Energy

Annual Report
2013-2014

Alberta Government

Energy

Annual Report 2013-2014

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Preface

The Public Accounts of Alberta are prepared in accordance with the *Financial Administration Act* and the *Fiscal Management Act*. The Public Accounts consist of the annual report of the Government of Alberta and the annual reports of each of the 19 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 Management 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, 2014, was prepared under my direction in accordance with the *Fiscal Management Act* and the government's accounting policies. All of the government's policy decisions as at June 4, 2014 with material economic or fiscal implications of which I am aware have been considered in the preparation of this report.

Original signed by Honourable Diana McQueen
Minister of Energy

Minister's Message

Alberta Energy's mission is to ensure sustained prosperity in the best interests of Albertans through the stewardship of energy and mineral resource systems, responsible development and wise use of energy. This includes a focus on the social, economic and environmental impacts of Alberta's resource development.

Alberta has one of the largest heavy oil deposits in the world. This past year, crude bitumen production reached its highest level ever and, for the fifth fiscal year in a row, bitumen royalty was the top contributor to Alberta's non-renewable resource revenue mix. This growth creates jobs for Albertans and tax revenues for government to support social programs and capital infrastructure projects.

Our government recognizes the importance of opening new markets for Alberta's resources to get fairer prices to further strengthen our economy. Alberta has products that world markets want, and we're exploring all our options to get our products to these markets. We are committed to supporting pipeline and infrastructure development and have embarked on missions in Canada and abroad to promote Alberta's products, establish new markets and to showcase Alberta as a secure and responsible energy supplier.

A key part of my job is to tell Alberta's energy story in Canada and across the world and to build partnerships that will support greater prosperity for the province. Over the past year, Alberta Energy has helped expand market access opportunities in Asia through formal trade agreements for energy products, services, and expertise. In the fall sitting of the Legislature, we also passed the *Building New Petroleum Markets Act*, which boosts our government's ability to respond to changing market conditions and empower the Alberta Petroleum Marketing Commission to proactively seek out opportunities for the strategic use of Alberta's energy products.

Recognizing the importance of collaboration with our provincial and territorial partners, Alberta Energy continued its work supporting the Canadian Energy Strategy. I am committed to building awareness of energy issues and cooperating on energy solutions to cement Alberta's and Canada's place as a global energy leader. The strategy will help Alberta and Canada remain leaders in sustainable and secure energy production.

The ministry has also actively worked with its partner ministries and stakeholders to implement the Integrated Resource Management System (IRMS). This system ensures that the province takes a coordinated approach that examines all parts of resource development promoting responsible resource and environmental stewardship. In 2013, we also achieved a major milestone under the IRMS. Energy, Environment and Sustainable Resource Development, and the Alberta Energy Regulator (AER) completed the transition to a single energy regulator, with the AER becoming responsible for all oil, gas, oil sands and coal projects, from application to reclamation, and enforcing all legislation related to these projects. This transition has improved Alberta's regulatory framework and enables a more efficient system.

In the past year, Albertans' demand for electricity increased and this demand was met with an increase in the province's generation capacity. New records for peak electricity demand were set in the extreme hot and cold temperatures of July and December. Within government, we continued our efforts to protect consumers against high electricity costs. This includes the ongoing work of the MLA Retail Market Review Committee Implementation Team and making changes to the Transmission Regulation that gives the Alberta Utilities Commission greater authority to scrutinize the costs of transmission lines.

Last year also saw our province's ability to respond to a crisis put to the test. The floods of June 2013 had a great impact on Alberta's energy infrastructure, especially the province's electricity and natural gas utilities. The flooding knocked out power to affected neighbourhoods and the electricity distributors worked tirelessly to get the system up and running again. Flooding also damaged natural gas pipelines resulting in disruptions to gas distribution and damage to gas appliances. Due to the quick action of the natural gas utility providers, natural gas service to homes and businesses was restored and replaced in a timely manner. The AER responded by monitoring pipeline integrity even as its own headquarters in downtown Calgary was closed from the flooding.

It is important to acknowledge the incredible dedication of so many Energy employees and energy sector staff who worked long hours as we responded to the crisis in Southern Alberta.

On behalf of our government, I want to thank all of the incredible and dedicated team who work at Alberta Energy. The commitment you show to your job and indeed your province is truly remarkable and I am so very honoured to have the opportunity to work with all of you.

Original signed by Honourable Diana McQueen
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 agrees with underlying data and the sources used to prepare it.
- Understandability and Comparability – current results are presented clearly in accordance with the stated methodology and are comparable with previous years.
- Completeness - performance measures and targets match those included in the Ministry's Budget 2013.

