in the summer of 2016. Building on Alberta's large supply of methane and propane, the program will capitalize on the growing global demand for related higher value products and promote greater energy-resources processing in Alberta.

The **Incremental Ethane Extraction Program** (IEEP) is a $350 million program established in 2007 that encourages increased petrochemical production in Alberta by providing incentives through royalty credits to offset the high capital costs of recovering incremental barrels of ethane feedstock. IEEP incents ethane extraction for both natural gas sourced ethane, as well as refinery and bitumen upgrading off-gas sources.

During 2015, Energy received ten IEEP applications from approved projects for earned royalty credits, reporting a total of 33,218 bbl/d of eligible ethane produced and requesting a total of about $25 million in royalty credits. About 70 per cent of this ethane is from natural gas sourced ethane with the remaining 30 per cent obtained from off-gas sources.

The IEEP benefited Albertans by helping to sustain the petrochemical sector in the province, which requires abundant, low cost ethane feedstock to manufacture ethylene. The petrochemical sector is supportive of IEEP because it incented capital investment in extraction infrastructure that provides a sufficient volume of ethane from traditional sources such as natural gas processing plants and alternate sources such as upgrader off-gases to support the existing petrochemical base.

Other Achievements:

Industry Investment

Industry investment has been vital to the economic performance of the province and was identified as a key objective of the Royalty Review.

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 with declining crude oil prices, which have affected both Alberta and its competitors.

Upstream oil and gas investment in Alberta consists of conventional oil and gas investment, and oil sands investment. In 2013, a total of $51.6 billion was invested in Alberta's upstream oil and gas industry; in 2014 industry investment increased by 13 per cent, to $58.1 billion. Despite the major decline in oil prices that took place towards the end of the year, 2014 was still the record year for total upstream oil and gas investment in Alberta.

In 2015, the average annual West Texas Intermediate price was US$48.80 per barrel (bbl), which was about 48 per cent lower than the average annual 2014 price of US$ 93.00/bbl. The decline in oil prices has translated into lower investment. Total upstream oil and gas investment for 2015 was projected to decline by Cdn$21.8 billion to Cdn$36.3 billion, or by about 37 per cent relative to the 2014 level. From 2014 to 2015, conventional oil and gas portion of the total upstream oil and gas investment was projected to decline by 38 per cent, from Cdn$22.4 billion to Cdn$13.8 billion; oil sands investment was projected to decline by 37 per cent from the all-time record of Cdn$35.7 billion to Cdn$22.5 billion. The recovery of investment will, to a significant extent, depend on the price environment.

Enhancing Royalty Administration

In 2015-16, a **new requirement was introduced for oil sands project royalties**. Effective June 1, 2015, industry was required to submit unbiased reserves' reports to support the production forecast submitted with their application. The new requirement provides Energy with more certainty that economically viable oil sands projects are approved for the Oil Sands Royalty Program. More confidence in production forecasts benefits Albertans as it helps ensure that the economic criteria are properly assessed and assists in improved royalty revenue projections.

Changes to **Cost Analysis and Reporting Enhancement** (CARE) reports improved oil sands supplemental reporting in 2015-16 by reflecting Energy's current needs for benchmarking analysis. CARE reports are mandatory for oil sands royalty project holders and provide Energy with relevant and accurate oil sands project data to inform important oil sands policy decisions. The new CARE report submission process includes automated data validation checks to ensure that the data submitted by industry is valid and reasonable. Provision of up-to-date and relevant oil sands project data on which to base policy decisions benefits Albertans by ensuring that Alberta's oil sands resource is managed effectively. The new CARE report submission templates are posted on Energy's website for industry to use starting April 1, 2016.

New conventional oil forecasting resources were introduced to PETRINEX, Canada's petroleum information network, to help producers improve their forecasting of Alberta Crown royalty volumes on a monthly basis. Improvement of the Crown royalty share will also enhance forecasting of non-Crown volumes. After over a year of industry consultation, development of an oil forecasting tool on PETRINEX was recommended and will be adopted as a standard across industry. The Oil Forecast Report was implemented in February 2016 and the Oil Forecast Tool is scheduled to be implemented in October 2016-17. The project cost is being funded jointly by the APMC and industry.

Performance Measures

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

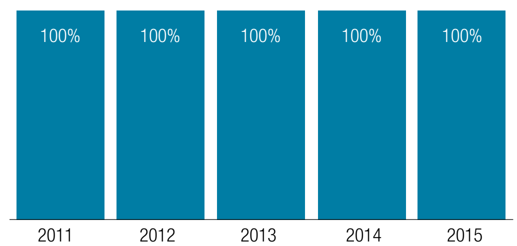
Target

100 per cent of amounts owed are collected.

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.

Figure 1.a
Revenues from oil, oil sands, gas and land sale bonuses are fully collected (Percentage of amounts collected compared to amounts owed)



Sources: Department of Energy.
Note: excludes disputed amounts

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.

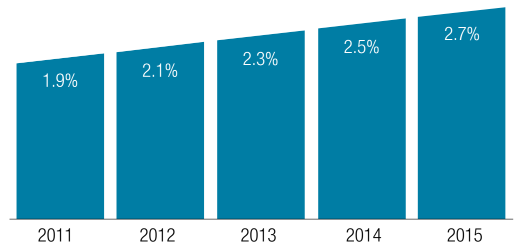
During the year, all amounts have been or are in the process of being collected, and no write-offs have been made. In 2015 and for this annual report, the revenue collection measure result was 100 per cent, the same as the previous four annual reports.

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

Target

2.5 per cent of global oil consumption is supplied by Alberta's oil sands.

Figure 1.b
Alberta's oil sands supply share of global oil consumption



Source: Alberta Energy Regulator ST-39 and ST-53 Reports; International Energy Agency; Oil Market Report.

Discussion of Results

Alberta's oil sands supply share of global oil consumption increased over the examined period, from 1.9 per cent in 2011 to 2.7 per cent in 2015. The target for 2015, which was reported in the 2015-18 Business Plan, was 2.5 per cent. The actual result for 2015 exceeded the target by about 0.2 per cent as oil sands production in Alberta went up at a significantly faster pace than the increase in global consumption.

The oil sands industry in Alberta has been significantly affected by the decline in the oil prices that began in late 2014. In September 2014, the West Texas Intermediate (WTI) Price was US$93.03 per barrel (bbl) and dropped to US$59.29/bbl in December 2014. During 2015, the monthly average WTI price never exceeded US$60.00/bbl, and only peaked at US$59.83/bbl in June 2015. By the end of 2015, the average monthly WTI prices experienced a further decline, reaching the low of US$37.33/bbl.

Despite significant challenges that the industry has been facing due to the oil price decline, Alberta's oil sands production and its share of global consumption still experienced an increase from 2014 to 2015. This increase in Alberta's total oil sands production was due to the start-up of projects under construction that were sanctioned prior to the decline in oil prices.

Over the past several years, oil sands production was consistently increasing. From 2012 to 2013, oil sands production increased by nine per cent, from about 1.9 million barrels per day (bbl/d) in 2011 to about 2.1 million bbl/d in 2012. Alberta oil sands production further increased to about 2.3 million bbl/d in 2013, a 10 per cent increase compared to 2012. In 2015, oil sands production reached an all-time record at 2.7 million bbl/d, which is a 10 per cent increase from the 2014 level.

Notably, global consumption from 2014 to 2015 increased by 1.9 per cent, which is the largest increase in global consumption since the 3.5 per cent increase experienced from 2009 to 2010. However, as the Alberta oil sands production increased at a much faster pace, Alberta's share of global consumption still experienced an increase. Global consumption increased by 1.3 per cent from 2012 to 2013 and 1.0 per cent from 2013 to 2014. The combination of higher Alberta production growth and lower global consumption growth were pushing Alberta's share up during the examined period.

There are several levers available to the Government of Alberta, which indirectly impact the results of the measure. The fiscal and royalty regimes 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, other government policies such as promotion of market access, intergovernmental relations, energy research and development, and environmental regulations influence industry performance and, therefore, oil sands production levels.

DESIRED OUTCOME 2

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

What this means:

The ministry regulates Alberta's energy industry to ensure the efficient, safe, orderly and environmentally responsible development and sustainable management of energy and mineral resources. An integrated, big-picture approach to responsible resource development in the province enables strategic and integrated policies and plans that consider the overall environmental, economic and social outcomes of sustainable energy and mineral development for the benefit of Albertans. The ministry further supports the interests of Albertans by ensuring that the delivery and regulation of Alberta's utility service are fair and responsible.

Priority Initiatives to achieve this desired outcome included:

2.1 Promote sustainable and responsible resource development and environmental stewardship as part of a strategic and integrated system of policies and plans to achieve the balance of social, economic and environmental outcomes that Albertans expect. Collaborate with other ministries to continue to develop and implement:

- *Alberta's Climate Change Strategy* to establish Alberta as an environmentally responsible energy producer and collaborative partner in overall Canadian efforts to reduce emissions;
- enhanced regulation and oversight of the provinces' resources to ensure responsible development; and
- policies to manage the cumulative effects of resource development.

2.2 Develop an integrated *Alberta's Energy Sustainability Strategy* that contributes to economic growth and prosperity and embodies a high standard of environmental and social responsibility for Albertans.

Key Achievements:

Leadership on Climate Change

Energy worked closely with Alberta's Climate Change Office to support the Climate Change Advisory Panel in the development and implementation of the Climate Leadership Plan. The department provided policy advice, economic analysis, strategic support and coordination of key stakeholder and public engagement sessions to help inform the Climate Leadership Plan.

On November 22, 2015, Premier Notley announced Alberta's Climate Leadership Plan. The plan describes four areas of focus for reducing emissions including:

- carbon pricing;
- phasing out emissions from coal-fired electricity generation and enabling the increased development and use of renewable energy in Alberta by 2030;

- a limit on oil sands emissions; and
- reducing methane emissions from the oil and gas sector.

In January 2016, the **Coal Secretariat** was created to provide administrative and analytical support to the Coal Phase-out Facilitator. The Coal Secretariat and the Coal Phase-out Facilitator will lead engagement with coal-generation companies to achieve the government's climate change policy objective of phasing out emissions from coal-fired generation by 2030. A successful achievement of the policy objective will maintain the reliability of Alberta's electricity grid, maintain reasonable stability of prices for consumers, and avoid unnecessarily stranding capital of companies. The Coal Phase-out Facilitator began work in April 2016.

The work of this team is critical to the rest of the Climate Leadership Plan initiatives that relate to electricity as it will create confidence among investors and companies to invest in new generation in the province so that Albertans will continue to have their electricity needs met. The outcome of this engagement will support a suite of policies, including the reduction of coal-fired generation and the launch of the **Renewable Electricity Program** that will ultimately reduce emissions related to electricity generation. The department and the Alberta Electric System Operator have jointly established and begun implementation on a 2030 plan for renewable energy.

Total greenhouse gas **emissions from all oil sands** facilities has been limited to 100 megatonnes per year. In early 2016, work began to legislate this limit and to develop policies and regulations to operationalize the limit effectively. This will be done in consultation with industry, Indigenous groups and other interested stakeholders. The work is being led by the Alberta Climate Change Office with support from Energy.

The goal for methane is a 45 per cent reduction in the oil and gas sector from 2014 levels by 2025. Energy has been tasked with **leading methane reductions** from the oil and gas sector. Working with Alberta's Climate Change Office and the Alberta Energy Regulator, a five-year multi-stakeholder process will work towards achieving reductions from existing oil and gas facilities. The Government of Alberta will concurrently develop regulation for oil and gas operations including: measurement and reporting, leak detection and repair and new facility standards.

The department has begun consultation with energy stakeholders in support of the work being done by the Alberta Climate Change Office and Treasury Board and Finance to implement the **carbon levy** on fuel combustion.

An Integrated Approach to Resource Management

Energy continued to collaborate with partner departments and agencies involved in responsible resource development. The integrated approach enables government to speak to Albertans with one voice; to hear multiple viewpoints and to make decisions based on the best available information.

A framework for measuring and reporting on ongoing performance was adopted for the Regulatory Enhancement Project and the Integrated Resource Management System; measuring and reporting will commence in 2016. With the adoption of performance measures for the Regulatory Enhancement Project, the sixth and final deliverable of the Regulatory Enhancement Project was completed.

In November 2015, the Policy Management Office merged with Environment and Parks' Integrated Resource Management System Office to form the Integrated Resource Management System Secretariat. The Secretariat's functions include: policy integration, oversight of Alberta Energy Regulator rules development, and performance measurement.

Excellence in Energy Regulation

In 2014, the Alberta Energy Regulator (AER) launched a project to help identify the key attributes of an excellent regulator. In April 2016, the AER completed the **Regulatory Excellence project**. This laid the foundation for AER to create a model for regulatory excellence specific to energy regulation in Alberta and to measure its performance in how its internal management enables effective and efficient regulatory actions that deliver outcomes for Alberta.

The key areas of work that support the AER's vision of being recognized for Regulatory Excellence include:

- regulatory approaches that holistically consider regional, geological and environmental conditions, operator performance, and the values, concerns and knowledge of Albertans, Indigenous peoples and stakeholders. Strategic planning that is focused on measurable outcomes to gauge how the AER's regulatory actions contribute to the social, economic and environmental fabric of Alberta;
- setting up a Centre of Regulatory Excellence to ensure AER employees have the skills, knowledge and competencies required in their roles; and
- a cultural blueprint that articulates the desired behaviours that support the AER's values.

The total cost for the work of the AER in 2015-16 was $280 million and was fully funded by industry.

Excellence in Regulation of Public Utility Services

In 2015, the **Alberta Utilities Commission (AUC) celebrated 100 years of public utility regulation** in Alberta with the core responsibilities of regulating the price, service quality and supply of public utility services since 1915.

The AUC initiated a generic proceeding to establish parameters for the next generation of **performance-based regulation** (PBR) plans. PBR is a regulatory tool to incent distribution utility companies to be more efficient so that ratepayers can benefit through lower rates over time when compared to a traditional cost-of-service model, while still safeguarding system reliability and service quality. A decision on the generic proceeding is expected in the fall of 2016, at which point the Commission will initiate a process for the filing of applications for implementing the newly established next generation PBR framework.

The AUC introduced its **enforcement program** that promotes compliance with relevant law, AUC rules, decisions and orders. The primary goal of enforcement is to promote compliance with Alberta utility laws and to prevent harm to any person, public or private property or to the integrity of the AUC's regulatory processes and to ensure that the public and regulated entities understand that there are serious consequences for contraventions. The program included the Commission's enforcement policy including the investigation and enforcement stages as well as some aspects of enforcement proceedings commenced by the Market Surveillance Administrator. Persons subject to the regulatory requirements of the Commission are responsible for implementing policies and programs to prevent contraventions, and for taking steps to mitigate them if they occur.

The AUC pioneered Canadian utility regulation in its review of the **Market Surveillance Administrator (MSA)-TransAlta enforcement proceeding** as it was the first of its type and magnitude to be heard before the AUC for adjudication. The AUC found that TransAlta contravened Alberta's *Fair, Efficient and Open Competition Regulation and Electric Utilities Act*. Specifically, TransAlta restricted or prevented its competitors from providing a competitive response, it manipulated market prices away from a competitive market outcome for its own benefit, and it allowed energy trading based on insider information to occur. The AUC approved a settlement under which TransAlta Corporation will pay $56 million to resolve its contraventions, which includes an administrative penalty, as well as covering the full costs of the MSA's investigation and the MSA's participation in the AUC proceeding.

As a trusted leader that delivers innovative and efficient regulatory solutions for Alberta, the AUC is committed to **reviewing its regulatory processes** to identify opportunities to reduce unnecessary regulatory burden and lower costs for consumers. The AUC continued to make more relevant and effective regulation through the following initiatives:

- Changes to ***AUC Rule 007*** applies to applications for the construction or alteration and operation of power plants, substations, transmission lines, and industrial system designations and includes:
  - amendments to clarify and streamline information requirements for needs identification documents, and abbreviated needs information documents will result in an effective review of the need, without any loss of AUC oversight or opportunity for landowner input at the facility siting stage;
  - amendments to clarify environmental information requirements for transmission and power plant facility applications should clarify the requirements for applicants and ensure the effective and efficient review of facility applications by the AUC and Environment and Parks; and
  - application exemptions for certain types of isolated generating units which align with previous exemptions for power plants with a capability of less than 10 megawatts that produce power solely for the owner's use.
- Amendments to the **minimum filing requirements** for applications to share records pursuant to Section 3 of the Fair, Efficient and Open Competition Regulation. These amendments address deficiencies in previous applications where the Commission has lacked the information necessary to expeditiously consider applications which has necessitated information requests or other procedural delays.
- The AUC facilitated consultations with electricity industry stakeholders and **Measurement Canada** to determine if the practice in Alberta for calculating electricity consumption was consistent with all regulatory requirements. Gaps were identified, which required investment in new meters with the cost to be borne by ratepayers. The AUC worked with stakeholders to establish an alternative calculation method which was accepted resulting in savings to ratepayers.

The total cost for the work of the AUC in 2015-16 was $33 million and was fully funded by industry.

Managing the Cumulative Effects of Resource Management

Work continued on **land and access policy** issues to ensure Albertans benefit from responsible energy and mineral development. This includes work led by the department around access to resources as well as supporting other ministries that have linkages to energy development.

Municipal issues supported by Energy included the *Municipal Government Act* Review and Big City Charter discussions with the cities of Edmonton and Calgary, as well as other municipal-related policy matters that have implications for energy development.

A review of **liabilities related to energy development** commenced and a plan for the review was developed to address any gaps, reduce and proactively manage historic, current and future liabilities over the long term. The Alberta Energy Regulator and Environment and Parks are supporting this work.

The **Lower Athabasca Regional Plan** (LARP), the first of seven regional plans across the province, came into force on September 1, 2012 and provides strategic direction to balance long-term opportunities for oil sands development with important environmental and social considerations. Implementation of key environmental strategies under LARP is continuing, as well as the establishment of new conservation areas and provincial recreation areas.

All agreements cancelled as a result of conservation areas established through the LARP have been compensated. The total compensation paid to the lease holders as of March 31, 2015 was almost $34 million.

The **South Saskatchewan Regional Plan** (SSRP) came into effect on September 1, 2014, following consultation and engagement with Albertans. The SSRP addresses key issues and provides strategic direction to facilitate the establishment of new conservation areas for the protection of headwaters and water security, species-at-risk management, and management of recreation, in order to balance environmental and social values with development. Energy continues to work with other ministries to advance implementation of the SSRP.

The Government of Alberta initiated the process to enhance the protection of the Castle area, which is within the South Saskatchewan Region. The final decision relating to this is expected in summer, 2016.

Background preparation work continued for the **Upper and Lower Peace Regional Plans**. The department provided analysis of energy and mineral resources and issues in these regions to the Land Use Secretariat, which leads Cross-Ministry Planning teams' efforts to support and provide policy guidance for the development and implementation of regional plans under the government's Land-use Framework.

Energy is leading work to enhance risk mitigation in relation to **induced seismicity** in the province. Induced seismicity refers to earthquakes resulting from human activities. Energy authored a White Paper on induced seismicity in January 2015, and shortly thereafter convened the Induced Seismicity Working Group to lead work on assessment of current mitigation and risk management tools. The department continues to work with provincial, national, and international partners to advance knowledge around induced seismicity and effect targeted enhancements to manage risk.

Energy advanced work to promote responsible development of energy resources contained in the **Duvernay and Montney formations**. Working with partner ministries and agencies, Energy engaged with various stakeholders and tested the interest in a pilot project to better manage cumulative effects in the Fox Creek area. The Government of Alberta solicited input from various First Nations communities, Métis groups, oil and gas and forestry industry associations and groups, as well as several other stakeholders in identifying key policy areas, species, and other challenges in the area.

In 2015-16, work continued on the implementation of the Athabasca Oil Sands Area and the Cold Lake Oil Sands Area **Comprehensive Regional Infrastructure Sustainability Plans** (CRISPs). The CRISPs facilitate sustained prosperity and a quality of life that attracts and retains individuals, families and business in the province's oil sands. In the Athabasca Oil Sands Area, twinning of Highway 63, south of Fort McMurray, was mostly completed. A major interchange was opened in Fort McMurray providing access to the Parson's Creek residential community. Regional planning related to transportation priorities and aviation infrastructure was also undertaken. In Cold Lake, options were identified in regards to transportation, the development of high load corridors to facilitate industry access in the region.

The **Urban Development Sub-Region** (UDSR) policy was developed to provide land to Fort McMurray to address their growth needs spurred by the rapid development of resources in the region. In support of this policy, Energy proceeded to cancel the affected oil sands agreements, or portions thereof, to ensure there would not be future land-use and resource development conflicts. The land will now be sold to the Regional Municipality of Wood Buffalo (Fort McMurray) through the normal Crown land sales process. In total, Energy cancelled 40 oil sands agreements in 2014-15 and 2015-16, with total compensation of $65.7 million paid to affected leaseholders. Cancellation of all oil sands agreements within the UDSR area was completed this year.

A Long-Term Strategy for Energy Development in Alberta

Alberta is blessed with abundant energy resources that play an essential role in the living standards and prosperity of Albertans. Alberta's energy endowment has allowed for growing prosperity, propelling the national economy forward. Government must build on our success with the continued development of our energy resources in ways that are integrated and environmentally sound.

Energy initiated a cross-ministry process to develop a long-term energy strategy for the province that contributes to economic growth and prosperity, and embodies a high standard of environmental and social responsibility. This work will further integrate recommendations of the climate change review and royalty review panel. This energy strategy will position Alberta as a trusted and reliable energy supplier that is open to investment.

Other Achievements:

Leadership in Systemic Design

Systemic design is an emerging practice for addressing complex policy challenges. The Department of Energy's cross-ministry systemic design team, CoLab, has been recognized nationally and internationally. In 2015, CoLab hosted the Relating Systems Thinking and Design Symposium in Banff. This was the first time the major international conference in this field had been held in North America. CoLab was also featured in the January 2016 issue of Canadian Government Executive Magazine.

In 2015, 33 projects across the Government of Alberta utilized Energy's Systemic Design team on projects ranging from energy strategy to economic diversification to taking a whole government approach to international engagement. In the past year, CoLab has also provided interactive training in systems thinking and design for over 1,000 civil servants. While CoLab has a cross-government mandate, the majority of its projects are focused on energy and the integrated resource management system.

Integrated, Consistent Credible Data Supporting Responsible Resource Development

The **Crown Land and Mineral Rights Assurance** (CLMRA) initiative originated with the Surface-Subsurface Review, led by Energy from 2009 to 2011. The long-term objectives for this initiative are that organizations participating in surface reservation and subsurface restriction decisions do so in an integrated manner across all affected parties and that data supporting these decisions be integrated, consistent and credible across all parties.

Decisions regarding the availability of Crown mineral rights for sale are directly informed by legislation and policy applied by Energy, Environment and Parks, Agriculture and Forestry, Indigenous Relations, Culture and Tourism, and Municipal Affairs, Transportation, Infrastructure, as well as by the Alberta Energy Regulator.

In 2015-16, Energy moved this work forward by developing a Terms of Reference and a detailed Conceptual Model. Current and proposed business process and data governance were documented and a baseline analysis of existing internal mineral restrictions were completed. Energy is working with Environment and Parks, to ensure alignment between surface reservations and subsurface restrictions, and with the Land Use Secretariat, to implement the governance processes.

Enhancing the minerals geoscience knowledge base for Alberta is needed for responsible mineral development and to support Alberta's vision of economic diversification. Easily accessible information about Alberta's metallic and industrial mineral resources is essential for responsible resource management and to attract investment interest in Alberta. Raising the profile of Alberta's metallic and industrial mineral opportunities encourages economic diversification through mineral exploration and development, particularly in remote communities.

The intention of increasing minerals geoscience capacity is to lower the costs and reduce risks to companies looking to invest in Alberta. As well, the work enhances the ability to quickly compile mineral information for resource development policy, such as land-use planning.

In 2015-16, Energy worked with the Alberta Geological Survey to support a web-based map and data dissemination tool called the Alberta Interactive Minerals Map. The map provides information to users about Alberta's metallic and industrial mineral occurrences and raises awareness of Alberta's mineral potential.

In addition to the $75,000 grant Energy provided to the Alberta Interactive Minerals Map in 2014-15, Energy provided another $75,000 to continue the population of data and information to the Map. The interactive map has received over 12,800 visits since it's launch in June 2015.

In May 2015, Alberta Energy launched a new **Alberta Mineral Assessment Report System** (ABMARS). Metallic and Industrial Mineral Assessment Reports are the record of mineral exploration work in Alberta and are a significant collection of geological information that is used by domestic, national, and the global communities including investors and mineral explorers, to make investments. ABMARS provides the following functions:

- an administrative function that facilitates Energy's review of mineral assessment reports and,
- a public mineral assessment report database.

The public database builds on the progress previously made to scan all assessment reports and make them available worldwide online. The current database contains over 1000 reports from as early as 1949 and is regularly updated. This year Energy launched a search function to allow users to search mineral assessment report metadata and the full text of each report. The ABMARS search page can be found on Energy's website at **energy.alberta**.

Performance Measures

Performance Measure 2.a: Regulatory compliance (AER)

Target

Greater than or equal to 97 percent of inspections are in compliance with regulatory requirements.

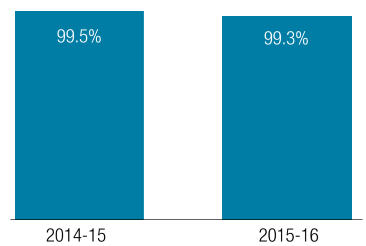
Discussion of Results

This performance measure indicates industry's compliance with regulatory requirements. Regulatory compliance is achieved when the outcome of inspection does not result in an enforcement action against the licensee. An enforcement action can occur when the licensee fails to address a contravention of rule(s)/regulation(s)/requirement(s), and/or has caused a significant impact to public safety, the environment, or resource conservation.

Enforcement action is defined as an exercise of statutory power of the regulator in response to a finding of noncompliance including:

- warning letters;
- administrative penalties;
- orders;
- prosecutions;
- imposing of terms and conditions;
- shutting down of operations; and
- suspension or cancellation of a license approval, permit or reclamation certificate.

Figure 2.a
Regulatory compliance (Percentage of inspections that are in compliance with regulatory requirements)



Source: Field Surveillance Inspection System database

*The results for 2014 have been restated from calendar year to fiscal year. The results reflect data availability from July 1, 2014 when the transition to the new Compliance Assurance Framework began. The targets for 2015-16 and forward are based on fiscal year which aligns with AER's reporting periods.

In 2015, the results exceeded the target of 97 per cent by 2.3 per cent. The Alberta Energy Regulator (AER) conducted 11,228 initial inspections, which resulted in the issuance of 83 non-compliances that were comprised of 68 suspensions, seven warning letters, five administrative penalties, and three orders. The 2015-16 results are within the expected range of compliance. Results cannot be compared to 2014 because the transition to the new Compliance Assurance Framework began on July 1, 2014 and therefore data was only available for the last nine months of 2014-15.

The results demonstrate progress toward the desired outcome of ensuring industry compliance with regulatory requirements.

Year	Number of inspections resulting in a finding of compliance	Total number of inspections	Percentage of inspections resulting in a finding of compliance
2015-16	11,145	11,228	99.3%
2014-15*	9,890	9,935	99.5%

*The results for 2014 have been restated from calendar year to fiscal year. The results reflect data availability from July 1st, 2014 when the transition to the new Compliance Assurance Framework began. The targets for 2015-16 and forward are based on fiscal year which aligns with AER's reporting periods.

A significant achievement in 2015 was the release of the *Integrated Compliance Assurance Framework* and *Manual 013: Compliance Assurance Program*, both of which reflect AER's broader mandate and responsibilities under the *Responsible Energy Development Act*. The *Integrated Compliance Assurance Framework* establishes and standardizes the AER's approach to compliance assurance activities for regulatory responsibilities under the *Public Lands Act*, the *Water Act*, the *Environmental Protection and Enhancement Act*, and the responsibilities of its predecessor organization, the Energy Resources Conservation Board. Standardization of the compliance assurance process across the organization results in a consistent approach to the application of enforcement actions.

Other activities contributing to the high percentage of inspections being in compliance with regulatory requirements include:

- an increased focus on field staff training in 2015-16 resulting in better understanding, identification, and application of the compliance assurance program;
- meetings with companies that have historically had poor performance;
- reducing the leading cause of incidents, including detailed analysis of the leading causes and targeted industry education programs; and
- improving regulatory controls by eliminating duplicative, outdated, and redundant requirements

Inspections are selected based on a predetermined level of risk that the activity may pose to health and safety, the environment, resource conservation and stakeholder confidence in the regulatory process. Transparency in the compliance assurance process is demonstrated on the external compliance dashboard that displays AER's involvement in incident response, investigations, and compliance and enforcement activities. Additionally, the AER publishes education material and educates industry by way of informal presentations and operator awareness sessions to increase awareness of directives, rules and regulations.

Performance Measure 2.b: Timeliness of the needs and facility applications (AUC)

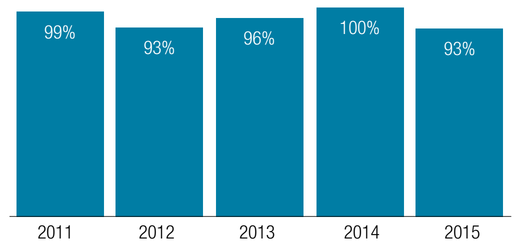
Target

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

Discussion of Results

In accordance with standards established in Alberta law, 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, the Alberta Utilities Commission (AUC) must make a decision in a timely manner, and if possible, within 180 days after receipt of a complete application.

Figure 2.b
Timeliness of the needs and facility applications
(Percentage of needs and facility application)



Source: Alberta Utilities Commission

The target for timeliness of needs and facility applications is 100 per cent. In 2015, the result was 93 per cent. There were 40 out of 43 decisions that were issued within the 180 day timeline. The decisions that missed the 180-day deadline were delayed by procedural matters: one hearing was deferred at the request of interveners, one was deferred at the request of the applicant and another due to an unexpected question of constitutional law raised during final argument.

DESIRED OUTCOME 3

Albertans benefit from safe and reliable energy-related infrastructure and innovative energy technologies

What this means:

Reliable, efficient and resilient energy systems are vital to the social and economic foundation of Alberta. To meet the increasing demand for electricity and to access new markets, energy-related infrastructure is needed. In the interest of Albertans, the ministry develops effective innovation policies and programs and works with other ministries and stakeholders to support energy infrastructure development, innovative technologies and energy and mineral resources processing improvements.

Priority Initiatives to achieve this desired outcome included:

3.1 Develop, review and implement policies and regulations to ensure a safe, reliable, efficient, affordable and environmentally responsible electricity system for Albertans by:

- supporting the electricity and natural gas needs of Albertans; and
- enabling the increased development and use of alternative and renewable energy in Alberta.

Key Achievements:

Improved Regulation of Electricity and Natural Gas Retail Markets

The new Code of Conduct Regulation for the electricity and natural gas retail markets came into effect on January 1, 2016 resulting in a new Alberta Utilities Commission (AUC) *Rule 030: Compliance with the Code of Conduct Regulation*. This new regulation consolidated and modified the provisions that were previously contained in the separate code of conduct regulations. The duties that were previously performed by the Market Surveillance Administration, i.e., oversight of owners of electric distribution systems and their affiliated retailers have become the responsibility of the AUC. These duties include reviewing and approving the compliance plans, variance requests, reporting and conducting compliance audits.

The harmonized regulation controls a range of activities by regulated monopoly utilities and associated competitive retailers. The regulation is intended to help protect consumers from unfair market conduct and ensure a level playing field between independent retailers and retailers associated with regulated utilities.

As of January 1, 2016, the Billing Regulation and the Regulated Rate Option Regulation require electricity bills to display the consumer’s municipality next to the Local Access Fee line item. This fee is collected by electric utilities on behalf of local governments. In exchange for these fees, utilities are granted access to municipal land to construct, maintain and operate the electric distribution systems. These changes to the regulation improve transparency.

Transmission Cost Management

In 2015-16, the AUC concluded its examination of the cost oversight management function on a pilot basis to assess its effectiveness. The cost oversight management function is a new regulatory approach to electricity transmission cost review and seeks to provide proactive, third-party expert review and comment on transmission project costs at earlier, specific stages of a transmission project from planning through construction completion. The current regulatory process is largely an after-the-fact review of costs after the project has been constructed. The consultants engaged to undertake the pilot completed transmission project review reports and a final report summarizing its overall findings.

Alternative and Renewable Energy

In Alberta, alternatives are defined as energy sources such as natural gas cogeneration that are more efficient for the production of electricity than traditional energy sources like coal and natural gas. Renewable energy is defined as energy sources that can be naturally regenerated within a human lifespan and in Alberta they include wind, solar, hydroelectricity, geothermal, biogas, and biomass. Through its policy framework, the Government of Alberta supports the development of alternative and renewable energy in the province.

Over the past five years, alternative and renewable generating capacity has grown steadily with a 24 per cent increase from 2011 to 2015. This was largely driven by growth in both wind and gas cogeneration. Alberta's policy framework has created a stable environment to encourage growth in alternative and renewable technologies.

Alternative and Renewable Generating Capacity (Megawatts)	2011	2012	2013	2014	2015
Wind	895	1,113	1,113	1,459	**1,491**
Hydro	900	900	900	900	**902**
Biomass	359	414	417	438	**424**
Gas Cogeneration	3,651	4,051	4,160	4,165	**4,372**
Total	**5,805**	**6,478**	**6,590**	**6,962**	**7,189**

The **Bioenergy** Producer Credit Program was a five year program that supported the production of energy products from biomass. The program ended on March 31, 2016. In 2015-16, a total of $69.8 million was paid to 25 grant recipients under the Bioenergy Producer Credit Program. This reflects payments made in support of production for the first three quarters of 2015-16 and the accrual amount for the fourth quarter, as payment have not yet been determined.

Other Achievements:

Decline in Pipeline Incidents

Pipelines transport most of the natural gas, crude bitumen and crude oil produced in Alberta to processing facilities and eventually to market. A pipeline incident is defined as a hit, leak or rupture. In 2015, the rate of pipeline incidents declined to 1.2 incidents per thousand kilometres (km) of regulated pipeline in 2015 from 1.6 incidents per thousand km of regulated pipeline in 2014. The decline in pipeline incidents occurred for both high and low impact incidents.

The AER uses a risk-based approach to regulating pipelines in order to more efficiently and effectively focus their resources. The potential impacts of incidents are categorized by the AER according to the incident response priority level. A pipeline incident receives a higher response priority level based on the hydrogen sulphide concentration, environment, public, wildlife and/or area affected and/or the substance release type and volume. A high impact pipeline incident represents a more significant impact to the public or environment and is defined as a response priority 1 or 2 release.

Year	Priority 1	Priority 2	Priority 3	Total	Length (km)	Incidents per 1,000 km
2014	55	89	549	693	427,998	1.6
2015	38	63	403	504	431,448	1.2

The AER regulates over 431,448 km of pipeline in Alberta. Programs initiated by the AER have resulted in greater industry awareness and engagement in preventing incidents. Industry education activities and an increased focus on higher-risk situations has resulted in more shared learnings and improved performance. Improved reporting tools enable fact based interactions with industry leading to effective changes in behavior.

The AER is currently working on a plan to assess the threats, risks and impacts to the Industrial Control Systems used in provincially regulated oil and gas pipelines. This work is part of broader AER efforts to ensure Alberta's pipeline systems are safe and reliable.

Innovative Energy Technologies Program

The Innovative Energy Technologies Program is a $200 million commitment by the Government of Alberta which supports innovation, research and technology development. The program provides royalty adjustments to support first-of-a-kind applied research pilot projects that use innovative technologies to further the production of oil, oil sands (mining and in-situ) and natural gas.

In 2015-16 there were five active projects, one of which is in the process of being completed, and paid $4.5 million in royalty adjustments.

Carbon Capture and Storage

In 2015-16, milestones were reached for the Quest carbon capture and storage project, specifically Quest reached commercial operations stage and celebrated the official project launch in the fall. Quest is one of a handful of carbon sequestration projects to reach this stage internationally and the first application of this technology in the oil sands industry. The Quest project is expected to store over one million tonnes of carbon dioxide each year. This is roughly equivalent to the annual emissions of 250,000 cars. Quest is expected to be in operation for the next 25 years.

Throughout the year, the department continued to monitor, administer and ensure compliance under the carbon capture and storage funding agreements for the Alberta Carbon Trunk Line and Quest projects. As of March 31, 2016, a total of $461.4 million has been paid to the projects for achievement of milestones.

DESIRED OUTCOME 3

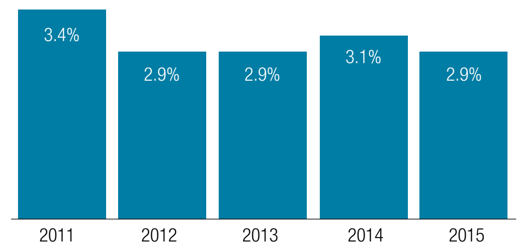
Performance Measures

Performance Measure 3.a: Transmission losses

Target

To maintain a minimum level in transmission losses. The target for 2015-16 was 3.0 plus or minus 0.3 per cent.

Figure 3.a
Transmission losses



Source: Alberta Electric System Operator

Discussion of Results

Electricity is a facilitator of economic development in Alberta. A strong, reliable and efficient 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, generation developers will know that they will be able to efficiently move their product to market. In turn, they will have confidence to develop new generation ensuring an adequate, reliable supply of electricity to Albertans. Until transmission is improved, potential renewable or low-emission electricity generation in Alberta will remain constrained by location. There are hydroelectric resources in the north, wind and solar in the south, and biomass in the northwest. 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.

The transmission line loss of 2.9 per cent for 2015 meets the target of 3.0 ± 0.3 per cent. 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.

Performance Measure 3.b: Power generation

Target

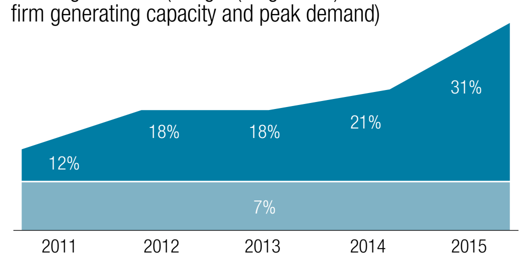
Maintain a minimum seven per cent margin over peak demand.

Discussion of Results

Alberta's economic prosperity and high standard of living relies on access to reliable and plentiful electricity. The Government of Alberta has created a framework that facilitates a competitive wholesale power market. This framework has resulted, over the long term, in electricity supply keeping pace with Alberta's growing demand for power.

For this measure, the desired outcome is to maintain a minimum seven per cent margin over the annual peak demand. The seven per cent margin is a specific identifiable reliability requirement set by the Western Electricity Coordinating Council, the regional entity responsible for coordinating electric system reliability in several jurisdictions in Canada, the United States and Mexico.

Figure 3.b
Power generation (Margin (megawatts) between firm generating capacity and peak demand)



Sources: Alberta Utilities Commission, Alberta Electric System Operator and Department of Energy.

Notes: Through industry investment, Alberta's net supply margin of electricity will be sufficient to ensure reliable power supply.

[1] Firm Generating Capacity excludes:
- wind power, which is not dispatchable on a consistent basis;
- small hydro, which has minimal storage capability for operation during winter, when peak demand occurs;
- 25 per cent of large hydro, to reflect limitations on its output during winter, when peak demand occurs; and
- tie line capacity, which is not dispatchable on a consistent basis.

Firm electricity generating capacity was calculated at 14,339 megawatts (MW) for 2015. This was a 788 MW (or 5.8 per cent) increase over the 2014 level. The peak demand in the winter period of the climatic year (October 1, 2015 to March 31, 2016) was 10,982 MW. This was 247 MW (or 2.2 per cent) lower than the peak of 11,229 MW set in the winter climatic year (October 1, 2014 to March 31, 2015).

In 2015, the margin between the firm electricity generating capacity and peak demand was 31 per cent. This was a significant achievement as it reaffirms that Alberta's electricity system continues to maintain a healthy level of excess firm generating capacity to meet its highest hourly demand for electricity in the course of the year. This result is an indication that Albertans' electricity needs are being met through a resilient electricity system.

An external factor that contributed toward achieving a higher margin in 2015 was weather. The winter of 2015-2016 was generally a warmer winter and that resulted, other things being equal, in a lower demand for electricity that would otherwise be the case in a colder weather.

On maintaining a reliable and resilient electricity system as measured by the health of the power margin, it is important to note that, unlike most other jurisdictions, the Government of Alberta neither invests in building electricity generation nor financially supports investors to build generation. Alberta defers to market forces and private investors to build generation when needed and also determine the amount of the excess firm generating capacity to meet the highest system demand when it occurs. The generation assets in Alberta are built by private investors who bear all the financial risks, not the electricity consumers or Alberta tax payers. Unless there are significant shifts or directions in government policy that would affect the electricity system in Alberta, the lessons learned in the past two decades since the restructuring of Alberta's electricity market in 1996 suggest that Alberta may continue to rely on market to provide for adequate generation capability for Albertans in a timely manner.

Appendix A: Energy Highlights

Resource		2014-15	2015-16
Bitumen	Revenue	$5.05 billion	$1.22 billion
	Percentage of non-renewable resource revenue	56%	44%
	Bitumen wells drilled (Development)	2,033 (2014)	881 (2015)
	Total bitumen production in barrels per day (bbl/d)	2.30 million bbl/d (2014)	2.53 million bbl/d (2015)
	Marketable bitumen and Synthetic Crude Oil (SCO) production	2.16 million bbl/d (2014)	2.37 million bbl/d (2015)
Conventional Crude Oil	Revenue	$2.25 billion	$0.69 billion
	Percentage of non-renewable resource revenue	25%	25%
	Crude oil wells drilled (Development)	2,528 (2014)	803 (2015)
	Average price for West Texas Intermediate	US$80.48/bbl	US$45.00/bbl
	Crude oil production	0.59 million bbl/d (2014)	0.53 million bbl/d (2015)
	Pentanes and condensate production	0.15 million bbl/d (2014)	0.18 million bbl/d (2015)
Total Crude and Equivalent	Revenue	$7.29 billion	$1.91 billion
	Production (conventional, marketable bitumen and SCO, pentanes and condensates)	2.90 million bbl/d (2014)	3.08 million bbl/d (2015)
	Total crude oil deliveries	3.01 million bbl/d (2014)	3.26 million bbl/d (2015)
	* To the United States	74%	77%
	* Within Alberta	15%	12%
	* To rest of Canada	11%	10%
	* Offshore	0.1%	0.1%
Natural Gas and By-Product	Revenue	$0.99 billion	$0.49 billion
	Percentage of non-renewable resource revenue	11%	18%
	Number of conventional natural gas wells drilled (Development)	1,529 (2014)	983 (2015)
	Average Alberta Reference Price (Gas) per Gigajoule (GJ)	$3.51/GJ	$2.21/GJ
	Total marketable natural gas production including Coalbed Methane in trillion cubic feet (Tcf)	3.6 Tcf (2014)	3.7 Tcf (2015)
	Coalbed Methane production	0.25 Tcf (2014)	0.23Tcf (2015)
	Total natural gas deliveries	4.4 Tcf (2014)	4.5 Tcf (2015)
	* To the United States	34%	34%
	* Within Alberta	35%	36%
	* To rest of Canada	31%	30%

Resource		2014-15	2015-16
Bonuses and Sales of Crown Leases	Revenue from bonuses and sales of crown leases	$0.48 billion	$0.20 billion
	Revenue from rentals and fees	$0.17 billion	$0.17 billion
	Average price per hectare (ha) paid for petroleum and natural gas rights sales	$357.04	$158.64
	Petroleum and natural gas hectares sold	1,277,405 ha	1,284,907 ha
	Average price per hectare paid for oil sands mineral rights	$527.29	$42.30
	Oil sands hectares sold	45,695 ha	39,909 ha
Freehold Mineral Tax	Revenue	$172 million	$79 million
Wells and Licenses	Well Licenses issued	9,345 (2014)	4,646 (2015)
	Industry drilling	4,562 (2014)	5,371 (2015)
Coal	Revenue	$16 million	$14 million
	Established coal reserves (estimate)	33.2 billion tonnes (2014)	33.2 billion tonnes
	Raw coal production	33.8 million tonnes (2014)	30.2 million tonnes (2015)
	Total marketable coal deliveries	31.0 million tonnes (2014)	27.4 million tonnes (2015)
	Percentage of total coal deliveries exported out of province	20% (2014)	15% (2015)
Electricity	Total generation capacity in Megawatts (MW)	15,314 MW (2014)	16,133 MW (2015)
	Total generation capacity from renewable sources	2,797 MW (2014)	2,817 MW (2015)
	Total generation capacity from coal	6,258 MW (2014)	6,267 MW (2015)
Metallic and Industrial Minerals	Revenue	$599,575	$774,577
	Hectares of mineral permits issued to exploration companies	1.7 million ha	1.3 million ha

Note on sources and data usage:

Energy relied on data gathered by the department, as well as the Government of Alberta, Alberta Energy Regulator, Alberta Utilities Commission, International Energy Agency and Statistics Canada to complete the Energy Highlights table. The department applied specific conversion and calculations to select data gathered from external sources and, therefore, results published above may differ from results reported by the sources.