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 Management Act.*

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

Original signed by Grant D. Sprague, Q.C.
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

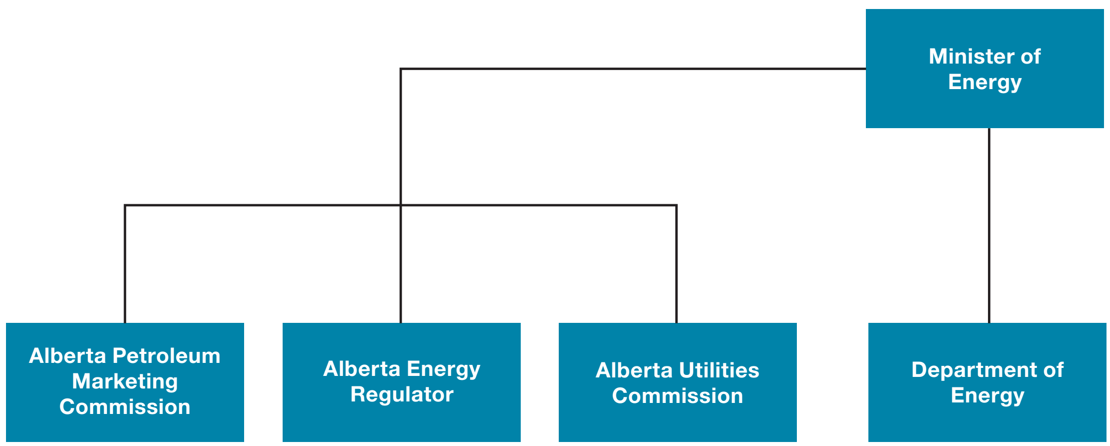
Original signed by Richard Masson
Chief Executive Officer
Alberta Petroleum Marketing Commission

Date: June 4, 2014

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, 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 (DOE), the Alberta Energy Regulator (AER), the Alberta Utilities Commission (AUC) and the Alberta Petroleum Marketing Commission (APMC). Each entity plays important roles in overseeing the orderly development of Alberta's energy resources.



Sustaining and building organizational capacity is fundamental to the ministry's effectiveness. Positioning the ministry to respond optimally to current and evolving business requirements requires having the right resources, people, finances, information, technology, processes and tools in place.

DOE	▪ 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 (including natural gas, conventional oil, oil sands, coal and 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 ▪ Promotes energy efficiency and conservation by Albertans and industry ▪ Encourages investment in Alberta's energy industry to create jobs and economic prosperity for Albertans ▪ Establishes the framework for responsible industry-led investment in electricity infrastructure and markets for the reliable delivery of electricity to all consumers

AER	▪ Independently makes decisions regarding resource development in accordance with applicable legislation and within the framework of Alberta's overall energy policy ▪ Proactively 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

AUC	▪ 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 AUC ▪ Ensures the delivery of Alberta's utility services takes place in a manner that is fair, responsible and in the public interest

APMC	▪ 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 (BRIK) policy

The Energy Story

Energy development is driving Alberta's economy and continues to build a solid foundation for our province's future. In the past fiscal year, there were many components to Alberta's energy story.

Alberta's Accomplishments

Record Production

Crude bitumen production in Alberta in 2013-14 reached its highest level ever. With more than two million barrels per day, Alberta demonstrated that despite market challenges, the province's oil industry is vibrant.

For the fifth fiscal year in a row, oil sands made up most of Alberta's non-renewable resource royalty revenue. It accounted for $5.2 billion of $9.6 billion non-renewable resource royalty revenue in 2013-14. On the whole, energy non-renewable resource revenue is 23 per cent higher than last year due to higher oil prices, a lower differential and a lower Canadian dollar.

Alberta continues to have a combined royalty and tax rate that is in the top quartile of investment opportunities when compared to similar jurisdictions. Business processes, systems and controls continue to result in accurate assessment, calculation and collection of revenues.

Canadian Energy Strategy

Alberta, Manitoba, and Newfoundland and Labrador are leading the development of the Canadian Energy Strategy. The Canadian Energy Strategy will help Canada remain a leader in sustainable and secure energy production, supply and transportation by having provinces and territories work together to create jobs, expand their economies, build manufacturing opportunities, and advance research and technological innovations. Securing market access requires working with industry and other stakeholders to develop a shared understanding of the value and importance of energy transportation infrastructure and engaging with Canadian and foreign governments on energy policy issues. Cross-provincial and territorial teams are continuing work on 10 areas of focus. Alberta is leading four of the teams and is participating on the other six. A progress report was released in July 2013.

Market Access for Alberta's Resources

The department supported missions to the United States, Europe and Asia to establish new markets for Alberta's resources and to showcase the province as a secure and responsible energy supplier.

In 2013-14, the department expanded market access opportunities in Asia through formal agreements that take Alberta one step forward by ensuring over-arching political endorsement, and by creating multiple pathways for trade in energy products, services, and expertise. The agreements include the Framework Agreement on Sustainable Energy Development with the National Energy Administration of China; The Alberta Petroleum Marketing Commission's (APMC) Expression of Intent to Collaborate with the Indian Oil Corporation; and additional agreements developed in Japan and Korea.