Appendix B: Performance Measure Methodologies

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 Operation (COO) 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.

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 Energy, using the web-based Electronic Transfer System (ETS). OASIS then sends the charge information to the Corporate Accounting Revenue 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 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 sale or 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 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 the 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:

$$\frac{\textit{Annual Barrels of Alberta Oil Sands Production}}{\textit{Barrels of World Oil Consumption}}$$

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

Performance Measure 2.a: Regulatory compliance

The AER established a target of 97 per cent for this measure based on data compiled during the transition to the new compliance assurance framework, which better reflects its new authorities and mandate. The target is the expected percentage of inspections conducted that are in compliance with regulatory requirements.

AER field operations staff inspect the activities of the in-situ and conventional oil and gas, pipeline and coal and oil sands mining industries. Inspections result in an outcome of compliant or noncompliant. The inspection findings and outcome are entered into the Field Surveillance Inspection System database. 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.

Performance Measure 2.b: 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 AUC deems the application complete. The status of applications is tracked daily.

Performance Measure 3.a: Transmission losses

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

$$\textit{Transmission Losses (\%)} = \frac{\textit{Line Losses}}{\textit{Alberta's annual internal load}} \times 100\%$$

Source Documentation: The AESO publishes Alberta's annual internal load each year in its Annual Market Statistics report. The AESO publishes line losses each year in its Annual Report. The AESO calculates line losses as follows:

Line Losses = (Total Generation + Imports) — (Total Consumption + Exports)

Performance Measure 3.b: Power generation

The intent of the measure is to demonstrate that there is sufficient margin between firm electricity generating capacity and peak demand. The margin for the measure is reported as the percentage MW difference between firm generating capacity and peak demand. For this performance measure, all wind and a portion of the hydro capacity, which are not dispatchable on a consistent basis, are excluded from the total installed generating capacity. Peak demand is defined as the highest hourly recorded system demand (in megawatt-hours) in the climatic year (October 1, 2015 through to March 31, 2016) as recorded by the Alberta Electric System Operator.

Financial Information

MINISTRY OF ENERGY

FINANCIAL STATEMENTS
For the year ended March 31, 2016

Independent Auditor's Report

To the Members of the Legislative Assembly

Report on the Consolidated Financial Statements

I have audited the accompanying consolidated financial statements of the Ministry of Energy, which comprise the consolidated statement of financial position as at March 31, 2016, and the consolidated statements of operations, change in net debt and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated 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 consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

My responsibility is to express an opinion on these consolidated financial statements based on my audit. I conducted my audit in accordance with Canadian generally accepted auditing standards. Those standards require that I comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements 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 entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my audit opinion.

Opinion

In my opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Ministry of Energy as at March 31, 2016, and the results of its operations, its changes in net debt and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Original signed by Merwan N. Saher, FCPA, FCA
Auditor General

June 6, 2016

Edmonton, Alberta

MINISTRY OF ENERGY

CONSOLIDATED STATEMENT OF OPERATIONS

Year ended March 31, 2016

(in thousands)

	2016		2015
	Budget	**Actual**	**Actual**
			(Note 19)
Revenues (Schedule 1)			
Non-Renewable Resource Revenue	$ 2,767,000	$ 2,789,120	$ 8,947,873
Freehold Mineral Rights Tax	87,000	79,395	171,831
Industry Levies and Licenses	305,933	303,338	292,060
Other Revenue (Note 4)	65,059	89,349	28,490
Net Income from Government Business Enterprise	20,000	20,490	13,759
	3,244,992	3,281,692	9,454,013
Expenses - Directly Incurred (Schedule 2)			
Ministry Support Services	7,391	7,460	7,887
Resource Development and Management	94,019	101,508	100,979
Bioenergy Initiatives	92,000	70,498	70,275
Cost of Selling Oil	184,616	77,168	176,426
Energy Regulation	253,252	249,113	256,827
Utilities Regulation	36,940	33,293	33,741
Carbon Capture and Storage	291,700	159,873	53,914
Orphan Well Abandonment	30,500	31,111	15,760
Oil Sands Sustainable Development Secretariat	-	-	817
Settlements Related to the Land-Use Framework	-	-	4,123
	990,418	730,024	720,749
Net Operating Results	$ 2,254,574	$ 2,551,668	$ 8,733,264

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

MINISTRY OF ENERGY

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

As at March 31, 2016

(in thousands)

	2016 Actual	2015 (Restated) Actual (Note 19)
Financial Assets		
Cash and Cash Equivalents (Note 5)	$ 222,725	$ 300,994
Accounts Receivable (Notes 3, 6)	151,951	221,542
Inventory for Resale (Note 7)	277	1,226
Equity in Government Business Enterprise (Schedule 3)	34,965	14,475
	409,918	538,237
Liabilities		
Accounts Payable and Accrued Liabilities	382,361	637,923
Gas Royalty Deposits (Note 8)	212,952	247,777
Deferred Revenue	69,097	74,636
Security Deposits (Note 9)	138,125	122,835
Tenant Incentives (Note 10)	22,323	23,063
Pension Obligations (Note 11)	1,457	3,114
	826,315	1,109,348
Net Debt	(416,397)	(571,111)
Non-Financial Assets		
Tangible Capital Assets (Note 12)	95,054	101,102
Prepaid Expenses	12,333	11,530
Net Liabilities	(309,010)	(458,479)
Net (Liabilities)/Assets at Beginning of Year (Note 3)	(458,479)	1,208,187
Net Operating Results	2,551,668	8,733,264
Net Financing Provided For General Revenues	(2,402,199)	(10,399,930)
Net Liabilities at End of Year	$ (309,010)	$ (458,479)

Contractual Obligations and Contingent Liabilities (Notes 13 and 14)

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

MINISTRY OF ENERGY

CONSOLIDATED STATEMENT OF CHANGE IN NET DEBT

As at March 31, 2016

(in thousands)

	2016 Budget	2016 Actual	2015 Actual (Note 19)
Net Operating Results	$ 2,254,574	$ 2,551,668	$ 8,733,264
Acquisition of Tangible Capital Assets (Note 12)		(16,855)	(25,869)
Amortization of Tangible Capital Assets (Note 12)		22,517	21,035
Loss on Disposal of Tangible Capital Assets		368	780
Proceeds on Disposal of Tangible Capital Assets		18	51
Increase in Prepaid Expenses		(803)	(677)
Net Financing Provided For General Revenue		(2,402,199)	(10,399,930)
Decrease/(Increase) in Net Debt		154,714	(1,671,346)
Net (Debt)/Assets at Beginning of Year		(571,111)	1,100,235
Net Debt at End of Year		$ (416,397)	$ (571,111)

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

MINISTRY OF ENERGY

STATEMENT OF CASH FLOWS

Year ended March 31, 2016

(in thousands)

	2016 Actual	2015 (Restated) Actual (Note 19)
Operating Transactions		
Net Operating Results	$ 2,551,668	$ 8,733,264
Non-cash Items included in Net Operating Results		
Amortization of Tangible Capital Assets (Note 12)	22,517	21,035
Loss on Disposal of Tangible Capital Assets	368	780
	2,574,553	8,755,079
(Increase)/Decrease in Accounts Receivable	69,591	880,013
Decrease in Inventory for Resale	949	1,761
Increase in Prepaid Expenses	(803)	(677)
(Decrease)/Increase in Accounts Payable and Accrued Liabilities (Note 3)	(255,562)	409,532
Decrease in Deferred Revenue	(5,539)	(4,691)
Decrease in Tenant Incentives	(740)	(555)
Decrease in Pension Obligations	(1,657)	(942)
Cash Provided by Operating Transactions	2,380,792	10,039,520
Capital Transactions		
Acquisition of Tangible Capital Assets (Note 12)	(16,855)	(25,869)
Proceeds on Disposal of Tangible Capital Assets	18	51
Cash Applied to Capital Transactions	(16,837)	(25,818)
Investing Transactions		
Equity in Government Business Enterprise	(20,490)	(13,759)
Cash Provided by Investing Transactions	(20,490)	(13,759)
Financing Transactions		
Net Financing Provided for General Revenues	(2,402,199)	(10,399,930)
Decrease in Gas Royalty Deposits	(34,825)	(12,240)
Increase in Security Deposits	15,290	22,624
Cash Applied to Financing Transactions	(2,421,734)	(10,389,546)
Decrease in Cash and Cash Equivalents	(78,269)	(389,603)
Cash and Cash Equivalents at Beginning of Year	300,994	690,597
Cash and Cash Equivalents at End of Year	$ 222,725	$ 300,994

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

NOTE 1 AUTHORITY

The Minister of Energy has been designated as responsible for various Acts by the *Government Organization Act* and its regulations. To fulfill these responsibilities, the Minister administers the organizations listed below. The authority under which each organization operates is also listed. Together, these organizations form the Ministry of Energy.

Organization	Authority
Department of Energy (The Department)	*Government Organization Act*
Alberta Energy Regulator (The AER)	*Responsible Energy Development Act*
Alberta Utilities Commission (The AUC)	*Alberta Utilities Commission Act*
Alberta Petroleum Marketing Commission (The Commission)	*Petroleum Marketing Act (as amended on January 10, 2014) and the Natural Gas Marketing Act*
Post-Closure Stewardship Fund	*Mines and Minerals Act*

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES

These consolidated financial statements are prepared in accordance with Canadian Public Sector Accounting Standards.

(a) **Basis of Consolidation**

The Department of Energy, the AER, the AUC, and the Post-Closure Stewardship Fund, which all report under Canadian public sector accounting standards, are consolidated on a line by line basis. Intra-ministry transactions (revenue, expenses, capital, investing and financing transactions, and related asset and liability accounts) have been eliminated.

The Commission is a government business enterprise and is accounted for on a modified equity basis, with the equity being computed in accordance with International Financial Reporting Standards (IFRS). Under the modified equity method, the accounting policies of the Commission are not adjusted to conform to those of the Ministry of Energy. Inter-entity revenue and expense transactions and related asset and liability balances are not eliminated.

Under the proclamation of portions of the *Responsible Energy Development Act* (REDA) in June 2013, the AER was created and assumed all responsibilities of the ERCB including all assets, liabilities, obligations, commitments and contingencies. In November 2013, additional portions of REDA were proclaimed transferring the public land and geophysical jurisdictions. The remaining portions of REDA were proclaimed in March 2014 which transferred all environmental and water jurisdictions. The transfer of jurisdiction from ESRD to the AER represented the final step in creating a single regulator for upstream oil, oil sands, natural gas and coal development in Alberta.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (cont'd)

(b) Basis of Financial Reporting

Revenues

All revenues are reported on the accrual basis of accounting. Cash received for which goods or services have not been provided by year end is recorded as deferred revenue. The provincial royalty system is predicated on self-reporting where the petroleum and natural gas industry is expected to understand the relevant energy legislation (statutes and regulations) and comply with them. This has an impact on the completeness of revenue when the petroleum and natural gas industry do not fully meet the legislative requirements and, for example, report inaccurate or incomplete production data. The ministry has implemented systems and controls to detect and correct situations where the petroleum and natural gas industry has not complied with the various Acts and Regulations the ministry administers. These systems and controls, based on areas of highest risk, include performing audits of the petroleum and natural gas industry records where determined necessary by the ministry. The ministry does not estimate the effect of misreported revenue. Any impacts on revenue of refiling by industry are recognized in the year of refiling.

Crude oil and natural gas royalties are determined based on monthly production. Revenue is recognized when the resource is produced by the mineral rights holders.

Bitumen royalty is determined based on revenues from production sold by projects less the costs of that production and the costs of selling the Crown's royalty share. Royalty revenue is recognized when the resource is produced by the mineral rights holders.

Freehold mineral rights taxes are determined at the end of a calendar year based on production and costs of production incurred in the calendar year. Revenue is recognized on a prorated basis, by month, of the estimated calendar year taxes that will be due to the Crown.

Revenue from bonuses and sales of Crown leases is recognized when the Crown leases are sold. Rentals and fees revenue is recognized over the term of the leases.

Industry levies and assessments are recognized as revenue in the year receivable.

Revenues for the Post Closure Stewardship Fund are based on reported injection of volumes of carbon dioxide 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.

Expenses

<u>Directly Incurred</u>

Directly incurred expenses are those costs the ministry has primary responsibility and accountability for, as reflected in the government's budget documents.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (cont'd)

(b) Basis of Financial Reporting (cont'd)

Directly Incurred (cont'd)

In addition to program operating expenses such as salaries, supplies, etc., directly incurred expenses also include:

- amortization of tangible capital assets,
- pension costs, which are the cost of employer contributions for current service of employees during the year. The AER and the AUC have their own defined benefit pension plans. The AER's and the AUC's pension expense 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 retirement age of employees. Net accumulated actuarial gain or loss is deferred and amortized over the average remaining service period of the active employees, which is 7 years. For the purpose of calculating the expected return, plan assets are valued at fair value. Past service costs arising from plan amendments are accounted for in the period of the plan amendment.
- valuation adjustments which include changes in the valuation allowances used to reflect financial assets at their net recoverable or other appropriate value. Valuation adjustments also represent the change in management's estimate of future payments arising from obligations relating to vacation pay, guarantees and indemnities.

Grants are recognized as expenses when authorized and eligibility criteria, if any, are met.

Incurred by Others

Services contributed by other entities in support of the department operations are not recognized and are disclosed in Schedule 4.

Valuation of Financial Assets and Liabilities

Fair value is the amount of consideration agreed upon in an arm's length transaction between knowledgeable, willing parties who are under no compulsion to act.

The fair values of Cash and Cash Equivalents, Accounts Receivable, Loans and Advances, and Accounts Payable and Accrued Liabilities are estimated to approximate their carrying values because of the short term nature of these instruments.

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 of the ministry are limited to financial claims, such as advances to and receivables from other organizations, employees and other individuals, as well as inventories held for resale.

Assets acquired by right are not included.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (cont'd)

(b) **Basis of Financial Reporting (cont'd)**

Financial Assets (cont'd)

Accounts Receivable

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

Inventory for Resale

Inventory consists of conventional and synthetic oil in feeder and trunk pipelines. Inventories are stated at lower of cost or net realizable value.

Liabilities

Liabilities are recorded to the extent that they represent present obligations as a result of events and transactions occurring prior to the end of fiscal year. The settlement of liabilities will result in sacrifice of economic benefits in the future.

Liabilities include all financial claims payable by the ministry at fiscal year end.

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 government services;
b) may be consumed in the normal course of operations; and
c) are not for sale in the normal course of operations.

Non-financial assets of the ministry are limited to tangible capital assets.

Tangible capital assets of the ministry are recorded at historical cost and amortized on a straight-line basis over the estimated useful lives of the assets. The threshold for capitalizing new systems development is $250,000 and the threshold for major systems enhancements is $100,000. The threshold for all other tangible capital assets is $5,000.

Amortization is only charged if the tangible capital asset is put into service.

When tangible capital assets are gifted or sold for a nominal sum, the net book values of these assets less any nominal proceeds are recorded as grants in kind.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (cont'd)

(b) Basis of Financial Reporting (cont'd)

Measurement Uncertainty
(in thousands)

Measurement uncertainty exists when there is a variance between the recognized or disclosed amount and another reasonably possible amount. Natural gas and by-products revenue recorded as $493,032, bitumen royalty recorded as $1,222,971, and crude oil royalty revenue recorded as $688,800 in these financial statements are subject to measurement uncertainty.

Natural gas and by-products revenue is calculated based on allowable costs incurred by the royalty payers and production volumes that are reported to the ministry by royalty payers. Industry may modify their royalty and gas cost allowance for non-statute barred years. These amounts could vary significantly from that which was initially reported. The ministry estimates what the costs, volumes and royalty rates for the fiscal year should be based on statistical analysis of industry data. Based on historical data, changes to natural gas and by-products revenues was $153,341.

For projects from which bitumen royalty is paid and the project has reached payout, the royalty rate used to determine the royalties is based on the average price of West Texas Intermediate crude oil in Canadian dollars for the calendar year. Royalty rates will start at 25% of net profits when oil is priced at fifty five dollars per barrel or less, and increase to a maximum of 40% of net profits when oil is priced at one hundred and twenty dollars or more. Payout is defined at the first date at which the cumulative revenue of a project first equals the cumulative cost of the project.

The Ministry, through its agent Alberta Petroleum Marketing Commission (APMC), is party to the North West Redwater Partnership and the Energy East Pipeline Projects. The Ministry has used judgement to estimate the net present value of the processing agreement with the North West Redwater Partnership, as well as to estimate the monthly toll commitments as disclosed in Schedule 3 to the consolidated financial statements.

(c) Change in Accounting Policy

A net debt presentation (with reclassification of comparatives) has been adopted for the presentation of financial statements. Net Debt or Net Financial Assets is measured as the difference between the ministry's financial assets and liabilities.

The effect of this change results in changing the presentation of the Statement of Financial Position and adding an additional Statement of Change in Net Debt.

(d) Future Accounting Changes

In June 2015 the Public Sector Accounting Board issued these following accounting standards:

- **PS2200 Related Party Disclosures** and **PS3420 Inter-Entity Transactions (effective April 1, 2017)**
  PS 2200 defines a related party and establishes disclosures required for related party transactions; PS3240 establishes standards on how to account for and report transactions between public sector entities that comprise a government's reporting entity from both a provider and recipient perspective. Management is currently assessing the impact of these standards on the financial statements.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (cont'd)

(d) **Future Accounting Changes (cont'd)**

- **PS3210 Assets**, **PS3320 Contingent Assets**, and **PS3380 Contractual Rights (effective April 1, 2017)**
  PS3210 provides guidance for applying the definition of assets set out in FINANCIAL STATEMENT CONCEPTS, Section PS1000 establishes general disclosure standards for assets; PS3320 defines and establishes disclosure standards on contingent assets; PS3380 defines and establishes disclosure standards on contractual rights. Management is currently assessing the impact of these standards on the financial statements.

NOTE 3 PRIOR PERIOD RESTATEMENT

The Energy Utilities Board issued Guide 46 of the “Production Audit Handbook” in January 2003 with potential natural gas royalty implications. In fiscal 2005-2006, the ministry made an accounting estimate based on interpretation of the Guide. The reversal of this estimate was missed in the following fiscal year and this error has been carried into future fiscal years.

The correction of this error is being made in fiscal 2015-16 and is accounted for retrospectively by restating fiscal 2014-15 comparatives. The impacts are reductions to Accounts Receivable and Net Assets by $237 million.

NOTE 4 OTHER REVENUE

(in thousands)

	2016	2015 (Restated)
Disgorgement Payment and Monetary Penalty to TransAlta Corporation	$ 51,921	$ -
Settlements Related to the Land-Use Framework	25,891	-
Other Revenue	11,537	28,490
	$ 89,349	$ 28,490

Disgorgement Payment and Monetary Penalty to TransAlta Corporation
The disgorgement payment and the monetary penalty levied against TransAlta Corporation of $51,921 have been reflected in these financial statements in accordance with the provisions set out in AUC Decision 3110-D03-2015.

Settlements Related to the Land-Use Framework
All provisions for the settlements related to energy lease cancellation associated with the Land-Use Framework for the Lower Athabasca Regional Plan and the Urban Development Sub-Region were settled in Fiscal 2015-16. These land lease cancellations were made under section 8(1)(c) of the Mines and Minerals Act and the compensation amount as determined under the Mineral Rights Compensation Regulation. No right of review, recalculation, or appeal of the compensation amount is provided for under these legislations.

NOTE 4 OTHER REVENUE (cont'd)
(in thousands)

Settlements Related to the Land-Use Framework (cont'd)
The estimated settlements were based upon the bonus bids, application fees, and the annual rental paid and/or expected to be paid by the lessees prior to the settlement. The development and abandonment costs were estimated by the ministry based upon information provided by the lessees. Interest provisions were also made based on the projected settlement date of these claims as provided for in the Regulation. The settlements were reflected as a reduction of revenue in the years when the original estimates were made.

Upon submission of final documentation from the lessees, the actual settlements were $25,891 lower than booked. The effect of this change is a reduction to Liabilities and an increase in Other Revenues, in accordance the Government of Alberta's accounting treatment of an over accrual of prior year's expenditures.

NOTE 5 CASH AND CASH EQUIVALENTS

Cash consists of deposits in the Canadian financial institutions which are managed by the Province of Alberta with the objective of providing competitive interest income to depositors 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.

NOTE 6 ACCOUNTS RECEIVABLE

Accounts receivable royalties are secured by a claim against the mineral leases and are interest bearing in accordance with the applicable legislation.

NOTE 7 INVENTORY FOR RESALE

Inventory reported consists of crude oil inventory held for selling by APMC. Inventory is calculated based on inventory volumes held in various revenue pools multiplied by average pricing.

NOTE 8 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.

NOTE 9 SECURITY DEPOSITS
(in thousands)

The ministry encourages the timely and proper abandonment and reclamation of upstream wells, facilities, pipelines, and oilfield waste management facilities by holding various forms of security. At March 31, 2016, the ministry held $138,125 (2015 - $122,835) in cash and an additional $1,528,339 (2015 - $1,707,241) in letters of credit. The security, along with any interest earned, will be returned to the depositor upon meeting specified refund criteria.

NOTE 10 TENANT INCENTIVES

(in thousands)

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

	2016			2015
	Leasehold Improvement Costs	**Reduced Rent Benefits and Rent-Free Periods**	**Total**	**Total**
Beginning of Year	$ 18,331	$ 4,692	$ 23,023	$ 23,535
Additions During Year	763	-	763	918
Amortization	(1,195)	(327)	(1,522)	(1,430)
End of Year	$ 17,899	$ 4,365	$ 22,264	$ 23,023

The AUC entered into a lease agreement which provides a lease incentive of $418 comprised of leasehold improvement costs and/or rent-free periods beginning July, 2016. The deferred lease incentive is amortized on a straight line basis over the term of the lease.

	2016			2015
	Leasehold Improvement Costs	**Reduced Rent Benefits and Rent-Free Periods**	**Total**	**Total**
Beginning of Year	$ 40	$ -	$ 40	$ 83
Additions During Year	59	-	59	-
Amortization	(40)	-	(40)	(43)
End of Year	$ 59	$ -	$ 59	$ 40

NOTE 11 PENSION OBLIGATIONS

(in thousands)

The ministry participates in multi-employer pension plans, Management Employees Pension Plan and Public Service Pension Plan and Supplementary Retirement Plan for Public Service Managers. The expense for these pension plans is equivalent to the annual contributions of $30,145 for the year ended March 31, 2016 (2015 - $29,471). The ministry is not responsible for future funding of the plan deficit other than through contribution increases.

At December 31, 2015, the Management Employees Pension Plan reported a surplus of $299,051 (2014 - surplus $75,805), the Public Service Pension Plan reported a deficiency of $133,188 (2014 deficiency - $803,299) and the Supplementary Retirement Plan for Public Service Managers reported a deficiency of $16,305 (2014 - deficiency $17,203).

NOTE 11 PENSION OBLIGATIONS (cont'd)

(in thousands)

The ministry also participates in two multi-employer Long Term Disability Income Continuance Plans. At March 31, 2016, the Bargaining Unit Plan reported an actuarial surplus of $83,006 (2015 - surplus $86,888) and the Management, Opted Out and Excluded Plan an actuarial surplus of $29,246 (2015 - surplus $32,343). The expense for these two plans is limited to the employer's annual contributions for the year.

In addition, the AER and the AUC maintain their 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, 2014. The accrued benefit obligation as at March 31, 2016 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, 2017.

Pension plan assets are valued at market values. Significant weighted average actuarial and economic assumptions used to value accrued benefit obligations and pension benefit costs are as follows:

	AER		AUC	
	2016	2015	2016	2015
Weighted average actual return	-3.4%	11.7%	-1.7%	11.3%
Accrued benefits obligations				
Discount rate	4.7%	4.9%	4.5%	4.7%
Rate of compensation increase	0% for 2 years, 3.5% thereafter	0% for 1 year, 3.5% thereafter	3.5%	3.5%
Long – term inflation rate	2.0%	2.0%	2.0%	2.0%
Pension benefit costs for the year				
Discount rate	4.9%	5.3%	4.7%	5.0%
Expected rate of return on plan assets	4.9%	5.3%	4.7%	5.0%
Rate of compensation increase	0% for 1 year, 3.5% thereafter	3.8%	3.5%	3.8%
Funded status and amounts				
Market value of plan assets	$ 47,853	$ 45,087	$ 8,543	$ 8,092
Accrued benefit obligation	54,639	49,510	10,224	9,384
Plan (deficit)	(6,786)	(4,423)	(1,681)	(1,292)
Unamortized actuarial loss	6,094	2,074	916	527
Pension obligations	$ (692)	$ (2,349)	$ (765)	$ (765)

NOTE 11 PENSION OBLIGATIONS (cont'd)

(in thousands)

	AER 2016	AER 2015	AUC 2016	AUC 2015
Pension benefit costs				
Current period benefit costs	$ 4,375	$ 3,625	$ 647	$ 627
Interest cost	2,573	2,394	464	427
Expected return on plan assets	(2,330)	(2,110)	(397)	(357)
Amortization of actuarial losses	436	396	113	105
	$ 5,054	$ 4,305	$ 827	$ 802
Additional information				
Employer contribution	$ 6,711	$ 5,247	$ 827	$ 802
Employees' contribution	861	731	112	113
Benefit paid	3,216	3,350	346	420
Asset Allocation				
Equity securities	47.9%	49.9%	48.4%	51.7%
Debt securities	37.7%	38.4%	28.4%	29.4%
Other	14.4%	11.7%	23.2%	18.9%
	100.0%	100.0%	100.0%	100.0%

NOTE 12 TANGIBLE CAPITAL ASSETS

(in thousands)

	Land	Leasehold Improvements	Equipment [1]	Computer Hardware/ Software	Total
Estimated Useful Life	indefinite	lease term	3-40 years	3-10 years	
Historical Cost [2]					
Beginning of Year	$ 282	$ 39,402	$ 46,158	$ 230,569	$ 316,411
Additions	-	2,952	848	13,055	16,855
Disposals, Including Write-downs		(218)	(14,837)	(12,252)	(27,307)
	$ 282	$ 42,136	$ 32,169	$ 231,372	$ 305,959

[1] Equipment includes office equipment and furniture and other equipment.

[2] Historical cost includes work-in-progress at March 31, 2016 totaling $3,866 (2015 - $454) comprised of computer hardware and software.

NOTE 12 TANGIBLE CAPITAL ASSETS (cont'd)

(in thousands)

	Land	Leasehold Improvements	Equipment [(1)]	Computer Hardware/ Software	Total
Accumulated Amortization					
Beginning of Year	$ -	$ 10,011	$ 31,754	$ 173,544	$ 215,309
Amortization Expense	-	2,641	3,174	16,702	22,517
Effect of Disposals	-	(86)	(14,646)	(12,189)	(26,921)
	$ -	$ 12,566	$ 20,282	$ 178,057	$ 210,905
Net Book Value at March 31, 2016	$ 282	$ 29,570	$ 11,887	$ 53,315	$ 95,054
Net Book Value at March 31, 2015	$ 282	$ 29,391	$ 14,404	$ 57,025	$ 101,102

NOTE 13 CONTRACTUAL OBLIGATIONS

(in thousands)

As at March 31, 2016, the ministry had contractual obligations totaling $1,003,579 (2015 - $1,267,115).

Contractual obligations are obligations of the ministry to others that will become liabilities in the future when the terms of those contracts or agreements are met. These amounts include obligations under long-term contracts with contract payment requirements for each of the next five years and thereafter are as follows:

	Grant Agreements	Service Contracts	Long-Term Leases	Total
2017	$ 267,850	$ 20,888	$ 28,788	$ 317,526
2018	69,400	287	23,251	92,938
2019	69,400	103	16,919	86,422
2020	49,600	5	12,712	62,317
2021	49,600	3	12,502	62,105
Thereafter	272,750	-	109,521	382,271
	$ 778,600	$ 21,286	$ 203,693	$ 1,003,579

NOTE 14 CONTINGENT LIABILITIES

(in thousands)

The ministry is involved in legal matters where damages are being sought. These matters may give rise to contingent liabilities. Accruals have been made in specific instances where it is likely that losses will be incurred based on a reasonable estimate.

The ministry has been named in five claims (2015 restated - two), all with outcomes that are not determinable. Three claims have specified amounts of $7,158 (2015 one claim of $7,000) and two claim (2015 restated - one) has no specified amounts.

NOTE 14 CONTINGENT LIABILITIES (con'td)

(in thousands)

The ministry has been jointly named with other entities in seven claims (2015 restated - six). Five of these claims have specified amounts totaling $14,350 (2015 restated – five claims totaling $14,350) and two claims (2015 restated - one) with no amounts specified.

Of the total specified claims, two claims totaling $10,007 (2015 - two claims totaling $10,007) are partially or fully covered by the Alberta Risk Management Fund.

The resolution of the indeterminable claim may result in a liability, if any, that may be significantly lower than the claimed amount.

NOTE 15 TRUST FUNDS UNDER ADMINSTRATION

(in thousands)

The ministry administers the Oil and Gas Conservation Trust consisting of public money over which the Legislature has no power of appropriation. Because the Province has no equity in the fund and administers the fund for the purpose of various trusts, the fund is not included in the ministry's financial statements.

As at March 31, 2016, the funds in the Oil and Gas Conservation Trust are $4,594 (2015 - $4,463).

NOTE 16 RELATED PARTY TRANSACTIONS

(in thousands)

The ministry paid $5,699 (2015 - $6,843) to various other Government of Alberta departments, agencies or funds for grants, supplies and/or services during the fiscal year and received $140 (2015 - $127) as revenue.

Alberta Petroleum Marketing Commission has borrowed $324 million from Treasury Board and Finance and advanced the funds to the partnership. For more details, see schedule 3.

Accommodations, legal, business services, and certain financial costs were provided to the ministry by other government organizations at no cost. However, services contributed by other entities in support of the ministry operations are disclosed in Schedule 4.

NOTE 17 ROYALTY REDUCTION PROGRAMS

(in thousands)

The ministry provides eleven oil and gas royalty reduction programs. The intent of these programs is to encourage industry to produce from wells which otherwise would not be economically productive. For the year ended March 31, 2016, the royalties received under these programs were reduced by $850,912 (2015 restated - $1,442,873).

NOTE 18 BITUMEN CONSERVATION

(in thousands)

In 2004-05 the Alberta Energy and Utilities (EUB) Board (now known as the AER) released its Bitumen Conservation Requirements decisions regarding the status of natural gas wells in the Wabiskaw-McMurray region of the Athabasca Oil Sands area. The decisions recommended the shut-in of Wabiskaw-McMurray natural gas totaling about 53.6 billions of cubic feet annually to protect about 25.5 billion barrels of potentially recoverable bitumen. The Natural Gas Royalty Regulations, 2002 was amended to provide a royalty mechanism that would allow the Minister of Energy to calculate a royalty adjustment each month for gas producers affected by the EUB decisions. The Natural Gas Royalty Regulations, 2002 was also amended to provide for the royalty adjustment to be recovered through additional royalty on the shut-in wells when they return to production through amendments to the provisions that deal with the calculation of the royalty share of gas. The amendments provide for an increase over and above the usual royalty rate, and extend to new wells that produce from the shut-in zone. The effect of these adjustments was to reduce natural gas and by-products revenue by $12,139 (2015 - $26,374).

NOTE 19 COMPARATIVE FIGURES

Certain 2015 figures have been reclassified to conform to 2016 presentation.

NOTE 20 APPROVAL OF FINANCIAL STATEMENTS

The financial statements were approved by the Senior Financial Officer and the Deputy Minister.

MINISTRY OF ENERGY **Schedule 1**

CONSOLIDATED SCHEDULE TO FINANCIAL STATEMENTS

REVENUES

Year ended March 31, 2016

(in thousands)

	2016		2015
	Budget	Actual	Actual (Note19)
Non-Renewable Resource Revenue (Note 17)			
Bitumen Royalty	$ 1,547,000	$ 1,222,971	$ 5,049,393
Crude Oil Royalty	536,000	688,800	2,244,745
Natural Gas and By-Products Royalty (Note 18)	343,000	493,032	989,160
Bonuses and Sales of Crown Leases	181,000	203,267	476,331
Rentals and Fees	145,000	167,382	172,489
Coal Royalty	15,000	13,668	15,755
	2,767,000	2,789,120	8,947,873
Freehold Mineral Rights Tax	87,000	79,395	171,831
Industry Levies and Licenses	305,933	303,338	292,060
Other Revenue (Note 4)	65,059	89,349	28,490
	3,224,992	3,261,202	9,440,254
Net Income from Government Business Enterprise	20,000	20,490	13,759
Total Revenue	$ 3,244,992	$ 3,281,692	$ 9,454,013

MINISTRY OF ENERGY **Schedule 2**

CONSOLIDATED SCHEDULE TO FINANCIAL STATEMENTS

EXPENSES - DIRECTLY INCURRED

Year ended March 31, 2016

(in thousands)

	2016 Budget	2016 Actual	2015 Actual (Note 19)
Salaries, Wages and Employee Benefits	$ 289,136	$ 283,603	$ 285,016
Grants	379,768	230,902	122,543
Supplies and Services	271,126	162,393	272,823
Orphan Well Abandonment	30,500	31,111	15,760
Amortization of Tangible Capital Assets (Note 12)	19,888	22,517	21,035
Other	-	64	68
Settlements Related to the Land-Use Framework	-	-	4,123
Total Expenses before Recoveries	990,418	730,590	721,368
Less Recovery from Support Service Arrangements with Related Parties [1]	-	(566)	(619)
	$ 990,418	$ 730,024	$ 720,749

[1] The ministry provides financial services to the ministry of Environment and Parks. Costs incurred by the ministry for these services are recovered from the ministry of Environment and Parks.

MINISTRY OF ENERGY **Schedule 3**

CONSOLIDATED SCHEDULES TO FINANCIAL STATEMENTS

EQUITY IN GOVERNMENT BUSINESS ENTERPRISE

Year ended March 31, 2016

(in thousands)

	2016	2015
Accumulated surplus		
Opening accumulated surplus - Alberta Petroleum Marketing Commission	$ 14,475	$ 716
Revenues		
Marketing of Oil	3,820	7,681
Financing Transactions	23,780	12,738
Total revenue	27,600	20,419
Total expense	7,110	6,660
Net income for the year	20,490	13,759
Accumulated surplus at end of year	$ 34,965	$ 14,475
Represented by		
Cash and short-term investments	$ 2,490	$ 5,919
Due from the Department of Energy	-	3,346
Term Loan	360,881	237,738
Other assets	34,972	42,202
Total assets	398,343	289,205
Liabilities		
Accounts payable	6,999	13,443
Due to Government of Alberta	327,888	226,426
Due to the Department of Energy	28,491	34,861
Total liabilities	363,378	274,730
	$ 34,965	$ 14,475

COMMITMENTS *(in thousands)*

(a) North West Redwater Partnership

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 and market Crown royalty bitumen, or equivalent volumes, collected pursuant to the Bitumen Royalty in Kind initiative in order to capture additional value within Alberta. NWRP will market the refined products (primarily ultra low sulphur diesel and low sulphur vacuum gas oil) on behalf of the 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.

(in thousands)

(a) North West Redwater Partnership (cont'd)

Under the processing agreement, 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 $8.5 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 term of the commitment begins upon the commencement of commercial operations. No amounts have been paid under this agreement to date.

The nominal tolls under the processing agreement, assuming an $8.5 billion Facility Capital Cost, market interest rates and 2% operating cost inflation rate, are estimated above. The total estimated tolls have been reduced by $1.26 billion relative to March 2015, due primarily to lower debt tolls. As at March 31, 2016 NWRP has issued $3.65 billion in bonds at lower than anticipated rates and expects future bond offerings to continue this trend.

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

(b) North West Redwater Partnership Monthly Toll Commitment

The Commission 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.

The future toll commitments are estimated to be:

2016-17	$ -
2017-18	$ 261,000
2018-19	$ 656,000
2019 -20	$ 763,000
2020-21	$ 904,000
Beyond March 2021	$ 22,166,000

(c) Term Loan Provided to North West Redwater Partnership

As part of the Subordinated Debt Agreement with the Partnership, the Commission provided a $324 million loan. These amounts plus the accrued interest will be repaid on a straight line basis over ten years by the Partnership beginning one year after commercial start-up of the Sturgeon Refinery. Upon initiation of commercial operations the total amount of the term loan will be adjusted to reflect an agreed equity to debt ratio.

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

(in thousands)

(d) North West Redwater Partnership 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.

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

(e) Energy East Pipeline Project

The Commission has signed a Transportation Service Agreement (TSA) with Energy East Pipeline Limited Partnership (the "Carrier") to purchase 100,000 barrels per day of firm capacity for a term of 20 years to transport volumes of crude oil. The construction of the pipeline is dependent upon obtaining regulatory approval. The Carrier filed an updated project cost estimate with the National Energy Board (NEB) in December 2015. Under the take-or-pay obligation, once required regulatory and commercial approvals are obtained the Commission has an estimated updated minimum obligation to pay $4.6 billion ($3.4 billion – 2015) in tolls over the 20 year term. Additional tolls will be incurred depending on the volumes transported through the pipeline. The pipeline is expected to be in service as early as 2020.

The future toll commitments are estimated to be:

2016-17	$ -
2017-18	$ -
2018-19	$ -
2019 -20	$ 60,000
2020-21	$ 230,000
Beyond March 2021	$ 4,310,000

MINISTRY OF ENERGY **Schedule 4**

CONSOLIDATED SCHEDULE TO FINANCIAL STATEMENTS

ALLOCATED COSTS

Year ended March 31, 2016

(in thousands)

		2016				2015
		Expenses - Incurred by Others				(Note 19)
Program	**Expenses [1]**	**Accommodation Costs [2]**	**Legal Services [3]**	**Business Services [4]**	**Total Expenses**	**Total Expenses**
Ministry Support Services	$ 7,460	$ 530	$ 1,935	$ -	$ 9,925	$ 9,727
Resource Development and Management	101,508	5,798	3,113	2,789	$ 113,208	113,354
Bioenergy Initiatives	70,498	84	-	-	$ 70,582	70,318
Cost of Selling Oil	77,168	-	-	-	$ 77,168	176,426
Energy Regulation	249,113	-	-	-	$ 249,113	256,827
Utilities Regulation	33,293	-	-	-	$ 33,293	33,741
Carbon Capture and Storage	159,873	65	-	-	$ 159,938	54,001
Orphan Well Abandonment	31,111	-	-	-	$ 31,111	15,760
Settlements Related to the Land-Use Framework	-	-	-	-	$ -	4,123
	$ 730,024	$ 6,477	$ 5,048	$ 2,789	$ 744,338	$ 734,277

(1) Expenses - Directly Incurred as per Statement of Operations.

(2) Costs shown for Accommodation are allocated by budgeted Full-Time Equivalent Employment.

(3) Costs shown for Legal Services are allocated by estimated costs incurred by each program.

(4) Costs shown for Business Service include charges for information technology support, vehicles, internal audit services and other services are allocated by costs in certain programs.

DEPARTMENT OF ENERGY

FINANCIAL STATEMENTS
For the year ended March 31, 2016

Independent Auditor's Report

AUDITOR GENERAL *Alberta*

To the Minister of Energy

Report on the Financial Statements

I have audited the accompanying financial statements of the Department of Energy, which comprise the statement of financial position as at March 31, 2016, and the statements of operations, change in net debt and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these 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 financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

My responsibility is to express an opinion on these financial statements based on my audit. I conducted my audit in accordance with Canadian generally accepted auditing standards. Those standards require that I comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements 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 entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my audit opinion.

Opinion

In my opinion, the financial statements present fairly, in all material respects, the financial position of the Department of Energy as at March 31, 2016, and the results of its operations, its changes in net debt and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Original signed by Merwan N. Saher, FCPA, FCA
Auditor General

June 6, 2016

Edmonton, Alberta

DEPARTMENT OF ENERGY

STATEMENT OF OPERATIONS

Year ended March 31, 2016

(in thousands)

	2016 Budget	2016 Actual	2015 Actual (Note 17)
Revenues (Schedule 1)			
Non-Renewable Resource Revenue	$ 2,767,000	$ 2,789,120	$ 8,947,873
Freehold Mineral Rights Tax	87,000	79,395	171,831
Other Revenue (Note 4)	56,500	81,137	18,458
	2,910,500	2,949,652	9,138,162
Expenses - Directly Incurred (Schedule 2)			
Ministry Support Services	7,391	7,460	7,887
Resource Development and Management	94,019	101,583	101,125
Bioenergy Initiatives	92,000	70,498	70,275
Cost of Selling Oil	184,616	77,168	176,426
Oil Sands Sustainable Development Secretariat	-	-	817
Energy Regulation	-	-	19,800
Settlements Related to the Land-Use Framework	-	-	4,123
Carbon Capture and Storage	291,700	159,873	53,914
	669,726	416,582	434,367
Net Operating Results	$ 2,240,774	$ 2,533,070	$ 8,703,795

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

DEPARTMENT OF ENERGY

STATEMENT OF FINANCIAL POSITION

As at March 31, 2016

(in thousands)

	2016 Actual	2015 (Restated) Actual (Note 17)
Financial Assets		
Cash and Cash Equivalents (Note 5)	$ 47,876	$ 112,374
Accounts Receivable (Notes 3, 6)	133,431	213,183
Inventory for Resale (Note 7)	277	1,226
	181,584	326,783
Liabilities		
Accounts Payable and Accrued Liabilities (Note 8)	347,633	590,151
Gas Royalty Deposits (Note 9)	212,952	247,777
Deferred Revenue	67,493	72,580
	628,078	910,508
Net Debt	(446,494)	(583,725)
Non-Financial Assets		
Tangible Capital Assets (Note 10)	24,275	30,635
Net Liabilities	(422,219)	(553,090)
Net (Liabilities)/Assets at Beginning of Year (Note 3)	(553,090)	1,143,045
Net Operating Results	2,533,070	8,703,795
Net Financing Provided For General Revenues	(2,402,199)	(10,399,930)
Net Liabilities at End of Year	$ (422,219)	$ (553,090)

Contingent Liabilities and Contractual Obligations (Notes 11 and 12)

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

DEPARTMENT OF ENERGY

STATEMENT OF CHANGE IN NET DEBT

As at March 31, 2016

(in thousands)

	2016 Budget	2016 Actual	2015 (Restated) Actual (Note 17)
Net Operating Results	$ 2,240,774	$ 2,533,070	$ 8,703,795
Acquisition of Tangible Capital Assets		(1,913)	(3,974)
Amortization of Tangible Capital Assets (Note 10)		8,257	7,771
Proceeds on Sale of Tangible Capital Assets		16	51
Net Financing Provided For General Revenue		(2,402,199)	(10,399,930)
Decrease/(Increase) in Net Debt		137,231	(1,692,287)
Net (Debt)/Assets at Beginning of Year		(583,725)	1,108,562
Net Debt at End of Year		$ (446,494)	$ (583,725)

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

DEPARTMENT OF ENERGY

STATEMENT OF CASH FLOWS

Year ended March 31, 2016

(in thousands)

	2016 Actual	2015 (Restated) Actual (Note 17)
Operating Transactions		
Net Operating Results	$ 2,533,070	$ 8,703,795
Non-cash Items included in Net Operating Results		
Amortization of Tangible Capital Assets (Note 10)	8,257	7,771
	2,541,327	8,711,566
Decrease in Accounts Receivable	79,752	888,816
Decrease in Inventory	949	1,761
(Decrease)/Increase in Accounts Payable and Accrued Liabilities	(242,518)	393,999
Decrease in Deferred Revenue	(5,087)	(3,776)
Cash Provided by Operating Transactions	2,374,423	9,992,366
Capital Transactions		
Acquisition of Tangible Capital Assets (Note 10)	(1,913)	(3,974)
Proceeds from Disposal of Tangible Capital Assets (Note 10)	16	51
Cash Applied to Capital Transactions	(1,897)	(3,923)
Financing Transactions		
Net Financing Provided for General Revenues	(2,402,199)	(10,399,930)
Decrease in Gas Royalty Deposits	(34,825)	(12,239)
Cash Applied to Financing Transactions	(2,437,024)	(10,412,169)
Decrease in Cash and Cash Equivalents	(64,498)	(423,726)
Cash and Cash Equivalents at Beginning of Year	112,374	536,100
Cash and Cash Equivalents at End of Year	$ 47,876	$ 112,374

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

NOTE 1 AUTHORITY

The Department of Energy operates under the authority of the *Government Organization Act* , Chapter G-10, Revised Statutes of Alberta 2000.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES

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

(a) **Reporting Entity**

The reporting entity is the Department of Energy, which is part of the Ministry of Energy and for which the Minister of Energy is accountable. Other entities reporting to the Minister are the Alberta Petroleum Marketing Commission (APMC), the Alberta Energy Regulator (AER) and the Alberta Utilities Commission (AUC). The activities of these organizations are not included in these financial statements. The ministry annual report provides a more comprehensive accounting of the financial position and results of the ministry's operations for which the minister is accountable.