As well, the *Building New Petroleum Markets Act* boosts government's ability to respond more quickly to changing market conditions and empowers the APMC to proactively seek out opportunities for Alberta's energy products. An example of a strategic opportunity sought out by the APMC in 2013-14 was committing 100,000 barrels of oil per day to the Energy East project as a way of helping the project move forward.

Getting Our Energy Products to Market Safely

Increased crude oil and natural gas production in North America has overwhelmed the capacity of existing pipelines to carry these products to market. Because of this, an estimated 175,000 barrels of crude oil per day are currently being shipped by rail out of Western Canada to international markets. High profile train derailments over the past year have led to new safety measures being implemented. Alberta took quick action to implement recommendations from the Lac Mégantic investigation and is also developing a broader rail safety strategy for provincially-regulated railways.

With many proposed pipelines in the development phase, overall safety is top of mind for many Albertans. Pipelines are considered to be the safest way of transporting oil and gas products. In 2013-14, the Pipeline Safety Review found that Alberta is a leader in pipeline safety regulation, but that there is room for improvement.

Whether by rail or by pipeline, Alberta will develop safe and effective ways to access tidewater and get its oil to international markets.

Transfer to a Single Energy Regulator

The Alberta Energy Regulator (AER) ensures that Alberta will responsibly develop its resources while maintaining the province's strong commitment to the environment and public safety. Energy, Environment and Sustainable Resource Development, and the AER completed the transition to the single regulator in 2013-14. The AER is now responsible for all oil, gas, oil sands and coal projects, from application to reclamation.

The AER has instituted a Private Surface Agreement Registry that allows landowners and occupants to register surface agreements made with energy companies operating on their property. If a landowner feels that a company is not meeting a term or condition of a registered agreement, they can request that the AER intervene, which could result in an order to comply.

Electricity Enhancements for Albertans

In 2013-14, Alberta expanded electricity generation capacity, but also experienced peak demand for electricity, breaking records when the province experienced extreme hot temperatures in July and cold temperatures in December. The Government continues to monitor Alberta's electricity system to manage transmission costs, conduct system planning, and manage transmission line losses and congestion.

The Member of the Legislative Assembly (MLA) Retail Market Review Committee Implementation Team continued to look at ways of protecting Albertans from high electricity costs. The MLAs met with stakeholders, including electricity consumer groups, rural electrification associations and electricity producers in the course of developing an implementation plan for 33 of the recommendations found in the Retail Market Review Committee's 2012 report. The Alberta Utilities Commission was given greater authority to scrutinize the costs of transmission lines through the Transmission Regulation.

In 2013-14, Alberta's electricity transmission network was expanded. The Heartland Transmission Line, which links south Edmonton to the Heartland industrial area north of the city, was brought online in December 2013. As well, the Montana-Alberta Tie Line was brought online which links southern Alberta and Montana. Also, a competitive procurement process for a new transmission line to Fort McMurray began. Five companies were selected to develop bids for this line.

Action on Climate Change

More than 45 per cent of Alberta's electricity generating capacity comes from alternative and renewable energy sources including wind, hydro, biomass and natural gas cogeneration. The department is developing an Alternative and Renewable Energy Policy Framework to shape the way we move forward on alternative and renewable energy.

Since 2011, the department's Renewable Fuels Standard has reduced greenhouse gas (GHG) emissions by one million tonnes per year. Four biofuel facilities are currently under development and will increase Alberta's biofuel capacity from approximately 85 million litres to 464 million litres of biofuel annually by 2015.

In 2013-14, the department released the Regulatory Framework Assessment Report to support carbon capture and storage (CCS). Over the next three years, the department will work on implementing the 71 recommendations in the report, which will help ensure that CCS is conducted in the safest and most environmentally responsible manner possible. The department also continues to support two large-scale CCS projects, the Alberta Carbon Trunk Line and Shell Quest Project. These projects can reduce Alberta's GHG emissions by about 2.8 million tonnes per year by 2016: the equivalent of taking 550,000 cars off the road.

Protecting our Natural Habitats

The Lower Athabasca Regional Plan (LARP), the first of seven regional plans under the Land-Use Framework, will help manage Alberta's land and natural resources to achieve long-term economic, environmental and social goals. Conservation areas protected under LARP promote biodiversity by protecting habitats for wildlife, such as caribou populations. Work on the South Saskatchewan Regional Plan and Lower Peace Regional Plan is underway.

In 2013-14, the department cancelled 76 oil sands and metallic and industrial minerals leases, or portions, which fell within the boundaries of the new protected areas.

Conclusions

The ministry plays an important role as stewards of Alberta's energy and natural resource systems, facilitating the development and use of resources in a sustainable manner for the benefit of all Albertans. The initiatives identified above are only a select few of the actions undertaken by the ministry. The development and successful implementation of these initiatives is critical to the long-term success of Alberta as a global energy leader.