All departments of the Government of Alberta operate within the General Revenue Fund (the Fund). The Fund is administered by the President of Treasury Board and Minister of Finance. All cash receipts of departments are deposited into the Fund and all cash disbursements made by departments are paid from the Fund. Net Financing provided from (for) General Revenues is the difference between all cash receipts and all cash disbursements made.

(b) **Basis of Financial Reporting**

Revenues

All revenues are reported on the accrual basis of accounting. Cash received for which goods or services have not been provided by year end is recorded as deferred revenue. The provincial royalty system is predicated on self-reporting where the petroleum and natural gas industry is expected to understand the relevant energy legislation (statutes and regulations) and comply with them. This has an impact on the completeness of revenue when the petroleum and natural gas industry do not fully meet the legislative requirements and, for example, report inaccurate or incomplete production data. The department has implemented systems and controls to detect and correct situations where the petroleum and natural gas industry has not complied with the various Acts and Regulations the department administers. These systems and controls, based on areas of highest risk, include performing audits of the petroleum and natural gas industry records where determined necessary by the department. The department does not estimate the effect of misreported revenue. Any impacts on revenue of refiling by industry are recognized in the year of refiling.

Crude oil and natural gas royalties are determined based on monthly production. Revenue is recognized when the resource is produced by the mineral rights holders.

Bitumen royalty is determined based on revenues from production sold by projects less the costs of that production and the costs of selling the Crown's royalty share. Royalty revenue is recognized when the resource is produced by the mineral rights holders.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (cont'd)

(b) Basis of Financial Reporting (cont'd)

Revenues (cont'd)

Freehold mineral rights taxes are determined at the end of a calendar year based on production and costs of production incurred in the calendar year. Revenue is recognized on a prorated basis, by month, of the estimated calendar year taxes that will be due to the Crown.

Revenue from bonuses and sales of Crown leases is recognized when the Crown leases are sold. Rentals and fees revenue is recognized over the term of the leases.

Expenses

Directly Incurred

Directly incurred expenses are those costs the department has primary responsibility and accountability for, as reflected in the government's budget documents.

In addition to program operating expenses such as salaries, supplies, etc., directly incurred expenses also include:

- amortization of tangible capital assets,
- pension costs, which are the cost of employer contributions for current service of employees during the year, and
- valuation adjustments which include changes in the valuation allowances used to reflect financial assets at their net recoverable or other appropriate value. Valuation adjustments also represent the change in management's estimate of future payments arising from obligations relating to vacation pay, guarantees and indemnities.

Grants are recognized as expenses when authorized and eligibility criteria, if any, are met.

Incurred by Others

Services contributed by other entities in support of the department operations are not recognized and are disclosed in Schedule 5 and allocated to programs in Schedule 6.

Valuation of Financial Assets and Liabilities

Fair value is the amount of consideration agreed upon in an arm's length transaction between knowledgeable, willing parties who are under no compulsion to act.

The fair values of Cash and Cash Equivalents, Accounts Receivable, Loans and Advances, and Accounts Payable and Accrued Liabilities are estimated to approximate their carrying values because of the short term nature of these instruments.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (cont'd)

(b) **Basis of Financial Reporting (cont'd)**

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 of the department are limited to financial claims, such as advances to and receivables from other organizations, employees and other individuals, as well as inventories held for resale.

Assets acquired by right are not included.

Accounts Receivable

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

Inventory for Resale

Inventory consists of conventional and synthetic oil in feeder and trunk pipelines. Inventories are stated at lower of cost or net realizable value.

Liabilities

Liabilities are recorded to the extent that they represent present obligations as a result of events and transactions occurring prior to the end of fiscal year. The settlement of liabilities will result in sacrifice of economic benefits in the future.

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 government services;
b) may be consumed in the normal course of operations; and
c) are not for sale in the normal course of operations.

Non-financial assets of the department are limited to tangible capital assets.

Tangible capital assets of the department are recorded at historical cost and amortized on a straight-line basis over the estimated useful lives of the assets. The threshold for capitalizing new systems development is $250,000 and the threshold for major systems enhancements is $100,000. The threshold for all other tangible capital assets is $5,000.

Amortization is only charged if the tangible capital asset is put into service.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (cont'd)

(b) **Basis of Financial Reporting (cont'd)**

Measurement Uncertainty
(in thousands)

Measurement uncertainty exists when there is a variance between the recognized or disclosed amount and another reasonably possible amount. Natural gas and by-products revenue recorded as $493,032, bitumen royalty recorded as $1,222,971, and crude oil royalty revenue recorded as $688,800 in these financial statements are subject to measurement uncertainty.

Natural gas and by-products revenue is calculated based on allowable costs incurred by the royalty payers and production volumes that are reported to the department by royalty payers. Industry may modify their royalty and gas cost allowance for non-statute barred years. These amounts could vary significantly from that which was initially reported. The department estimates what the costs, volumes and royalty rates for the fiscal year should be based on statistical analysis of industry data. Based on historical data, changes to natural gas and by-products revenues was $153,341.

For projects from which bitumen royalty is paid and the project has reached payout, the royalty rate used to determine the royalties is based on the average price of West Texas Intermediate crude oil in Canadian dollars for the calendar year. Royalty rates will start at 25% of net profits when oil is priced at fifty five dollars per barrel or less, and increase to a maximum of 40% of net profits when oil is priced at one hundred and twenty dollars or more. Payout is defined at the first date at which the cumulative revenue of a project first equals the cumulative cost of the project.

(c) **Change in Accounting Policy**

A net debt presentation (with reclassification of comparatives) has been adopted for the presentation of financial statements. Net Debt or Net Financial Assets is measured as the difference between the department's financial assets and liabilities.

The effect of this change results in changing the presentation of the Statement of Financial Position and adding an additional Statement of Change in Net Debt.

(d) **Future Accounting Changes**

In June 2015 the Public Sector Accounting Board issued these following accounting standards:

- **PS2200 Related Party Disclosures** and **PS3420 Inter-Entity Transactions (effective April 1, 2017)**
  PS 2200 defines a related party and establishes disclosures required for related party transactions; PS3240 establishes standards on how to account for and report transactions between public sector entities that comprise a government's reporting entity from both a provider and recipient perspective. Management is currently assessing the impact of these standards on the financial statements.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (cont'd)

(d) **Future Accounting Changes (cont'd)**

- **PS3210 Assets**, **PS3320 Contingent Assets**, and **PS3380 Contractual Rights (effective April 1, 2017)**
  PS3210 provides guidance for applying the definition of assets set out in FINANCIAL STATEMENT CONCEPTS, Section PS1000 establishes general disclosure standards for assets; PS3320 defines and establishes disclosure standards on contingent assets; PS3380 defines and establishes disclosure standards on contractual rights. Management is currently assessing the impact of these standards on the financial statements.

NOTE 3 PRIOR PERIOD RESTATEMENT

The Energy Utilities Board issued Guide 46 of the "Production Audit Handbook" in January 2003 with potential natural gas royalty implications. In fiscal 2005-2006, the department made an accounting estimate based on interpretation of the Guide. The reversal of this estimate was missed in the following fiscal year and this error has been carried into future fiscal years.

The correction of this error is being made in fiscal 2015-16 and is accounted for retrospectively by restating fiscal 2014-15 comparatives. The impacts are reductions to Accounts Receivable and Net Assets by $237 million.

NOTE 4 OTHER REVENUE

(in thousands)

	2016	2015 (Restated)
Disgorgement Payment and Monetary Penalty to TransAlta Corporation	$ 51,921	$ -
Settlements Related to the Land-Use Framework	25,891	-
Other Revenue	3,325	18,458
	$ 81,137	$ 18,458

<u>Disgorgement Payment and Monetary Penalty to TransAlta Corporation</u>
The disgorgement payment and the monetary penalty levied against TransAlta Corporation of $51,921 have been reflected in these financial statements in accordance with the provisions set out in AUC Decision 3110-D03-2015.

<u>Settlements Related to the Land-Use Framework</u>
All provisions for the settlements related to energy lease cancellation associated with the Land-Use Framework for the Lower Athabasca Regional Plan and the Urban Development Sub-Region were settled in Fiscal 2015-16. These land lease cancellations were made under section 8(1)(c) of the Mines and Minerals Act and the compensation amount as determined under the Mineral Rights Compensation Regulation. No right of review, recalculation, or appeal of the compensation amount is provided for under these legislations.

The estimated settlements were based upon the bonus bids, application fees, and the annual rental paid and/or expected to be paid by the lessees prior to the settlement. The development and abandonment costs were estimated by the Department based upon information provided by the lessees. Interest provisions were also made based on the projected settlement date of these claims as provided for in the Regulation. The settlements were reflected as a reduction of revenue in the years when the original estimates were made.

NOTE 4 OTHER REVENUE (cont'd)
(in thousands)

Upon submission of final documentation from the lessees, the actual settlements were $25,891 lower than booked. The effect of this change is a reduction to Liabilities and an increase in Other Revenues, in accordance the Government of Alberta's accounting treatment of an over accrual of prior year's expenditures.

NOTE 5 CASH AND CASH EQUIVALENTS

Cash consists of deposits in Canadian financial institutions which are managed by the Province of Alberta with the objective of providing competitive interest income to depositors 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.

NOTE 6 ACCOUNTS RECEIVABLE
(in thousands)

Accounts receivable royalties are secured by a claim against the mineral leases and are interest bearing in accordance with the applicable legislation.

	2016			2015 (Restated)
	Gross Amount	Allowance for Doubtful Accounts	Net Realizable Value	Net Realizable Value
Non-Royalty Receivables	$ 129,693	$ -	$ 129,693	$ 209,021
Bioenergy Grant Recoveries	9,026	6,015	3,011	112
Due from APMC	727	-	727	-
Alberta Energy Regulator	-	-	-	4,050
	$ 139,446	$ 6,015	$ 133,431	$ 213,183

NOTE 7 INVENTORY FOR RESALE

Inventory reported consists of crude oil inventory held for marketing by APMC. Inventory is calculated based on inventory volumes held in various revenue pools multiplied by average pricing.

NOTE 8 ACCOUNTS PAYABLE AND ACCRUED LIABILITIES
(in thousands)

	2016	2015 (Restated)
Trade	$ 188,977	$ 169,183
Overpayments of Royalties	158,656	417,622
Due to APMC	-	3,346
	$ 347,633	$ 590,151

NOTE 9 GAS ROYALTY DEPOSITS

The department 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 department does not pay interest on the deposits.

NOTE 10 TANGIBLE CAPITAL ASSETS

(in thousands)

	Equipment [1]	Computer Hardware and Software	Total
Estimated Useful Life	3-40 years	3-10 years	
Historical Cost [2]			
Beginning of Year	$ 27,791	$ 96,908	$ 124,699
Additions	79	1,834	1,913
Disposals, Including Write-downs	(13,168)	(3,251)	(16,419)
	$ 14,702	$ 95,491	$ 110,193
Accumulated Amortization			
Beginning of Year	$ 21,565	$ 72,499	$ 94,064
Amortization Expense	1,990	6,267	8,257
Effect of Disposals	(13,152)	(3,251)	(16,403)
	$ 10,403	$ 75,515	$ 85,918
Net Book Value at March 31, 2016	$ 4,299	$ 19,976	$ 24,275
Net Book Value at March 31, 2015	$ 6,226	$ 24,409	$ 30,635

[1] Equipment includes office equipment and furniture and other equipment.

[2] Historical cost includes work-in-progress at March 31, 2016 totaling $99 (2015 - $0) for computer software.

NOTE 11 CONTINGENT LIABILITIES

(in thousands)

The department is involved in legal matters where damages are being sought. These matters may give rise to contingent liabilities. Accruals have been made in specific instances where it is likely that losses will be incurred based on a reasonable estimate.

The department has been named in five claims (2015 restated - two), all with outcomes that are not determinable. Three claims have specified amounts of $7,158 (2015 one claim of $7,000) and two claims (2015 restated - one) has no specified amounts.

NOTE 11 CONTINGENT LIABILITIES (cont'd)

(in thousands)

The department has been jointly named with other entities in seven claims (2015 restated - six). Five of these claims have specified amounts totaling $14,350 (2015 restated – five claims totaling $14,350) and two claims (2015 restated - one) with no amounts specified.

Of the total specified claims, two claims totaling $10,007 (2015 - two claims totaling $10,007) are partially or fully covered by the Alberta Risk Management Fund.

The resolution of the indeterminable claim may result in a liability, if any, that may be significantly lower than the claimed amount.

NOTE 12 CONTRACTUAL OBLIGATIONS

(in thousands)

As at March 31, 2016, the department had contractual obligations totaling $799,886 (2015 - $1,058,907).

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

These amounts include obligations under long-term contracts with contract payment requirements for each of the next five years and thereafter are as follows:

	Grant Agreements	Service Contracts	Total
2017	$ 267,850	$ 20,888	$ 288,738
2018	69,400	287	69,687
2019	69,400	103	69,503
2020	49,600	5	49,605
2021	49,600	3	49,603
Thereafter	272,750	-	272,750
	$ 778,600	$ 21,286	$ 799,886

NOTE 13 TRUST FUNDS UNDER ADMINSTRATION

(in thousands)

The department administers the Oil and Gas Conservation Trust consisting of public money over which the Legislature has no power of appropriation. Because the Province has no equity in the fund and administers the fund for the purpose of various trusts, the fund is not included in the department's financial statements.

As at March 31, 2016, the funds in the Oil and Gas Conservation Trust are $4,594 (2015 - $4,463).

NOTE 14 BENEFIT PLANS

(in thousands)

The department participates in the multi-employer pension plans: Management Employees Pension Plan and Public Service Pension Plan and Supplementary Retirement Plan for Public Service Managers. The expense for these pension plans is equivalent to the annual contributions of $10,141 for the year ended March 31, 2016 (2015 - $10,150). Departments are not responsible for future funding of the plan deficit other than through contribution increases.

At December 31, 2015, the Management Employees Pension Plan reported a surplus of $299,051 (2014 - surplus of $75,805), the Public Service Pension Plan reported a deficiency of $133,188 (2014 deficiency - $803,299) and the Supplementary Retirement Plan for Public Service Managers reported a deficiency of $16,305 (2014 - deficiency of $17,203).

The department also participates in two multi-employer Long Term Disability Income Continuance Plans. At March 31, 2016, the Bargaining Unit Plan reported an actuarial surplus of $83,006 (2015 - surplus $86,888) and the Management, Opted Out and Excluded Plan an actuarial surplus of $29,246 (2015 - surplus $32,343). The expense for these two plans is limited to the employer's annual contributions for the year.

NOTE 15 ROYALTY REDUCTION PROGRAMS

(in thousands)

The department provides eleven oil and gas royalty reduction programs. The intent of these programs is to encourage industry to produce from wells which otherwise would not be economically productive. For the year ended March 31, 2016, the royalties received under these programs were reduced by $850,912 (2015 restated - $1,442,873).

NOTE 16 BITUMEN CONSERVATION

(in thousands)

In 2004-05 the Alberta Energy and Utilities (EUB) Board (now known as the AER) released its Bitumen Conservation Requirements decisions regarding the status of natural gas wells in the Wabiskaw-McMurray region of the Athabasca Oil Sands area. The decisions recommended the shut-in of Wabiskaw-McMurray natural gas totaling about 53.6 billions of cubic feet annually to protect about 25.5 billion barrels of potentially recoverable bitumen. The Natural Gas Royalty Regulations, 2002 was amended to provide a royalty mechanism that would allow the Minister of Energy to calculate a royalty adjustment each month for gas producers affected by the EUB decisions. The Natural Gas Royalty Regulations, 2002 was also amended to provide for the royalty adjustment to be recovered through additional royalty on the shut-in wells when they return to production through amendments to the provisions that deal with the calculation of the royalty share of gas. The amendments provide for an increase over and above the usual royalty rate, and extend to new wells that produce from the shut-in zone. The effect of these adjustments was to reduce natural gas and by-products revenue by $12,139 (2015 - $26,374).

NOTE 17 COMPARATIVE FIGURES

Certain 2015 figures have been reclassified to conform to 2016 presentation.

NOTE 18 APPROVAL OF FINANCIAL STATEMENTS

The financial statements were approved by the Senior Financial Officer and the Deputy Minister.

DEPARTMENT OF ENERGY **Schedule 1**

SCHEDULE TO FINANCIAL STATEMENTS

REVENUES

Year ended March 31, 2016

(in thousands)

	2016 Budget	2016 Actual	2015 Actual (Note 17)
Non-Renewable Resource Revenue (Note 15)			
Bitumen Royalty	$ 1,547,000	$ 1,222,971	$ 5,049,393
Crude Oil Royalty	536,000	688,800	2,244,745
Natural Gas and By-Products Royalty (Note 16)	343,000	493,032	989,160
Bonuses and Sales of Crown Leases	181,000	203,267	476,331
Rentals and Fees	145,000	167,382	172,489
Coal Royalty	15,000	13,668	15,755
	2,767,000	2,789,120	8,947,873
Freehold Mineral Rights Tax	87,000	79,395	171,831
Other Revenue (Note 4)	56,500	81,137	18,458
Total Revenue	$ 2,910,500	$ 2,949,652	$ 9,138,162

DEPARTMENT OF ENERGY **Schedule 2**

SCHEDULE TO FINANCIAL STATEMENTS

EXPENSES - DIRECTLY INCURRED

Year ended March 31, 2016

(in thousands)

	2016 Budget	2016 Actual	2015 Actual (Note 17)
Grants	$ 379,768	$ 230,902	$ 142,343
Salaries, Wages and Employee Benefits	81,706	79,339	84,017
Supplies and Services	201,664	98,586	196,665
Amortization of Tangible Capital Assets (Note 10)	6,588	8,257	7,771
Settlements Related to the Land-Use Framework	-	-	4,123
Other	-	64	67
Total Expenses before Recoveries	669,726	417,148	434,986
Less Recovery from Support Service Arrangements with Related Parties [1]	-	(566)	(619)
	$ 669,726	$ 416,582	$ 434,367

[1] The department provides financial services to the Department of Environment and Parks. Costs incurred by the department for these services are recovered from the Department of Environment and Parks.

DEPARTMENT OF ENERGY **Schedule 3**

SCHEDULE TO FINANCIAL STATEMENTS

LAPSE/ENCUMBRANCE

Year ended March 31, 2016

(in thousands)

	Voted Estimate [1]	Supplementary Estimate [2]	Adjusted Voted Estimate	Voted Actuals [3]	Unexpended (Over Expended)
Program - Operational					
Program - Ministry Support Services					
1.1 Minister's Office	$ 703	$ -	$ 703	$ 1,075	$ (372)
1.2 Associate Minister's Office	-	-	-	-	-
1.3 Deputy Minister's Office	485	-	485	496	(11)
1.4 Communications	1,601	-	1,601	1,308	293
1.5 Corporate Service	4,602	-	4,602	4,581	21
	7,391	-	7,391	7,460	(69)
Program - Resource Development and Management					
2.1 Revenue Collection	45,203	-	45,203	41,027	4,176
2.2 Resource Development	42,189	-	42,189	52,187	(9,998)
	87,392	-	87,392	93,214	(5,822)
Program - Bioenergy Initiatives					
3 Bioenergy Initiatives	92,000	-	92,000	70,498	21,502
	92,000	-	92,000	70,498	21,502
Program - Cost of Selling Oil					
4 Cost of Selling Oil	184,616	-	184,616	77,168	107,448
	184,616	-	184,616	77,168	107,448
Total	$ 371,399	$ -	$ 371,399	$ 248,340	$ 123,059
Lapse/(Encumbrance)					$ 123,059
Program - Capital					
Program - Ministry Support Services	$ -	$ -	$ -	$ -	$ -
Program - Resource Development and Management	5,999	-	5,999	1,913	4,086
Total	$ 5,999	$ -	$ 5,999	$ 1,913	$ 4,086
Lapse/(Encumbrance)					$ 4,086
Financial Transactions					
Settlements Related to the Land-Use Framework	$ 86,156	$ -	86,156	59,728	$ 26,428
Total	$ 86,156	$ -	$ 86,156	$ 59,728	$ 26,428
Lapse/(Encumbrance)					$ 26,428

(1) As per "Operational Vote by Program", "Voted Capital Vote by Program" and "Financial Transaction Vote by Program" page of 2015-16 Government Estimates.

(2) There was no Supplementary Estimate during the year.

(3) Actuals exclude non-voted amounts such as statutory programs, amortization and valuation adjustments.

DEPARTMENT OF ENERGY **Schedule 4**

SCHEDULE FOR FINANCIAL STATEMENTS

SALARY AND BENEFITS DISCLOSURE

Year ended March 31, 2016

(in thousands)

	2016				2015
	Base Salary (1)	Other Cash Benefits (2)	Other Non-cash Benefits (3)	Total	Total
Deputy Minister (4)	$ 286	$ -	$ 71	$ 357	$ 341
Executives					
Assistant Deputy Minister - Oil Sands	193	-	51	244	228
Assistant Deputy Minister - Strategy & Market Access	200	-	53	253	245
Assistant Deputy Minister - Ministry Support Services	193	-	50	243	228
Assistant Deputy Minister - Electricity & Sustainable Energy	198	-	52	250	229
Assistant Deputy Minister - Policy Management Office (5)	50	-	13	63	123
Assistant Deputy Minister - Resource Development Policy (6)	100	-	26	126	219
Assistant Deputy Minister - Resource Revenue & Operations (7)	62	21	2	85	228
Assistant Deputy Minister - Resource Revenue & Operations/Strategic Initiatives (8)	200	-	54	254	246

Total salary and benefits relating to a position are disclosed.

(1) Base salary includes regular salary and earning such as acting pay.

(2) Other cash benefits include vacation payouts and lump sum payments. There were no bonuses paid in 2016.

(3) Other non-cash benefits include government's share of all employee benefits and contributions or payments made on behalf of employees including pension, supplementary retirement plans, health care, dental coverage, group life insurance, short and long term disability plans, car allowances, health spending account expense, and professional memberships and tuition fees.

(4) Automobile provided, no dollar amount included in other non-cash benefits.

(5) The incumbent's services are shared with the Department of Environment & Parks which contributes its own share of the cost of salary and benefits. Only 50% of the full salary and benefits are disclosed in this Schedule. In February 2016, this Program was transferred to Environment and Parks.

(6) This position was occupied by the same individual who is also the Assistant Deputy Minister - Policy Management Office until the program was transferred in February 2016.

(7) This position was occupied by one individual until July 17, 2015. The Other Cash Benefits reflect the payout of unused vacation.

(8) This position combined the portfolios for Assistant Deputy Minister - Resource Revenue & Operations and the ADM - Strategic Initiatives effective July 20, 2015.

DEPARTMENT OF ENERGY **Schedule 5**

SCHEDULE TO FINANCIAL STATEMENTS

RELATED PARTY TRANSACTIONS

Year ended March 31, 2016
(in thousands)

Related parties are those entities consolidated or accounted for on the modified equity basis in the Government of Alberta's financial statements. Related parties also include key management personnel in the Department.

The department and its employees paid or collected certain taxes and fees set by regulation for premiums, licenses and other charges. These amounts were incurred in the normal course of business, reflect charges applicable to all users, and have been excluded from this Schedule.

The department had the following transactions with related parties recorded on the Statement of Operations and the Statement of Financial Position at the amount of consideration agreed upon between the related parties:

	Entities in the Ministry		Other Entities	
	2016	**2015**	**2016**	**2015**
Accounts Receivable	$ 27,767	$ 38,911	$ 41	$ -
Accounts Payable	$ -	$ 3,346	$ 309	$ -
Expenses - Directly Incurred				
Grants	-	19,800	76	-
Other services	75	145	2,408	3,203
	$ 75	$ 19,945	$ 2,484	$ 3,203
Contractual Obligations	$ -	$ -	$ -	$ -

The above transactions do not include support service arrangement transactions disclosed in Schedule 2.

The department also had the following transactions with related parties for which no consideration was exchanged. The amounts for these related party transactions are estimated based on the costs incurred by the service provider to provide the service. These amounts are not recorded in the financial statements and are disclosed in Schedule 6.

	Entities in the Ministry		Other Entities	
	2016	**2015**	**2016**	**2015**
Expenses - Incurred by Others				
Accommodation	$ -	$ -	$ 6,478	$ 6,284
Legal	-	-	5,048	4,103
Business Services	-	-	2,745	4,082
	$ -	$ -	$ 14,271	$ 14,469

DEPARTMENT OF ENERGY **Schedule 6**

SCHEDULE TO FINANCIAL STATEMENTS

ALLOCATED COSTS

Year ended March 31, 2016

(in thousands)

	2016					2015
		Expenses -Incurred by Others				(Note 17)
Program	**Expenses [1]**	**Accommodation Costs [2]**	**Legal Services [3]**	**Business Services [4]**	**Total Expenses**	**Total Expenses**
Ministry Support Services	$ 7,460	$ 530	$ 1,935	$ -	$ 9,925	$ 9,727
Resource Development and Management	101,583	5,798	3,113	2,789	113,283	114,139
Bioenergy Initiatives	70,498	84	-	-	70,582	70,318
Cost of Selling Oil	77,168	-	-	-	77,168	176,426
Carbon Capture and Storage	159,873	65	-	-	159,938	54,001
Settlements Related to the Land-Use Framework	-	-	-	-	-	4,123
Energy Regulation	-	-	-	-	-	19,800
	$ 416,582	$ 6,477	$ 5,048	$ 2,789	$ 430,896	$ 448,534

(1) Expenses - Directly Incurred as per Statement of Operations.

(2) Costs shown for Accommodation are allocated by budgeted Full-Time Equivalent Employment.

(3) Costs shown for Legal Services are allocated by estimated costs incurred by each program.

(4) Costs shown for Business Service include charges for information technology support, vehicles, internal audit services and other services are allocated by costs in certain programs.

ALBERTA ENERGY REGULATOR

FINANCIAL STATEMENTS
For the year ended March 31, 2016

Independent Auditor's Report

To the Board of Directors of the Alberta Energy Regulator

Report on the Financial Statements

I have audited the accompanying financial statements of the Alberta Energy Regulator, which comprise the statement of financial position as at March 31, 2016, and the statements of operations, change in net debt and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these 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 financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

My responsibility is to express an opinion on these financial statements based on my audit. I conducted my audit in accordance with Canadian generally accepted auditing standards. Those standards require that I comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements 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 entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my audit opinion.

Opinion

In my opinion, the financial statements present fairly, in all material respects, the financial position of the Alberta Energy Regulator as at March 31, 2016, and the results of its operations, its remeasurement gains and losses, its changes in net debt, and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Original signed by Merwan N. Saher, FCPA, FCA
Auditor General

May 11, 2016

Edmonton, Alberta

ALBERTA ENERGY REGULATOR
STATEMENT OF OPERATIONS
Year Ended March 31
(in thousands)

	2016		2015
	Budget (Note 3)	Actual	Actual
Revenues			
Industry levies and assessments	$ 270,093	$ 270,335	$ 258,278
Provincial grant		-	19,800
Information, services and fees	6,859	6,867	8,260
Investment	1,300	1,278	1,654
	278,252	278,480	287,992
Expenses			
Energy regulation (Schedule 1)	253,252	249,113	256,827
Orphan abandonment (Note 4)	30,500	31,111	15,760
	283,752	280,224	272,587
Annual operating (deficit) surplus	(5,500)	(1,744)	15,405
Accumulated operating surplus at beginning of year	63,855	63,855	48,450
Accumulated operating surplus at end of year	$ 58,355	$ 62,111	$ 63,855

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

ALBERTA ENERGY REGULATOR
STATEMENT OF FINANCIAL POSITION
As at March 31
(in thousands)

	2016	2015
Financial assets		
Cash and cash equivalents (Note 5)	$ 24,851	$ 54,040
Security deposits (Note 7)	138,125	122,835
Accounts receivable	18,149	12,245
	181,125	189,120
Liabilities		
Accounts payable and accrued liabilities	16,643	33,511
Grant payable to Orphan Well Association	15,093	15,055
Security deposits (Note 7)	138,125	122,835
Deferred revenue (Note 9)	1,604	2,056
Deferred lease incentives (Note 10)	22,264	23,023
Pension obligations (Note 12)	692	2,349
	194,421	198,829
Net debt	(13,296)	(9,709)
Non-financial assets		
Tangible capital assets (Note 13)	64,430	63,211
Prepaid expenses and other assets	10,977	10,353
	75,407	73,564
Accumulated operating surplus (Note 14)	$ 62,111	$ 63,855

Contractual obligations (Note 16)

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

ALBERTA ENERGY REGULATOR
STATEMENT OF CHANGE IN NET DEBT
Year Ended March 31
(in thousands)

	2016		2015
	Budget (Note 3)	Actual	Actual
Annual operating (deficit) surplus	$ (5,500)	$ (1,744)	$ 15,405
Acquisition of tangible capital assets (Note 13)	(9,000)	(14,196)	(20,854)
Amortization of tangible capital assets (Note 13)	11,500	12,645	11,836
Loss on disposal and write-down of tangible capital assets		332	779
Increase in prepaid expenses and other assets		(624)	(693)
(Increase) decrease in net debt	(3,000)	(3,587)	6,473
Net debt at beginning of year	(9,709)	(9,709)	(16,182)
Net debt at end of year	$ (12,709)	$ (13,296)	$ (9,709)

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

ALBERTA ENERGY REGULATOR
STATEMENT OF CASH FLOWS
Year Ended March 31
(in thousands)

	2016	2015
Operating transactions		
Annual operating (deficit) surplus	$ (1,744)	$ 15,405
Non-cash items included in net operating results		
Amortization of tangible capital assets (Note 13)	12,645	11,836
Loss on disposal and write-down of tangible capital assets	332	779
Change in pension obligations	(1,657)	(942)
Amortization of deferred lease incentives (Note 10)	(1,522)	(1,430)
	8,054	25,648
(Increase) in accounts receivable	(5,904)	(8,353)
(Increase) in prepaid expenses and other assets	(624)	(693)
(Decrease) increase in accounts payable and accrued liabilities	(16,868)	11,929
Increase in grant payable to Orphan Well Association	38	4,305
(Decrease) in deferred revenue	(452)	(915)
Additions to deferred lease incentives (Note 10)	763	918
Cash (used) provided by operating transactions	(14,993)	32,839
Capital transactions		
Acquisition of tangible capital assets (Note 13)	(14,196)	(20,854)
Cash applied to capital transactions	(14,196)	(20,854)
(Decrease) increase in cash and cash equivalents	(29,189)	11,985
Cash and cash equivalents at beginning of year	54,040	42,055
Cash and cash equivalents at end of year	$ 24,851	$ 54,040

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

ALBERTA ENERGY REGULATOR
NOTES TO THE FINANCIAL STATEMENTS
March 31, 2016
(in thousands)

Note 1 Authority and purpose

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

Note 2 Summary of significant accounting policies and reporting practices

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

(a) Revenues

All revenues are reported on the accrual basis of accounting. Cash received for which services have not been provided by year end is recorded as deferred revenue.

Government transfers

Transfers from the Government of Alberta are referred to as provincial grants.

Provincial grants, without terms for the use of the transfer, are recorded as revenue when the transfer is authorized and the AER is eligible to receive the funds.

(b) Expenses

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

(c) Valuation of financial assets and liabilities

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

Financial Statement Component	Measurement
Cash and cash equivalents	Cost
Accounts receivable	Lower of cost or net recoverable value
Security deposits	Cost
Accounts payable and accrued liabilities	Cost
Grant payable to the Orphan Well Association	Cost

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

(d) 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 of the AER are limited to cash and cash equivalents, security deposits and financial claims on other organizations.

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

(e) Liabilities

Liabilities are present obligations of the AER to others arising from past transactions or events, the settlement of which is expected to result in the future sacrifice of economic benefits.

Pension

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

The expected return on plan assets is determined using market values of plan assets.

Actuarial gains and losses are amortized over the average remaining service period of the active employees, which is 9.6 years.

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

Defined contribution plan accounting is applied to the Government of Alberta multi-employer defined benefit pension plans as the AER has insufficient information to apply defined benefit plan accounting. The AER is not responsible for future funding of the plan deficit other than through contribution increases.

Deferred lease incentives

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

Liability for contaminated sites

Contaminated sites are a result of contamination of a chemical, organic or radioactive material or live organism that exceeds an environmental standard, being introduced into soil, water or sediment. The liability is recorded net of any expected recoveries. A liability for remediation of contaminated sites is recognized when all of the following criteria are met:

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

(f) Non-financial assets

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

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

Non-financial assets of the AER are limited to tangible capital assets and prepaid expenses and other assets.

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

(f) Non-financial assets (continued)

Tangible capital assets

Tangible capital assets are recorded at historical cost, which includes amounts that are directly related to the acquisition, design, construction, development, improvement or betterment of the assets and are amortized over their estimated useful lives using the following methods:

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

Amortization is only charged if the tangible capital asset is put into service.

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

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

(g) 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 tangible capital assets are based on estimates of the useful life of the related assets. Accrued defined benefit obligations are subject to measurement uncertainty due to the use of actuarial assumptions. The resulting estimates are within reasonable limits of materiality and are in accordance with the AER's significant accounting policies.

(h) Change in accounting policy

Adoption of net debt presentation

The net debt presentation with reclassification of comparatives has been adopted for the presentation of financial statements. Net debt or net financial assets is measured as the difference between the AER's financial assets and liabilities.

The effect of this change results in changing the presentation of the Statement of Financial Position and adding the Statement of Change in Net Debt.

(i) Future accounting changes

In March 2015 the Public Sector Accounting Board (PSAB) issued the following accounting standards:

PS 2200 Related Party Disclosure and PS 3420 Inter-entity Transactions (effective April 1, 2017)

PS 2200 defines a related party and establishes disclosures required for related party transactions; PS 3420 establishes guidance on how to account for and report transactions between public sector entities that comprise a government's reporting entity from both a provider and recipient perspective. Management is currently assessing the impact of these standards on the financial statements.

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

(i) Future accounting changes (continued)

In June 2015 the PSAB issued the following accounting standards:

PS 3210 Assets, PS 3320 Contingent Assets and PS 3380 Contractual Rights (effective April 1, 2017)
PS 3210 provides guidance for applying the definition of assets set out in Financial Statement Concepts, PS 1000, and establishes general disclosure standards for assets; PS 3320 defines and establishes disclosure standards on contingent assets; PS 3380 defines and establishes disclosure standards on contractual rights. Management is currently assessing the impact of these standards on the financial statements.

PS 3430 Restructuring Transactions (effective April 1, 2018)
This standard provides guidance on how to account for and report restructuring transactions by both transferors and recipients of assets and/or liabilities, together with related programs or operating responsibilities. Management is currently assessing the impact of these standards on the financial statements.

Note 3 Budget

The Budget is based on the AER Business Plan for the year ended March 31, 2016. The Budget has been approved by the Government of Alberta.

Note 4 Orphan abandonment

The AER has delegated the authority to manage the abandonment and reclamation of wells, facilities and pipelines that are licensed to defunct licensees to the Alberta Oil and Gas Orphan Abandonment and Reclamation Association (Orphan Well Association). The AER grants all of its orphan abandonment revenues (levy and application fees) to the Orphan Well Association. During the year ended March 31, 2016, the AER collected $30,167 (2015 - $15,000) in levies and $944 (2015 - $760) in application fees.

Note 5 Cash and cash equivalents

Cash and cash equivalents are held in an account with a Canadian chartered bank and earn interest calculated based on the average monthly cash balance. The funds are available to be withdrawn upon request. During the year ended March 31, 2016, the AER earned interest at the rate of 1.1% (2015 - 1.3%).

Note 6 Financial instruments

The AER has the following financial instruments: accounts receivable, accounts payable and accrued liabilities, grant payable to the Orphan Well Association and security deposits.

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

(a) Liquidity risk

Liquidity risk is the risk that the AER will encounter difficulty in meeting obligations associated with financial liabilities. The AER does not consider this to be a significant risk as the AER collects funding at the beginning of the year to meet all obligations that arise during the year. In addition, the available credit facility provides financial flexibility to allow the AER to meet its obligations if funding cannot be collected on a timely basis.

(b) Credit risk

The AER is exposed to credit risk from potential non-payment of accounts receivable. As at March 31, 2016, the amount of financial assets that were past due was not significant and there were no material uncollectible receivable balances.

(in thousands)

Note 7 Security deposits

The AER collects financial security under a number of different programs to protect the public from paying costs associated with abandonment and reclamation of upstream wells, facilities, pipelines, mines, mine sites and oilfield waste management facilities. The security deposits are held on behalf of licensees. The AER administers the programs in accordance with specified acts and regulations and does not have any financial risk associated with security collected. At March 31, 2016, the AER held $138,125 (2015 - $122,835) in cash and an additional $1,528,339 (2015 - $1,707,241) in letters of credit. Security, along with any interest earned, will be returned to the depositors upon meeting specified refund criteria.

Note 8 Revolving line of credit

During 2016, the AER had an unsecured $50,000 revolving line of credit. Amounts borrowed can only be applied to general corporate purposes and exclude the funding of operating deficits and/or capital expenditures. Bank advances on the line of credit are payable on demand and bear interest at prime less 0.5%. As at March 31, 2016, the outstanding balance for the revolving line of credit was $nil (2015 -$nil).

Note 9 Deferred revenue

	2016	2015
Balance at beginning of year	$ 2,056	$ 2,971
Received during year	395	347
Less amounts recognized as revenue	(847)	(1,262)
Balance at end of year	$ 1,604	$ 2,056

Note 10 Deferred lease incentives

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

	2016			2015
	Leasehold improvement costs	Reduced rent benefits and rent-free periods	Total	Total
Balance at beginning of year	$ 18,331	$ 4,692	$ 23,023	$ 23,535
Additions during the year	763	-	763	918
Amortization	(1,195)	(327)	(1,522)	(1,430)
Balance at end of year	$ 17,899	$ 4,365	$ 22,264	$ 23,023

Note 11 Liability for contaminated sites

As at March 31, 2016, the AER is not responsible, nor has it accepted responsibility, for performing remediation work at contaminated sites. As at March 31, 2016, the AER's liability for contaminated sites was $nil (2015 - $nil).

Note 12 Pension

The AER participates in the Government of Alberta's multi-employer pension plans: Management Employees Pension Plan, Public Service Pension Plan and Supplementary Retirement Plan for Public Service Managers. For the year ended March 31, 2016, the expense for these pension plans is equal to the contribution of $18,026 (2015 - $17,325). Pension expense recorded is comprised of employer contributions to the plans that are required for its employees during the year, which are calculated based on actuarially determined amounts that are expected to provide the plans' future benefits.

(in thousands)

Note 12 Pension (continued)

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

The effective date of the most recent actuarial funding valuation for SEPP was December 31, 2014. The accrued benefit obligation as at March 31, 2016 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, 2017.

Pension plan assets are valued at market values. During the year ended March 31, 2016 the weighted average actual return on plan assets was -3.4% (11.7% in 2015).

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

Accrued benefit obligations	March 31, 2016	March 31, 2015
Discount rate	4.7%	4.9%
Rate of compensation increase	0% for 2 years, 3.5% thereafter	0% for 1 year, 3.5% thereafter
Long-term inflation rate	2.0%	2.0%

Pension benefit costs for the year	2016	2015
Discount rate	4.9%	5.3%
Expected rate of return on plan assets	4.9%	5.3%
Rate of compensation increase	0% for 1 year, 3.5% thereafter	3.8%

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

	March 31, 2016	March 31, 2015
Market value of plan assets	$ 47,853	$ 45,087
Accrued benefit obligations	54,639	49,510
Plan (deficit)	(6,786)	(4,423)
Unamortized actuarial loss	6,094	2,074
Pension obligations	$ (692)	$ (2,349)

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

	2016	2015
Current period benefit cost	$ 4,375	$ 3,625
Interest cost	2,573	2,394
Expected return on plan assets	(2,330)	(2,110)
Amortization of actuarial losses	436	396
	$ 5,054	$ 4,305

(in thousands)

Note 12 Pension (continued)

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

	2016	2015
AER contribution	$ 6,711	$ 5,247
Employees' contribution	861	731
Benefits paid	3,216	3,350

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

	March 31, 2016	March 31, 2015
Equity securities	47.9%	49.9%
Debt securities	37.7%	38.4%
Other	14.4%	11.7%
	100.0%	100.0%

Note 13 Tangible capital assets

	2016					2015
	Land	**Leasehold improvements**	**Furniture and equipment**	**Computer hardware and software**	**Total**	**Total**
Estimated useful life	Indefinite	Term of the lease	5-12 years	4-5 years		
Historical cost						
Beginning of year	$ 282	$ 36,055	$ 16,154	$ 123,999	$ 176,490	$ 157,359
Additions	-	2,870	759	10,567	14,196	20,854
Disposals, including write-downs	-	(218)	(1,664)	(7,698)	(9,580)	(1,723)
	282	38,707	15,249	126,868	181,106	176,490
Accumulated amortization						
Beginning of year	$ -	$ 7,740	$ 9,227	$ 96,312	$ 113,279	$ 102,387
Amortization expense	-	2,266	1,066	9,313	12,645	11,836
Disposals, including write-downs	-	(86)	(1,489)	(7,673)	(9,248)	(944)
	-	9,920	8,804	97,952	116,676	113,279
Net book value at March 31, 2016	$ 282	$ 28,787	$ 6,445	$ 28,916	$ 64,430	
Net book value at March 31, 2015	$ 282	$ 28,315	$ 6,927	$ 27,687		$ 63,211

Historical cost includes work-in-progress at March 31, 2016 totaling $3,767 (March 31, 2015 - $454) comprised of: computer hardware and software $3,767 (March 31, 2015 - $321) and leasehold improvements $nil (March 31, 2015 - $133).