Energy Highlights

Resource		2013-14	2012-13
Bitumen	Revenue	$5.22 billion	$3.56 billion
	Percentage of non-renewable resource revenue	55%	46%
	Bitumen wells drilled	2,123 (2013)	1,991 (2012)
	Total bitumen production in barrels per day (bbl/d)	2.09 million bbl/d (2013)	1.92 million bbl/d (2012)
	Marketable bitumen and Synthetic Crude Oil (SCO) production	1.94 million bbl/d (2013)	1.78 million bbl/d (2012)
Conventional Crude Oil	Revenue	$2.48 billion	$2.04 billion
	Percentage of non-renewable resource revenue	26%	26%
	Average price for West Texas Intermediate per barrel	US$99.05	US$92.07
	Crude oil production	0.58 million bbl/d (2013)	0.56 million bbl/d (2012)
	Pentanes and condensate production	0.13 million bbl/d (2013)	0.12 million bbl/d (2012)
	Crude oil wells drilled	2,493 (2013)	2,817 (2012)
Total Crude and Equivalent	Production (conventional, marketable bitumen and SCO, pentanes and condensates)	2.65 million bbl/d (2013)	2.45 million bbl/d (2012)
	Total crude oil deliveries	2.75 million bbl/d (2013)	2.57 million bbl/d (2012)
	* To the United States	73%	73%
	* Within Alberta	15%	16%
	* To rest of Canada	12%	11%
	* Offshore	0.2%	0.5%
Natural Gas and By-Product	Revenue	$1.10 billion	$0.95 billion
	Percentage of non-renewable resource revenue	12%	12%
	Average Alberta Gas Reference Price per Gigajoule (GJ)	$3.27/GJ	$2.29/GJ
	Number of conventional natural gas wells drilled	1,109 (2013)	983 (2012)
	Total marketable natural gas production including Coalbed Methane (CBM) in trillion cubic feet (Tcf)	3.5 Tcf (2013)	3.6 Tcf (2012)
	CBM production (excluding comingled gas)	0.27 Tcf (2013)	0.29 Tcf (2012)
	Total natural gas deliveries	4.2 Tcf (2013)	3.7 Tcf (2012)
	* To the United States	36%	38%
	* Within Alberta	36%	34%
	* To rest of Canada	28%	28%

Resource		2013-14	2012-13
Bonuses and sales of Crown Leases	Revenue from bonuses and sales of crown leases	$0.59 billion	$1.05 billion
	Revenue from rentals and fees	$0.17 billion	$0.18 billion
	Average price per hectare (ha) paid for petroleum and natural gas mineral rights	$327.52	$334.89
	Petroleum and natural gas hectares sold	1,792,294 ha	3,070,092 ha
	Average price per hectare paid for oil sands mineral rights	$248.44	$197.75
	Oil sands hectares sold	111,690 ha	131,668 ha
Freehold Mineral Tax	Revenue	$146 million	$119 million
Wells and Licences	Well Licences issued	9,894 (2013)	10,884 (2012)
	Industry drilling	5,367 (2013)	8,422 (2012)
Coal	Revenue	$16 million	-$2.7 million[1]
	Established coal reserves (estimate)	33.3 billion tonnes (2013)	33.3 billion tonnes (2012)
	Raw coal production	34.5 million tonnes (2013)	34.7 million tonnes (2012)
	Total marketable coal deliveries	28.3 million tonnes (2013)	28.3 million tonnes (2012)
	Percentage of total coal deliveries exported out of province	23% (2013)	22% (2012)
Electricity	Total generation capacity in Megawatts (MW)	14,598 MW (2013)	13,898 MW (2012)
	Total generation capacity from renewable sources	2,430 MW (2013)	2,427 MW (2012)
	Total generation capacity from coal	6,258 MW (2013)	5,690 MW (2012)
	Total generation of electricity in gigawatt hour (GWh)	76,005 GWh (2013)	72,918 GWh (2012)
	Amount of Alberta's electricity supplied by renewable resources	9.7% (2013)	9.7% (2012)
	Amount of Alberta's electricity supplied by natural gas	38% (2013)	37% (2012)
	Amount of Alberta's electricity supplied by coal	52% (2013)	52% (2012)
Metallic and Industrial Minerals	Revenue	$633,980	$684,759
	Hectares of mineral permits issued to exploration companies (LAMAS, MIM Permits and New Application Issued)	2.3 million hectares	968,963 hectares

Data sources: Alberta Utilities Commission, Department of Energy, Alberta Energy Regulator

Notes:

1 Coal revenues were reported as $13.3 million in this table in 2012-13. Net revenue for the fiscal year was negative $2.7 million due to a $16 million refund for production in the prior year.