(in thousands)

Note 14 Accumulated operating surplus

The accumulated operating surplus of the AER is calculated as the sum of the net debt of the AER and its non-financial assets. The accumulated operating surplus represents the net assets of the AER. Accumulated operating surplus is comprised of the following:

	2016			2015
	Investments in tangible capital assets [(a)]	Unrestricted net assets	Accumulated operating surplus	Accumulated operating surplus
Balance at beginning of year	$ 44,880	$ 18,975	$ 63,855	$ 48,450
Annual operating (deficit) surplus	-	(1,744)	(1,744)	15,405
Net investment in capital assets	1,651	(1,651)	-	-
Balance at end of year	$ 46,531	$ 15,580	$ 62,111	$ 63,855

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

Note 15 Contingent liabilities

The AER, in the conduct of its normal activities, is a defendant in a number of legal proceedings. While the ultimate outcome and liability of these proceedings cannot be reasonably determined at this time, the AER believes that any settlement will not have a material adverse effect on the financial position or the results of operations of the AER. Based on legal advice, management has concluded that none of the claims meet the criteria for recording an accrued liability under PSAS.

Note 16 Contractual obligations

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

Estimated payment requirements for obligations under operating leases and contracts for each of the next five years and thereafter are as follows:

2017	$ 25,352
2018	20,160
2019	16,304
2020	12,506
2021	12,296
Thereafter	109,521
	$ 196,139

(in thousands)

Note 17 Related party transactions

Related parties are those entities consolidated or accounted for on the modified equity basis in the Province of Alberta's financial statements.

The AER had the following transactions with related parties recorded in the Statement of Operations and the Statement of Financial Position at the amount of consideration agreed upon between the related parties:

	Entities in the Ministry		Other entities	
	2016	**2015**	**2016**	**2015**
Revenues				
Provincial grant	$ -	$ 19,875	$ -	$ -
Information, services and fees	153	150	176	136
	$ 153	$ 20,025	$ 176	$ 136

	Entities in the Ministry		Other entities	
	2016	**2015**	**2016**	**2015**
Expenses				
Computer services	$ 2,124	$ 2,122	$ 1,714	$ 1,167
Buildings	-	-	846	600
Administrative	-	-	1,143	933
Consulting services	-	82	290	321
	$ 2,124	$ 2,204	$ 3,993	$ 3,021
Receivable from	$ 91	$ 10	$ 6	$ 4
Payable to	$ -	$ 4,460	$ 588	$ 669

Note 18 Comparative figures

Certain 2015 figures have been reclassified to conform to the 2016 presentation.

Note 19 Approval of financial statements

These financial statements were approved by the AER Board of Directors on May 11, 2016.

ALBERTA ENERGY REGULATOR **Schedule 1**

SCHEDULE TO THE FINANCIAL STATEMENTS

Energy Regulation Expenses

Year Ended March 31, 2016

(in thousands)

	2016	2015
Salaries, wages and employee benefits	$ 180,705	$ 178,148
Computer services	15,719	15,912
Buildings	15,198	18,016
Consulting services	13,692	19,990
Amortization of tangible capital assets	12,645	11,836
Travel and transportation	4,832	5,582
Administrative	4,373	4,133
Equipment rent and maintenance	936	1,173
Abandonment and enforcement	681	1,258
Loss on disposal and write-down of tangible capital assets	332	779
	$ 249,113	$ 256,827

ALBERTA ENERGY REGULATOR **Schedule 2**

SCHEDULE TO THE FINANCIAL STATEMENTS

Salaries and Benefits Disclosure

Year Ended March 31, 2016

(in thousands)

Position	2016 Base salary [(a)]	2016 Other cash benefits[(b)]	2016 Other non-cash benefits [(c)]	2016 Total [(d)]	2015 Total
Board of Directors					
Chairman	$ 269	$ -	$ 7	$ 276	$ 291
Board Director	114	-	6	120	119
Board Director	117	-	1	118	117
Board Director	107	-	10	117	129
Board Director	105	-	1	106	108
Board Director[(e)]	72	-	5	77	-
Board Director[(f)]	60	-	7	67	127
Board Director[(g)]	24	-	4	28	131
Board Director[(h)]	-	-	-	-	29
Executives					
President and Chief Executive Officer [(i)]	529	48	148	725	710
Chief Hearing Commissioner[(j)]	210	17	60	287	261
Executive Vice-President, Corporate Services	275	90	75	440	411
Executive Vice-President and General Counsel [(k)]	275	90	88	453	418
Executive Vice-President, Operations[(k)]	317	99	108	524	449
Executive Vice-President, Stakeholder & Government Relations	275	99	77	451	432
Executive Vice-President, Strategy & Regulatory[(k)]	275	73	38	386	414

(a) Includes retainers and per diems for Board Directors. Members of the Board of Directors do not participate in the AER's pension plans. Includes pensionable base pay for Executives.

(b) Payments in lieu of vacation and health benefits, vehicle allowances, and short term incentive payments for Executive Vice-Presidents.

(c) Contributions to all benefits as applicable including employer's share of Employment Insurance, Canada Pension Plan, Alberta and AER pension plans, health benefits or payments made for professional memberships and tuition fees.

(d) Salaries and benefits for the Board of Directors are presented in descending order.

(e) The incumbent held the position effective August 1, 2015.

(f) The incumbent left the position effective September 30, 2015.

(g) The incumbent left the position effective June 16, 2015.

(h) The incumbent left the position effective June 26, 2014.

(i) Automobiles provided, no dollar amount included in other non-cash benefits. During 2016, a relocation expense, related to home equity loss due to a required transfer of location, was paid in the amount of $127. Relocation expenses are a normal business expense and are not considered to be compensation.

(j) The position was held by two individuals in 2015.

SCHEDULE TO THE FINANCIAL STATEMENTS

Salaries and Benefits Disclosure

Year Ended March 31, 2016

(in thousands)

(k) Under the terms of the AER's defined benefit SEPP and two supplementary retirement plans (SRP), employees may receive supplemental retirement payments. Retirement arrangement costs as detailed below are not cash payments in the period but are the period expense for rights to future compensation. Costs shown reflect the total estimated cost to provide annual pension income over an actuarially determined post-employment period. The SEPP and SRP provide future pension benefits to participants based on years of service and remuneration. The cost of these benefits is actuarially determined using the projected benefit method pro-rated on service, a market interest rate, and management's best estimate of expected costs and the period of benefit coverage. Net actuarial gains and losses of the benefit obligations are amortized over the average remaining service life of the employee group. Current service cost is the actuarial present value of the benefits earned in the fiscal year. Prior service and other costs include amortization of past service costs, amortization of actuarial gains and losses, and interest accruing on the actuarial liability. The costs detailed below are only for those employees included in Schedule 2 who participate in the SEPP and SRP maintained by the AER to compensate senior staff who do not participate in the government management pension plans.

	2016			2015
Position	**Current service cost**	**Prior service and other costs**	**Total**	**Total**
Executive Vice-President and General Counsel	$ 39	$ 8	$ 47	$ 42
Executive Vice-President, Operations	54	2	56	52
Executive Vice-President, Strategy & Regulatory	5	22	27	40

Position	**Accrued obligation April 1, 2015**	**Changes in accrued obligation**	**Accrued obligation March 31, 2016**	**2015**
Executive Vice-President and General Counsel	$ 403	$ 72	$ 475	$ 403
Executive Vice-President, Operations	125	79	204	125
Executive Vice-President, Strategy & Regulatory	1,108	67	1,175	1,108

ALBERTA ENERGY REGULATOR **Schedule 3**

SCHEDULE TO THE FINANCIAL STATEMENTS

Actual Results Compared with Budget

Year Ended March 31, 2016

(in thousands)

	2016	
	Budget (Note 3)	**Actual**
Revenues		
Industry levies and assessments	$ 270,093	$ 270,335
Provincial grant		-
Information, services and fees	6,859	6,867
Investment	1,300	1,278
	278,252	278,480
Expenses		
Energy regulation	253,252	249,113
Orphan abandonment	30,500	31,111
	283,752	280,224
Annual operating (deficit)	(5,500)	(1,744)
Capital		
Capital investment	9,000	14,196
Less: Amortization	(11,500)	(12,645)
Loss on disposal and write-down of tangible capital assets		(332)
Net capital investment	(2,500)	1,219
	$ (3,000)	$ (2,963)

ALBERTA UTILITIES COMMISSION

FINANCIAL STATEMENTS
For the year ended March 31, 2016

Independent Auditor's Report

To the Members of the Alberta Utilities Commission

Report on the Financial Statements

I have audited the accompanying financial statements of the Alberta Utilities Commission, which comprise the statement of financial position as at March 31, 2016, and the statements of operations, change in net financial assets and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these 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 financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

My responsibility is to express an opinion on these financial statements based on my audit. I conducted my audit in accordance with Canadian generally accepted auditing standards. Those standards require that I comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements 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 entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my audit opinion.

Opinion

In my opinion, the financial statements present fairly, in all material respects, the financial position of the Alberta Utilities Commission as at March 31, 2016, and the results of its operations, its remeasurement gains and losses, its changes in net financial assets, and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Original signed by Merwan N. Saher, FCPA, FCA
Auditor General

May 12, 2016

Edmonton, Alberta

ALBERTA UTILITIES COMMISSION
STATEMENT OF OPERATIONS
Year Ended March 31, 2016

	2016		2015
	Budget (Schedule 3)	Actual	Actual
	---(in thousands)---		
Revenues			
Administration fees	$ 35,740	$ 32,855	$ 33,782
Investment income	300	172	240
Professional services	100	48	92
	36,140	33,075	34,114
Expenses			
Utility regulation (Schedule 1)	36,940	33,371	33,810
Annual operating (deficit) surplus	(800)	(296)	304
Accumulated surplus, beginning of year	16,278	16,278	15,974
Accumulated surplus, end of year	**$ 15,478**	**$ 15,982**	**$ 16,278**

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

ALBERTA UTILITIES COMMISSION
STATEMENT OF FINANCIAL POSITION
As at March 31, 2016

	2016	2015
	(in thousands)	
Financial Assets		
Cash and cash equivalents (Note 4)	$ 11,873	$ 11,745
Accounts receivable	300	174
	12,173	11,919
Liabilities		
Accounts payable and accrued liabilities	3,071	3,268
Accrued pension liability (Note 6)	765	765
Deferred lease incentive	59	40
	3,895	4,073
Net Financial Assets	8,278	7,846
Non-Financial Assets		
Capital assets (Note 7)	6,349	7,256
Prepaid expenses	1,355	1,176
	7,704	8,432
Net Assets		
Accumulated surplus (Note 8)	$ 15,982	$ 16,278

Contractual obligations (Note 9)

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

ALBERTA UTILITIES COMMISSION

STATEMENT OF CHANGE IN NET FINANCIAL ASSETS

Year Ended March 31, 2016

	2016		2015
	Budget (Schedule 3)	Actual	Actual
	----------(in thousands)----------		
Annual operating (deficit) surplus	$ (800)	$ (296)	$ 304
Acquisition of capital assets	(1,000)	(746)	(1,042)
Amortization of capital assets	1,800	1,615	1,428
Loss on disposal of capital assets		36	1
Proceeds on disposal of capital assets		2	-
Change in prepaid expenses		(179)	16
Increase in net financial assets in the year	-	432	707
Net financial assets, beginning of year	7,846	7,846	7,139
Net financial assets, end of year	**$ 7,846**	**$ 8,278**	**$ 7,846**

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

ALBERTA UTILITIES COMMISSION
STATEMENT OF CASH FLOWS
Year Ended March 31, 2016

	2016	2015
	-----------------------(in thousands)------------------------	
Operating transactions		
Annual operating (deficit) surplus	$ (296)	$ 304
Non-cash items		
Amortization of capital assets	1,615	1,428
Pension expense	827	802
Loss on disposal of capital assets	36	1
(Increase) decrease in accounts receivable	(126)	148
(Increase) decrease in prepaid expenses	(179)	16
Decrease in accounts payable and accrued liabilities	(197)	(1,298)
Cash provided by operating transactions	1,680	1,401
Capital transactions		
Acquisition of capital assets	(746)	(1,042)
Proceeds on disposal of capital assets	2	-
Cash applied to capital transactions	(744)	(1,042)
Financing transactions		
Pension obligations funded	(827)	(802)
Lease incentive received (paid)	19	(43)
Cash applied to financing transactions	(808)	(845)
Increase (decrease) in cash and cash equivalents	128	(486)
Cash and cash equivalents, beginning of year	11,745	12,231
Cash and cash equivalents, end of year	**$ 11,873**	**$ 11,745**

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

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.

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 10 of the financial statements.

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

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

Financial Statement Component	Measurement
Cash and cash equivalents	Cost
Accounts receivable	Lower of cost or net recoverable value
Accounts payable and accrued liabilities	Cost

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

Liabilities

Liabilities represent present obligations of the AUC to external organizations and individuals arising from transactions or events occurring before the year end. They are recorded when there is an appropriate basis of measurement and management can reasonably estimate the amount. Generally, liabilities include trade payables, accrued liabilities and accrued employee vacation entitlements.

Pension

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

For the purpose of calculating pension benefit liability and 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 the active employees, which is 7.1 years.

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.

Deferred lease incentive

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

Non-financial assets

Non-financial assets are limited to capital assets and prepaid expenses.

Capital assets

Capital assets are recorded 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

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

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 expense
Prepaid expense 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 benefit obligations incorporate multiple assumptions. Actual results for amortization and accrued pension obligations may differ from reported values.

Change in accounting policy

Adoption of net financial assets presentation

The net financial assets model (with reclassification of comparatives) has been adopted for the presentation of financial statements. Net financial assets are measured as the difference between the AUC's financial assets and liabilities.

The effect of this change results in changing the presentation of the Statement of Financial Position and adding the Statement of Change in Net Financial Assets.

Note 3 Future accounting changes

In June 2015 the Public Sector Accounting Board issued the following accounting standards:

PS 2200 Related Party Disclosures and PS 3420 Inter-Entity Transactions (effective April 1, 2017)
PS 2200 defines a related party and establishes disclosures required for related party transactions; PS 3420 establishes standards on how to account for and report transactions between public sector entities that comprise a government's reporting entity from both a provider and recipient perspective. Management is currently assessing the impact of these standards on the financial statements.

PS 3210 Assets, PS 3320 Contingent Assets, and PS 3380 Contractual Rights (effective April 1, 2017)
PS 3210 provides guidance for applying the definition of assets set out in Financial Statement Concepts, Section PS 1000, and establishes general disclosure standards for assets; PS 3320 defines and establishes disclosure standards on contingent assets; PS 3380 defines and establishes disclosure standards on contractual rights. Management has completed a review of these standards and does not anticipate any impact on these financial statements.

PS 3430 Restructuring Transactions (effective April 1, 2018)
This standard provides guidance on how to account for and report restructuring transactions by both transferors and recipients of assets and/or liabilities, together with related program or operating responsibilities. Management has completed a review of this standard and does not anticipate any impact on these financial statements.

(in thousands of dollars)

Note 4 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, 2016, securities held by the Fund have a time-weighted return of 0.8 per cent per annum (2015: 1.2 per cent).

Note 5 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, 2016, the balance of accounts receivables does not contain amounts that were past due or uncollectible.

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 $1,969 for the year ended March 31, 2016 (2015: $1,996). 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, 2014. The accrued benefit obligation as at March 31, 2016 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, 2017.

Pension plan assets are valued at market values. During the year ended March 31, 2016 the weighted average actual return on plan assets was -1.71 per cent (11.28 per cent in 2015).

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

	March 31, 2016	March 31, 2015
Accrued benefit obligations		
Discount rate	4.48%	4.73%
Rate of compensation increase	3.50%	3.50%
Long-term inflation rate	2.00%	2.00%

(in thousands of dollars)

Note 6 Pension (continued)

	2016	2015
Pension Benefit costs for the year		
Discount rate	4.73%	5.00%
Expected rate of return on plan assets	4.73%	5.00%
Rate of compensation increase	3.50%	3.75%

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

	March 31, 2016	March 31, 2015
Market value of plan assets	$ 8,543	$ 8,092
Accrued benefit obligations	10,224	9,384
Plan deficit	(1,681)	(1,292)
Unamortized actuarial loss	916	527
Accrued pension liability	$ (765)	$ (765)

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

	2016	2015
Current period benefit costs	$ 647	$ 627
Interest cost	464	427
Expected return on plan assets	(397)	(357)
Amortization of actuarial losses	113	105
	$ 827	$ 802

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

	2016	2015
AUC contribution	$ 827	$ 802
Employees' contribution	112	113
Benefits paid	346	420

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

	March 31, 2016	March 31, 2015
Equity securities	48.40%	51.70%
Debt securities	28.40%	29.40%
Other	23.20%	18.90%
	100.00%	100.00%

(in thousands of dollars)

Note 7 Capital assets

	March 31, 2016				March 31, 2015
	Furniture and equipment	Computer hardware and software	Leasehold improvement	Total	Total
Historical cost					
Beginning of year	$ 2,212	$ 9,662	$ 3,346	$ 15,220	$ 19,410
Additions	10	654	82	746	1,042
Disposals	(5)	(1,303)	-	(1,308)	(5,232)
	$ 2,217	$ 9,013	$ 3,428	$ 14,658	$ 15,220
Accumulated amortization					
Beginning of year	$ 961	$ 4,732	$ 2,271	$ 7,964	$ 11,767
Amortization expense	118	1,122	375	1,615	1,428
Effect of disposals	(5)	(1,265)	-	(1,270)	(5,231)
	$ 1,074	$ 4,589	$ 2,646	$ 8,309	$ 7,964
Net book value at March 31, 2016	**$ 1,143**	**$ 4,424**	**$ 782**	**$ 6,349**	**$ 7,256**
Net book value at March 31, 2015	**$ 1,251**	**$ 4,930**	**$ 1,075**	**$ 7,256**	

Note 8 Accumulated surplus

Accumulated surplus is comprised of the following:

	2016			2015
	Investments in capital assets	Unrestricted surplus	Total	Total
Opening balance	$ 7,256	$ 9,022	$ 16,278	$ 15,974
Annual operating (deficit) surplus	-	(296)	(296)	304
Net investment in capital assets	(907)	907	-	-
Closing balance	$ 6,349	$ 9,633	$ 15,982	$ 16,278

Note 9 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, contracts and maintenance agreements	Total
2017	$ 3,436
2018	3,091
2019	615
2020	206
2021	206
Thereafter	-
	$ 7,554

Note 10 Related party transactions

For the year ended March 31, 2016 the AUC received and paid $156 (2015: $302) for services from other government of Alberta organizations. The AUC also received contributed services from other government of Alberta organizations with an estimated value of $2 (2015: $9). The value of these contributed services have not been recognized in the Statement of Operations. All transactions were in the normal course of operations and measured at the amount of consideration agreed to by the related parties.

Note 11 Comparative figures

Certain 2015 figures have been reclassified to conform to the 2016 presentation.

Note 12 Approval of financial statements

These financial statements were approved by the AUC's Commission Members.

ALBERTA UTILITIES COMMISSION Schedule 1

UTILITY REGULATION EXPENSES - DETAILED BY OBJECT

Year Ended March 31, 2016

	2016		2015
	Budget	**Actual**	**Actual**
	(in thousands)		
Salaries, wages and employee benefits	$ 25,900	$ 23,559	$ 22,851
Supplies and services	9,240	8,161	9,530
Amortization of capital assets	1,800	1,615	1,428
Loss on disposal of capital assets	-	36	1
	$ 36,940	$ 33,371	$ 33,810

ALBERTA UTILITIES COMMISSION Schedule 2

SALARIES AND BENEFITS DISCLOSURE

Year Ended March 31, 2016

	2016				2015
	Base Salary [1]	Other Cash Benefits [2]	Other Non-cash Benefits [3]	Total	Total
	(in thousands)				
Chair of the Commission	$ 348	$ 46	$ 115	$ 509	$ 479
Vice-Chair	219	30	16	265	280
Commission Member	197	10	64	271	261
Commission Member	197	8	59	264	267
Commission Member	197	27	15	239	245
Commission Member	197	27	14	238	249
Commission Member	197	33	8	238	242
Commission Member [4]	188	55	14	257	235

(1) Includes pensionable base pay.

(2) Includes payments in lieu of vacation, health and pension benefits.

(3) Employer's contributions to all employee benefits including Employment Insurance, Canada Pension Plan, Alberta pension plans, health benefits, professional memberships and tuition fees. Automobiles were provided but no dollar amount included in other non-cash benefits.

(4) Position has been vacant since March 16, 2016.

ALBERTA UTILITIES COMMISSION
AUTHORIZED BUDGET
Year Ended March 31, 2016

Schedule 3

	Plan			
	Budget (Estimate)	**Authorized Changes**	**Authorized Budget**	**Actual**
	(in thousands)			
Revenues				
Administration fees	$ 35,740	$ -	$ 35,740	$ 32,855
Investment income	300	-	300	172
Professional services	100	-	100	48
	36,140	-	36,140	33,075
Expenses				
Utility regulation	36,940	-	36,940	33,371
Net Capital Investment				
Capital investment	1,000	-	1,000	746
Less:				
Amortization	(1,800)	-	(1,800)	(1,615)
Loss on disposal of capital assets	-	-	-	(36)
Proceeds on disposal of capital assets	-	-	-	(2)
	(800)	-	(800)	(907)
	$ -	$ -	$ -	$ 611

Note:

The Budget is based on the AUC Business Plan for the year ended March 31, 2016. The Budget and Authorized Changes have been approved by the government of Alberta.

ALBERTA PETROLEUM MARKETING COMMISSION

FINANCIAL STATEMENTS
For the year ended December 31, 2015

Independent Auditor's Report

To the Board of Directors of the Alberta Petroleum Marketing Commission

Report on the Financial Statements

I have audited the accompanying financial statements of the Alberta Petroleum Marketing Commission, which comprise the statement of financial position as at December 31, 2015, and the statements of income and comprehensive income, changes in net assets and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, 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.

Auditor's Responsibility

My responsibility is to express an opinion on these financial statements based on my audit. I conducted my audit in accordance with Canadian generally accepted auditing standards. Those standards require that I comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements 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 entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my audit opinion.

Opinion

In my opinion, the financial statements present fairly, in all material respects, the financial position of the Alberta Petroleum Marketing Commission as at December 31, 2015, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

Original signed by Merwan N. Saher, FCPA, FCA
Auditor General

May 5, 2016

Edmonton, Alberta

Alberta Petroleum Marketing Commission

Statement of Financial Position
As at December 31
(thousands of Canadian dollars)

	2015	2014
Assets		
Cash and short term investments (Note 6)	$ 5,123	$ 15,182
Accounts receivable	71,368	153,558
Prepaid expenses	13	12
Intangible assets under development (Notes 7 and 14)	3,634	1,271
Term loan (Note 8)	225,000	112,500
Accrued interest on term loan	28,893	7,627
Total assets	$ 334,031	$ 290,150
Liabilities		
Accounts payable (Note 9)	$ 23,062	$ 43,054
Due to the Department of Energy (Note 10)	54,471	123,545
Short term debt (Note 11)	225,000	112,500
Accrued interest on short term debt	2,950	844
Total liabilities	$ 305,483	$ 279,943
Net assets	$ 28,548	$ 10,207
Total liabilities and net assets	$ 334,031	$ 290,150

Commitments (Note 13)

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

Alberta Petroleum Marketing Commission

Statement of Income and Comprehensive Income
For the year ended December 31
(thousands of Canadian dollars)

	2015	2014
Conventional crude oil marketing operations		
Marketing fee revenue (Note 14)	$ 3,895	$ 7,678
Finance income	79	219
	3,974	7,897
Expense		
Wages and benefits (Note 14)	3,776	4,181
Consulting	405	666
Software and maintenance (Note 14)	383	102
Travel	77	79
Dues and subscriptions	76	79
Directors' fees	34	16
Telephone	17	19
Conferences	10	17
Other	12	35
	4,790	5,194
Net income from conventional crude oil marketing operations	(816)	2,703
Sturgeon Refinery		
Finance income	21,266	7,627
Finance costs	(2,106)	(844)
Trust costs	(3)	(11)
Net income attributable to Sturgeon Refinery (Note 5(c))	19,157	6,772
Net income and comprehensive income	$ 18,341	$ 9,475

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

Alberta Petroleum Marketing Commission

Statement of Changes in Net Assets
For the year ended December 31
(thousands of Canadian dollars)

	2015	2014
Net Assets, beginning of year	$ 10,207	$ 732
Net income and comprehensive income	18,341	9,475
Net assets, end of year	$ 28,548	$ 10,207

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

Alberta Petroleum Marketing Commission

Statement of Cash Flows
For the year ended December 31
(thousands of Canadian dollars)

	2015	2014
Operating activities		
Net income and comprehensive income	$ 18,341	$ 9,475
Non-cash items included in net income		
Accrued interest on term loan	(21,266)	(7,627)
Accrued interest on short term debt	2,106	844
Changes in non-cash working capital		
Decrease in accounts receivable	82,190	53,110
(Increase) decrease in prepaid expenses	(1)	-
(Decrease) in accounts payable	(19,992)	(8,248)
(Decrease) in due to Department of Energy	(69,074)	(46,163)
Net cash from operating activities	(7,696)	1,391
Investing activities		
Term loan	(112,500)	(112,500)
Intangible assets under development	(2,363)	(1,271)
Net cash used in investing activities	(114,863)	(113,771)
Financing activities		
Proceeds from issuance of short term debt	112,500	112,500
Net cash from financing activities	112,500	112,500
(Decrease) increase in cash and short term investments	(10,059)	120
Cash and short term investments, beginning of year	15,182	15,062
Cash and short term investments, end of year	$ 5,123	$ 15,182

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

ALBERTA PETROLEUM MARKETING COMMISSION
NOTES TO THE FINANCIAL STATEMENTS
(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 the Province 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 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. In July 2014 two outside directors were added. In May 2015 a Department board member retired to bring the total number of board members to four.

The Commission's mandate has been enhanced to include assisting in the development of new energy markets, transportation infrastructure and managing the implementation of Alberta's Bitumen Royalty In Kind (BRIK) policy. In line with that is the Commission's involvement with North West Redwater Partnership ("NWRP" or "Sturgeon Refinery") and the commitment to capacity on the Energy East Pipeline Project. The Commission has set up 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 May 5, 2016.

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, in the Commission's opinion, been properly prepared within reasonable limits of materiality and within the framework of the accounting policies summarized below.

(a) Revenue recognition

The Commission acts 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 earns revenue through marketing fees collected from the Department based on net volumes sold.

Revenue is recognized from marketing fees 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 $568 is being held in a fiduciary capacity on behalf of the Department at December 31, 2015 ($1,554 as at December 31, 2014). 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.

(b) 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.

(c) Financial instruments

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

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

Financial assets and liabilities are offset and the net amount reported in the balance sheet when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis or realize the asset and settle the liability simultaneously.

(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 and comprehensive income.

(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 and comprehensive income 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 obtained for internal use are capitalized if it is probable that 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 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. Software under development is reviewed annually for impairment. 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 and Comprehensive Income.

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 and Comprehensive Income.

Note 4 New standards and accounting pronouncements not yet effective

A number of new accounting standards, amendments to accounting standards and interpretations are effective for annual periods beginning on or after January 1, 2016 and have not been applied in preparing the Financial Statements for the year ended December 31, 2015. The standards applicable to the Commission are as follows and will be adopted on their respective effective dates.

(a) Revenue recognition

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. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded.

The new standard is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. The standard may be applied retrospectively or using a modified retrospective approach. The Commission will adopt the standard when it becomes effective and does not anticipate that this standard will result in significant accounting changes.

(b) 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 APMC does not currently apply hedge accounting.

IFRS 9 is effective for years beginning on or after January 1, 2018. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. The Commission will adopt the standard when it becomes effective and does not anticipate that this standard will result in significant accounting changes.

Note 5 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 the accounting policy choice. 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 North West Redwater Partnership and Energy East Pipeline Project 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 significant judgment in determining whether it is acting as a principal or agent with respect to conventional crude oil marketing activities. The Commission would be acting as a principal if it has exposure to the significant risks and rewards associated with rendering the marketing services. The Commission accepts delivery of and markets the Province'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. However, the Commission is not exposed to significant inventory, credit, or price risk, and therefore does not have the exposure to the significant risks and rewards of ownership, which is indicative of an agency relationship. 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 and Comprehensive Income would have included additional revenues, expenses and amounts to be transferred to the Department of $788,728 revenues, $86,830 expenses and $701,898 royalties to be transferred to the Department respectively ($2,568,641 revenues, $184,085 expenses and $2,384,556 royalties to be delivered to the Department - 2014).

(c) NWRP – Significant influence

In 2015 APMC lent an additional $112.5 million to NWRP (total as at December 31, 2015 $225 million) in the form of a term loan. NWRP is a general partnership formed by Canadian Natural Upgrading Limited, a wholly-owned subsidiary of Canadian Natural Resources Limited and by NWU LP, a limited partnership comprised of North West Upgrading Inc. as limited partner and 1726702 Alberta Ltd. (a wholly-owned subsidiary of North West Upgrading Inc.) as general partner. NWRP was formed under the Partnership Act (Alberta) pursuant to a partnership agreement dated February 15, 2011, as amended on November 7, 2012, March 11, 2013 and April 7, 2014. The partners each have a 50% partnership interest in NWRP.

NWRP has entered into various agreements to construct and operate a refinery 45 kilometres north-east of Edmonton to have the capacity to process approximately 50,000 barrels per day (bbl/d) of bitumen at an estimated Facility Capital Cost of $8.5 billion. 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 a commercial operations date of the 4th quarter of 2017.

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.

The Commission has exercised substantial judgement 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 Commission's financial statements, however will provide summarized NWRP financial information in these notes. See Note 8 for further details.

(d) NWRP - Monthly toll commitment

The Commission has used judgement to estimate the toll commitments included in Note 13 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.

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

(f) Energy East – Monthly toll commitment

The Commission has used judgement to estimate the toll commitments included in Note 13 Commitments. This estimate is based on the terms and conditions agreed to within the Transportation Service Agreement (TSA), including the contract term and capacity commitment, as well as a per barrel toll estimate outlined in an updated December 2015 National Energy Board (NEB) project filing.

Note 6 Cash and short term investments

Cash and short term investments consist of a deposit in the Consolidated Cash Investment Trust Fund (the "Fund") which is managed by Treasury Board and Finance to provide competitive interest income while maintaining maximum 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, 2015, securities held by the Fund have a rate of return of 0.93% per annum (1.19% per annum – 2014). Due to the short term nature of Fund investments the carrying value approximates fair value.

(in thousands of Canadian dollars unless otherwise stated)

Note 7 Intangible assets under development

	December 31, 2015	December 31, 2014
Balance, beginning of year	$ 1,271	$ -
Additions	2,363	1,271
Balance, end of year	$ 3,634	$ 1,271

Note 8 Term loan

	December 31, 2015	December 31, 2014
Balance, beginning of year	$ 112,500	$ -
Additions	112,500	112,500
Balance, end of year	$ 225,000	$ 112,500

The Commission lent an additional $112.5 million to NWRP as a term loan on January 2, 2015. 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, 2015. This information has been prepared in accordance with IFRS as issued by the IASB.

	NWRP (100% Interest)	
	2015	*2014*
Current assets	$ 138,868	$ 132,235
Non-current assets	$ 5,837,033	$ 3,064,235
Current liabilities	$ 681,077	$ 453,475
Non-current liabilities	$ 4,785,720	$ 2,145,797
Partners' equity	$ 509,104	$ 597,198
Revenue	$ -	$ -
Net loss and comprehensive loss attributable to Partners	$ 88,094	$ 16,494

(in thousands of Canadian dollars unless otherwise stated)

Non-current assets primarily consist of property plant and equipment, which includes: engineering; procurement activities; site construction costs; module fabrication; and other costs directly attributable to the project. Non-current liabilities chiefly comprise of 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 attributable to Partners primarily contains foreign exchange losses and general and administrative costs.

Note 9 Accounts payable

	December 31, 2015	December 31, 2014
Trade Payables	*$ 15,150*	*$ 22,651*
GST	*7,912*	*20,403*
	$ 23,062	*$ 43,054*

Note 10 Due to the Department of Energy

	December 31, 2015	December 31, 2014
Due to Department, beginning of year	*$ 123,545*	*$ 169,708*
Amount to be transferred	*701,898*	*2,384,556*
Amount remitted	*(770,972)*	*(2,430,719)*
Due to Department, end of year	*$ 54,471*	*$ 123,545*

Note 11 Short term debt

	December 31, 2015	December 31, 2014
Balance, beginning of year	$ 112,500	$ -
Additions	112,500	112,500
Balance, end of year	$ 225,000	$ 112,500

On April 8, 2015 APMC replaced the original $112.5 million short term debt with Treasury Board and Finance at 0.696% interest, with a due date of April 6, 2016. Additionally on December 31, 2015 APMC replaced the secondary $112.5 million short term debt with Treasury Board and Finance at 0.729% interest with a due date of December 23, 2016. APMC's intention is to borrow additional short term funds from Treasury Board and Finance when these amounts come due and repay the aggregated amounts over 10 years starting the year after the Sturgeon Refinery start-up. The timing of APMC repaying this debt will correspond to NWRP's repayment of the term loan to the Commission.

Note 12 Financial instruments

The Commission's financial instruments consist of cash and short term investments, accounts receivable, term loan, accounts payable, short term debt and amounts due to the Department. The Commission has classified cash and short term investments, accounts receivable and term loan as loans and receivables, and accounts payable, due to the Department and short term debt as financial liabilities at amortized cost. The Commission's financial instruments are initially recorded at amortized cost using the effective interest method. The fair values of the financial instruments approximate their carrying values due to the short term maturities of those instruments.

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, 2014.

(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 6). For 2014 and 2015, a 100 basis point change would have a nominal effect on net income.

There is interest rate risk related to the term loans issued April 8, 2015 and December 31, 2015. APMC earns interest at a rate of prime plus 6%, compounded monthly. A 100 basis point rise in prime would have improved 2015 net income by $2.5 million (2014 $0.9 million). A 100 basis point decline in prime would have reduced 2015 net income by $2.5 million (2014 $0.9 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 and accounts receivable. 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 6).

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 an allowance for credit losses is provided in the period in which losses become known. There were no balances past their contractual due date as at December 31, 2015 and December 31, 2014. Any credit losses on accounts receivable would be passed on to the Department.

APMC has issued two term loans totaling $225.0 million to NWRP on April 8, 2015 and December 31, 2015. NWRP is an investment grade counterparty. Bonds issued by NWRP received an A- credit rating 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.

(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.

(in thousands of Canadian dollars unless otherwise stated)

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 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	$ 125,058	$ 53,690	$ 71,368
Accounts payable	(79,218)	(56,156)	(23,062)
Net position, December 31, 2015	$ 45,840	$ (2,466)	$ 48,306
Accounts receivable	$ 258,806	$ 105,248	153,558
Accounts payable	(153,881)	(110,827)	(43,054)
Net position, December 31, 2014	$ 104,925	$ (5,579)	$ 110,504

(e) Capital management

The capital structure includes the Commission's net assets. 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. 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 13 Commitments

	2016	*2017*	*2018*	*2019*	*2020*	*Beyond 2020*
NWRP Tolls	*$ -*	*$ 102,000*	*$ 637,000*	*$ 713,000*	*$ 912,000*	*$ 22,386,000*
Energy East Pipeline	*$ -*	*$ -*	*$ -*	*$ -*	*$ 230,000*	*$ 4,370,000*

(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 and market Crown royalty bitumen, or equivalent volumes, collected pursuant to the Bitumen Royalty in Kind initiative in order to capture additional value within Alberta. NWRP will market the refined products (primarily ultra low sulphur diesel and low sulphur vacuum gas oil) on behalf of the 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, 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 $8.5 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 term of the commitment begins upon the commencement of commercial operations. No amounts have been paid under this agreement to date.

The nominal tolls under the processing agreement, assuming an $8.5 billion Facility Capital Cost, market interest rates and 2% operating cost inflation rate, are estimated above. The total estimated tolls have been reduced by $1.26 billion relative to 2014, due primarily to lower debt tolls. As at December 31, 2015 NWRP has issued $2.8 billion in bonds at lower than anticipated rates and expects future bond offerings to continue this trend.

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

(b) Energy East Pipeline Project

The Commission has signed a TSA with Energy East Pipeline Limited Partnership (the "Carrier") to purchase 100,000 barrels per day of firm capacity for a term of 20 years to transport volumes of crude oil. The construction of the pipeline is dependent upon obtaining regulatory approval. The Carrier filed an updated project cost estimate with the NEB in December 2015. Under the take-or-pay obligation, once required regulatory and commercial approvals are obtained, the Commission has an estimated updated minimum obligation to pay $4.6 billion ($3.4 billion – 2014) in tolls over the 20 year term. Additional tolls will be incurred depending on the volumes transported through the pipeline. The pipeline is expected to be in service as early as 2020.

(c) NWRP Term loan

As part of the Subordinated Debt Agreement with NWRP, APMC is committed to loan an additional amount in 2016 of $99.363 million. This amount and the accrued interest will be repaid by NWRP beginning one year after commercial start-up of the Sturgeon Refinery. These amounts will be repaid straight line over ten years plus accrued interest.

Upon initiation of commercial operations the total amount of the term loan will be adjusted to reflect an agreed equity to debt ratio.

Note 14 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 and Comprehensive Income. The amounts owing to the Department have been disclosed in Note 10.

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 (2015 $2,088, 2014 $2,606) and Software and maintenance (2015 $163, 2014 $55) within the statement of income and comprehensive income. In addition some of the Department salaries have been capitalized within Intangible assets under development (2015 $252, 2014 $123).

The Commission has outstanding short term debt with Treasury Board and Finance. For more details see Note 11.

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 15.

(in thousands of Canadian dollars unless otherwise stated)

Note 15 Salaries and benefit disclosure

Key management personnel include the Commission's Chief Executive Officer, Executive Director Business Development and Director of Finance. The following amounts in the financial statements relating to board members and key management compensation in 2015 and 2014 are as follows:

	2015				2014
	Base Salary	Other Cash Benefits	Other Non-cash Benefits (2)	Total	Total
Board Members (1)	$ -	$ 34	$ -	$ 34	$ 16
Chief Executive Officer	$ 630	$ -	$ 5	$ 635	$ 635
Senior Management					
Executive Director, Business Development	$ 445	$ -	$ 8	$ 453	$ 453
Director of Finance	$ 259	$ -	$ 8	$ 267	$ 267

(1) The Chairman of the Board (Deputy Minister, Department of Energy) and one director (Assistant Deputy Minister, Department of Energy) are unpaid. Two outside directors were appointed in July, 2014. They receive an annual retainer and meeting fees.

(2) Included in Other Non-cash benefits are employer contributions to Canada Pension Plan, Employment Insurance, reimbursement of parking and fitness facility membership costs.

Note 16 Subsequent events

Term loan to NWRP

On January 4, 2016 APMC issued an additional $99.363 million term loan to NWRP on the same terms and conditions as the term loan issued on April 9, 2014 (see Note 8).

Short term debt

On January 4, 2016 the Commission borrowed $99.363 million of short term debt from Treasury Board and Finance at an effective interest rate of 0.717% due December 31, 2016.

On April 6, 2016 the Commission replaced its short term debt originally issued April 8, 2015 with new short term debt of $114.439 million at 0.709% interest due April 5, 2017.

APMC's intention is to borrow additional short term funds when these amounts come due and repay the aggregated amount straight line over 10 years starting the year after the Sturgeon Refinery start-up.

POST-CLOSURE STEWARDSHIP FUND

FINANCIAL STATEMENTS
For the year ended March 31, 2016

Independent Auditor's Report

AUDITOR GENERAL *Alberta*

To the Minister of Energy

Report on the Financial Statements

I have audited the accompanying financial statements of the Post-closure Stewardship Fund, which comprise the statement of financial position as at March 31, 2016 and the statement of operations, change in net financial assets and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these 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 financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

My responsibility is to express an opinion on these financial statements based on my audit. I conducted my audit in accordance with Canadian generally accepted auditing standards. Those standards require that I comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements 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 entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my audit opinion.

Opinion

In my opinion, the financial statements present fairly, in all material respects, the financial position of the Post Closure Stewardship Fund as at March 31, 2016, 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.

Original signed by Merwan N. Saher, FCPA, FCA
Auditor General

June 6, 2016

Edmonton, Alberta

POST-CLOSURE STEWARDSHIP FUND

STATEMENT OF OPERATIONS

Year ended March 31, 2016

(in thousands)

	2016		2015
	Budget	**Actual**	**Actual**
Revenue			
Injection Levy (Note 3)	$ 100	$ 148	$ -
Net Operating Results	**$ 100**	**$ 148**	**$ -**

The accompanying notes are part of these financial statements.

POST-CLOSURE STEWARDSHIP FUND

STATEMENT OF FINANCIAL POSITION

As at March 31, 2016

(in thousands)

	2016	2015
Assets		
Accounts Receivable	$ 148	$ -
Net Assets	**$ 148**	**$ -**
Net Assets at Beginning of Year	$ -	$ -
Annual Operating Results	148	-
Net Assets at End of Year	**$ 148**	**$ -**

The accompanying notes are part of these financial statements.

POST-CLOSURE STEWARDSHIP FUND

STATEMENT OF CHANGE IN NET FINANCIAL ASSETS

Year ended March 31, 2016

(in thousands)

	2016		2015
	Budget	Actual	Actual
Annual Operating Results	$ 100	$ 148	$ -
Increase in Net Assets	$ 100	$ 148	$ -
Net Assets at Beginning of Year	-	-	-
Net Assets at End of Year	**$ 100**	**$ 148**	**$ -**

The accompanying notes are part of these financial statements.

POST-CLOSURE STEWARDSHIP FUND

STATEMENT OF CASH FLOWS

Year ended March 31, 2016

(in thousands)

	2016	2015
Operating Transactions		
Net Operating Results	$ 148	$ -
(Increase) in Accounts Receivable	(148)	-
Increase (Decrease) in Cash and Cash Equivalents	**$ -**	**$ -**
Cash and Cash Equivalents at Beginning of Year	-	-
Cash and Cash Equivalents at End of Year	**$ -**	**$ -**

The accompanying notes are part of these financial statements.

POST-CLOSURE STEWARDSHIP FUND
NOTES TO FINANCIAL STATEMENTS
Year ended March 31, 2016

Note 1 Authority and 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 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.

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 Basis of Financial Reporting

Revenues

These financial statements are prepared in accordance with Canadian public sector accounting standards.

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, 2016, 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, less than 1% 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 Approval of Financial Statements

The financial statements were approved by the Deputy Minister and the Senior Financial Officer of the Department of Energy.

Statutory Report

Public Interest Disclosure Act

Section 32 of the Public Interest Disclosure Act requires the ministry to report annually on the following parts of the Act:

a. the number of disclosures by the designated officer of the Public Interest Disclosure Office, 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.

In 2015-16, there were no disclosures of wrongdoing filed with the Public Interest Disclosure Office for the ministry.

Other Information

For additional copies, please contact:

Finance and Administration
Business Planning and Performance
Alberta Department of Energy
14th Floor, North Petroleum Plaza
9945 - 108 Street
Edmonton, Alberta T5K 2G6

Tel: 780-427-8050
To call toll free within Alberta, dial 310-0000 first.

The Ministry of Energy Annual Report 2015-16 is available on the following website:
www.energy.alberta.ca/About_Us/1001.asp

Current information about the organizations that were part of the Ministry of Energy in 2015-16 is available at the following websites:

For the Department of Energy:
www.energy.alberta.ca

For the Alberta Energy Regulator:
www.aer.ca

For the Alberta Utilities Commission:
www.auc.ab.ca

MINISTRY OF ENERGY 2015-2016

www.energy.alberta.ca

www.aer.ca

www.auc.ab.ca

ISSN 1703-4574 (Print)

ISSN 1703-4582 (Online)