Non-Renewable Resource Revenue

The Government of Alberta's non-renewable revenue forecasts are based on current conditions and factors, such as anticipated economic growth, non-renewable resource demand trends, and expected supply levels.

Forecasts and actuals can vary significantly based on world events, and supply and demand changes. For instance, global crude oil prices increased over the summer of 2013 as heightened geopolitical tensions, particularly in the Middle East and North Africa, altered supply and demand fundamentals. In addition, Canadian crude oil prices improved relative to international prices after the construction of new pipelines in the United States and the expansion of rail capacity transporting oil in Alberta. A weaker than anticipated Canadian dollar further resulted in higher crude oil and bitumen royalty revenues.

Although Alberta marketable natural gas production continued to decline, extremely cold temperatures and the weak Canadian dollar led to higher natural gas royalty revenues.

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

Revenue ($ Millions)	2013-14 Actual	2013-14 Budget
Bitumen	5,222	3,367
Crude oil	2,476	1,615
Natural gas & by-products	1,103	965
Bonuses and sales of Crown leases	588	1,148
Rentals & fees	173	145
Coal	16	10
Non-Renewable Resource Revenue	**9,578**	**7,250**

For **bitumen**, Budget 2013 was based on a US$92.50/barrel price for West Texas Intermediate (WTI) crude oil and a 99 cent Canada US exchange rate. The actual 2013-14 WTI price was US$99.05 based on an average of the monthly prices with a 94.98 cent exchange rate.

The forecasted light heavy differential was 27 per cent, giving a Western Canadian Select (WCS) price of C$68.21/barrel. The actual light heavy differential was 22.98 per cent and the WCS price averaged $80.11/barrel. The WCS price was higher than budgeted due to a lower than budgeted exchange rate, higher WTI price, and a lower than budgeted differential. The lower differential was due to production increasing less rapidly than expected and an increased use of rail transportation.

The budget for **crude oil** royalties was based on the same WTI forecast used for bitumen royalties.

WTI has historically been used as a North American benchmark in light sweet oil pricing and is reported in American dollars. Today, Brent is considered the benchmark world light sweet oil price.

WCS is blended bitumen that contains diluent. The price is quoted as a discount to WTI reflecting the lower refinery value.

The light heavy differential is the difference in value between light oils such as WTI and heavier oil like WCS. Light oil that is low in sulphur is more valuable to refiners than heavy oil with higher sulphur content.

Due to global supply disruptions 2013-14 oil prices were higher than budgeted every month after June, 2013. Additionally, conventional oil production averaged 582 thousand barrels per day in 2013-14 compared to the budgeted level of 550 thousand barrels per day. The increased production was the result of more horizontal oil wells being drilled and the high production rates associated with those wells.

The **natural gas and by-products** royalty in Budget 2013 was based on a gas price forecast of C$3.07/gigajoule for the Alberta natural gas reference price. The Alberta natural gas reference price averaged C$3.28/gigajoule in 2013-14. The colder than normal winter dramatically decreased storage levels of gas, especially in February and March of 2014; as a result, gas prices were higher than forecasted.

The forecast for **bonuses and sales of Crown leases** is based on oil and gas prices and production, industry revenue and cash flow, and the resulting expected sale price per hectare of Crown leases. The petroleum and natural gas average price per hectare was $327.52 compared to a Budget 2013 forecast of $424.13/hectare, and 885,631 fewer hectares than budgeted were sold. The oil sands sales totaled $28 million compared to a budget forecast of $9.5 million due to 73,288 more hectares being sold than predicted.

Rental and fees revenue was $28 million above budget due to more oil sands hectares being sold than expected, and additional petroleum and natural gas hectares being renewed than anticipated.

Bituminous **coal** royalty was higher than budgeted due to improved mine profitability.

RESULTS ANALYSIS

Review Engagement Report

To the Members of the Legislative Assembly

I have reviewed the performance measures identified as reviewed by the Office of the Auditor General in the Ministry of Energy's Annual Report 2013–2014. The reviewed performance measures are the responsibility of the ministry and are prepared based on the following criteria:

- Reliability—The information used in applying performance measure methodologies agrees with underlying source data for the current and prior years' results.
- Understandability—The performance measure methodologies and results are presented clearly.
- Comparability—The methodologies for performance measure preparation are applied consistently for the current and prior years' results.
- Completeness—The goals, performance measures and related targets match those included in the ministry's budget 2013.

My review was made in accordance with Canadian generally accepted standards for review engagements and, accordingly, consisted primarily of enquiry, analytical procedures and discussion related to information supplied to me by the ministry.

A review does not constitute an audit and, consequently, I do not express an audit opinion on the performance measures. Further, my review was not designed to assess the relevance and sufficiency of the reviewed performance measures in demonstrating ministry progress towards the related goals.

Based on my review, nothing has come to my attention that causes me to believe that the performance measures identified as reviewed by the Office of the Auditor General in the ministry's annual report 2013–2014 are not, in all material respects, presented in accordance with the criteria of reliability, understandability, comparability and completeness as described above.

Original signed by Merwan N. Saher, FCA
Auditor General

May 14, 2014
Edmonton, Alberta

Performance Measures Summary Table

Goals/Performance Measures		Prior Year's Results Actual				Target	Current
1.	**Albertans are assured of the benefits from energy and mineral resource development**						
1.a*	Combined tax and royalty rates for Alberta natural gas and conventional oil production, compared to similar jurisdictions[1]	-[2] (2008)	Alberta within first quartile (2009) 35.99%[r] (Natural Gas) 43.02% (Conventional Oil)	Alberta within first quartile (2010) 34.65%[r] (Natural Gas) 41.34% (Conventional Oil)	Alberta within first quartile (2011) 32.77%[r] (Natural Gas) 38.97% (Conventional Oil)	Alberta will have a combined tax and royalty rate that is in the top quartile of investment opportunities compared to similar jurisdictions	Alberta within first quartile[3] (2012) 28.19%[3] (Natural Gas) 36.60% (Conventional Oil)
1.b	Revenues from oil, oil sands, gas and land sale bonuses are fully collected: Percentage of amounts collected compared to amounts owed[4]	100% (2008)	100% (2009)	100% (2010)	100% (2011)	100%	100% (2012)
1.c	Alberta's oil sands supply share of global oil consumption	-[5] (2009)	1.8% (2010)	2.0% (2011)	2.1% (2012)	2.2%	2.3% (2013)
2.	**Effective stewardship of Alberta's energy resources and regulatory systems is achieved through leadership and engagement with citizens, communities, industry and governments**						
2.a	Albertans' assessment of their energy knowledge (biennial)	70% (2009)	n/a (2010)	63% (2011)	n/a (2012)	To maintain or increase the previous year's results.	64% (2013)
2.b*	Regulatory Noncompliance (AER/ERCB): Percentage of field inspections finding high risk regulatory noncompliance	1.7% (2009)	1.7% (2010)	3.2% (2011)	3.6% (2012)	Less than or equal to 3.0%	3.4% (2013)

Goals/Performance Measures		Prior Year's Results Actual				Target	Current
3.	**Development of energy related infrastructure and cleaner energy technologies is actively led and supported**						
3. a	Transmission Losses (%)	3.6% (2009)	3.8% (2010)	3.4% (2011)	2.9% (2012)	3.0%	2.9% (2013)
3.b*	Power generation: Margin (MW) between Firm Generating Capacity and Peak Demand[6]	18% (2009)	17% (2010)	12% (2011)	18% (2012)	Maintain a minimum 7% margin over peak load	18% (2013)
3.c	Timeliness of the Needs and Facility Applications (AUC): Percentage of needs and facility applications determined within 180 days of the application being deemed complete[7]	92% (2009)	100% (2010)	99% (2011)	93% (2012)	100%	96% (2013)

Notes:

r For the years 2009-11, the combined tax and royalty rates for Alberta natural gas are updated retroactively to reflect the revision in calculating Alberta's effective natural gas royalty rates. With the change, Alberta still remained within the first quartile of investment opportunities compared to similar jurisdictions.

1 The comparator jurisdictions include: British Columbia, Saskatchewan, California, Colorado, Louisiana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas, Utah, and Wyoming.

2 Performance measure 1.a was first introduced in the 2010-13 Business Plan. Results for this measure were not available for 2008 as Alberta's new royalty framework became effective January 1, 2009.

3 First quartile threshold: Natural gas, up to 50.48 per cent; conventional oil, up to 51.00 per cent.

4 Excludes disputed amounts.

5 Performance measure 1.c was first introduced in the 2012-15 Business Plan and the measure was introduced with current data and two years of historical data.

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

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.

7 The 2009 actual was revised from 98 per cent to 92 per cent to capture only needs and facility applications. The previously recorded results included applications for power plants and other minor facility applications, which do not have the 180 day legislative deadline.

* Indicates Performance Measures that have been reviewed by the Office of the Auditor General.

The performance measures indicated with an asterisk were selected for review by ministry management based on the following criteria established by government:

- Enduring measures that best represent the goal;
- Measures for which new data is available; and
- Measures that have well established methodology.

For more detailed information, see the "Performance Measure Methodologies" section in Appendix A.

GOAL ONE - Albertans are assured of the benefits from energy and mineral resource development

Energy royalties and land sale bonuses form an important part of the Government of Alberta's total revenue and help fund important government programs such as health care and education. The ministry reviews and maintains a royalty regime and ensures revenues are accurately calculated and fully collected.

Alberta maintains a competitive and effective royalty regime that attracts industry investment and provides jobs, business opportunities, tax revenue and numerous other benefits to provincial and national economies. Success is measured by sustaining vibrant industry activity and a fiscal regime that supports provincial services and infrastructure. Alberta's competitiveness is achieved by ensuring a competitive fiscal regime is maintained, energy transportation infrastructure is in place, supply costs are minimized and consumer market demand is sustained.

Adding value to raw resources is a high priority for Alberta. The province's world-class petrochemical industry, oil, gas, oil sands and minerals create significant potential for achieving additional benefits by upgrading resources into higher value commodities and products.

The Government of Alberta is working to build the province's reputation as a responsible energy producer with the aim of reaching new global markets and getting world prices for Alberta's resources. The *Building Alberta Plan* has identified opening new markets as key to the province's long-term prosperity.

As the United States' demand for Alberta's oil and gas is projected to level off, Alberta is looking to new Asian markets with increasing energy demand, such as India, South Korea, Japan and China. The potential for growing partnerships with Asian economies improves Alberta's ability to increase energy exports and attracts additional investment. It also provides Alberta with an opportunity to work together with other jurisdictions and stakeholders on common challenges.

Key Achievements

Increased Market Access for Alberta's Resources

The department explored opportunities to develop and expand Alberta's access to key global markets in 2013-14, initiating the province's first International Energy Strategy. This document draws on new in-house capacity and expertise, intelligence gathered from overseas, industry feedback to provide an overview of global supply and demand, infrastructure and geographic realities, and an approach for energy stakeholders in Alberta to engage the international community. The draft strategy will ensure purposeful forward movement in diversifying Alberta's trade in energy products, services and technologies and will articulate a role for government that supports Alberta energy business development in new markets outside North America.

> Alberta's international efforts have never been more fundamental to its future. This is why the Government of Alberta is committed to working with Albertans, industry and partners throughout the province and around the world to achieve more focused and active global engagement.

The Government of Alberta committed to conducting an oil market diversification campaign to tackle the most urgent challenges to gain market access and diversification for crude oil, inside and outside North America. The department led several missions to central and eastern Canada to meet with key stakeholders in other provinces. During these missions new or renewed relationships were initiated with other governments, port authorities, pipeline companies, industry associations, business community representatives and academia to promote oil market diversification to provinces across Canada. These missions helped to enhance joint awareness and understanding, build relationships, and provided information to address opportunities, issues and concerns around the diversification of Alberta's oil market.

The Government of Alberta is exploring all options - north, south, east and west - that advance the goal of diversifying markets and increasing access to tidewater. Alberta has products that world markets want, and the province is working to get energy products to those markets.

The British Columbia/Alberta Deputy Ministers Working Group was established to develop recommendations on how to open new markets, expand resource export opportunities, create jobs, enhance safety measures, and strengthen the economy of each province through the development of the oil and gas sector. The working group report released in January 2014 contains recommendations that are being addressed through continued bilateral engagement.

Engagement with stakeholders in provinces east of Alberta promoted increased market access for Alberta's oil in eastern Canada. The department was active through missions in Manitoba, New Brunswick, Ontario, Quebec, and Saskatchewan.

In collaboration with other ministries, the department supported the government's advocacy efforts in the United States to build awareness and share expertise and experience, with an emphasis on the responsible regulation and management of Alberta's resource development. This effort included participating in both incoming and outgoing missions with business leaders, financial institutions, foreign government officials, academics and media. The purpose of these missions was to share information and provide fact-based evidence about Alberta's resource development, and engage organizations in other jurisdictions with an interest in Alberta's resources and environmental performance.

Asian Market Collaboration

In 2013-14, the department expanded energy-related collaboration to secure market access opportunities by formalizing and consolidating new energy relationships in Asia. This effort is reflected in the groundbreaking Framework Agreement on Sustainable Energy Development signed with the National Energy Administration of China. Additional agreements were developed in Japan and Korea, and an entry-level Expression of Intent to Collaborate was signed by the Alberta Petroleum Marketing Commission (APMC) and the Indian Oil Corporation. These agreements take Alberta one step forward to energy trade relationships in east and south Asia by ensuring over-arching political endorsement, and by creating multiple pathways for trade in energy products, services, and expertise.

Canadian Energy Strategy

Alberta supports the development of the Canadian Energy Strategy (CES), which is a national collaborative approach to energy development that positions Canada internationally. It will further contribute to increased security, stability and equitable access to energy for all Canadians. The CES will position Canada as a global leader in social and environmentally responsible energy development.

The commitment to developing the CES resulted from a renewed focus on energy by premiers across Canada in July 2012 at the Council of Federation (COF) meeting. The Canadian Energy Strategy Secretariat was established by the Government of Alberta to lead the coordination of the development of the CES with the Co-Chair provinces and jurisdictions across the country.

The CES continues to be developed based on expertise, research and stakeholder feedback from across Canada. A successful national CES Stakeholder Engagement Workshop involving 100 participants was held in Edmonton, Alberta, in June 2013. Open dialogue and collaboration continues to occur among the provinces and territories to ensure that a broad range of views, energy needs and priorities are reflected in the strategy. A CES Progress Report was approved and released at the COF meeting in July 2013 identifying the vision and principles, activities undertaken by provinces and territories since 2007, and potential challenges and opportunities facing Canada's energy sector. The CES will be completed and submitted to the COF in preparation for their meeting in August 2014.

Energy Investment Competitiveness

Alberta maintains a competitive and effective royalty framework that encourages responsible resource development, provides a favourable climate for industry growth and maximizes benefits to Albertans. Alberta has attracted industry investment with a combined tax and royalty rate that is in the top quartile of investment opportunities compared to similar jurisdictions in North America, while assuring that Albertans collect an appropriate return from resource development.

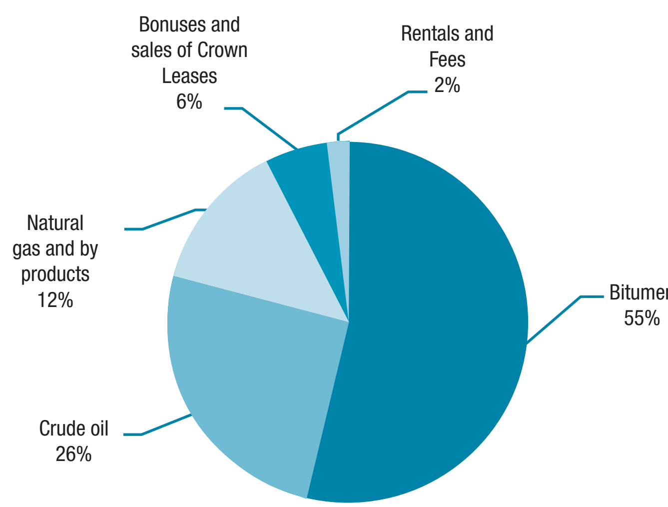
As a province with significant natural resource endowments, Alberta competes for investment with other resource-rich jurisdictions to ensure continuous development of its energy industry. Alberta provides a stable political environment and favourable business climate, which is attractive to investors and conducive to responsible development of Alberta's non-renewable resources. In 2012, at a total of $51.94 billion, capital expenditure in Alberta's upstream oil and gas industry was the highest ever in the province's history which is a positive reflection on Alberta's ability to attract investment. This represented an increase of about 16 per cent from 2011. Alberta's success in attracting investors is evidenced by the fact that capital expenditure in Alberta's oil sands reached an all-time high of $27.15 billion in 2012. Conventional oil and gas capital expenditure in 2012 reached $24.79 billion, the second highest level ever.

Non-Renewable Resource Revenue Collection and Record Production

Non-renewable resource revenues provide vital contributions to Alberta's provincial budget.

Among the sources of non-renewable resource revenue, for the fifth fiscal year in a row, bitumen royalty will make the largest contribution to provincial royalty revenue. In 2013-14, bitumen accounted for about $5.2 billion, or about 55 per cent of the forecasted non-renewable resource revenue of $9.6 billion.

The relative strength of the oil sands industry is reflected by the fact that annual crude bitumen production has been increasing since 2008. In 2013, crude bitumen production in Alberta reached its highest level ever, at about 2.1 million barrels per day (bbl/d). This marked the first calendar year during which total annual crude bitumen production exceeded two million bbl/d.



Total non-renewable resource revenue 2013-14: $9.6 billion

Note: Percents do not add up exactly due to rounding.

Conventional crude oil royalties contributed about $2.5 billion to provincial revenue in 2013-14, the second highest resource revenue source. The third largest source of resource revenue was natural gas and by-products royalties, which brought in approximately $1.1 billion. In 2013-14, a total of 3,089 petroleum and natural gas agreements were issued for a total bonus of over $588 million on over 1.79 million hectares. The average price per hectare was $327.52. The March 5, 2014 sale brought in the highest bonus at over $70 million with an average price of $768.68 per hectare.

In 2013-14, a total of 117 oil sands agreements were issued for a total bonus of almost $28 million covering 111,690 hectares. The average price per hectare was $248.44. The September 25, 2013 sale brought in the highest bonus, which was over $10 million with an average price of $599.90 per hectare. This represented an increase from the previous year, which is partially due to the signing of a Co-Management Agreement between the ministry and the Métis Settlements General Council. In 2013-14, the Co-Management Agreement has enabled Industry to lease Crown mineral rights located beneath the lands of five Métis Settlements within the oil sands region.

Under the Co-Management agreement, Métis Settlements will have the authority to require companies bidding on resource rights beneath settlement lands to submit benefits proposals in areas, such as local employment, training or infrastructure improvements. The benefits proposals will be submitted to the settlement council as part of a final selection process. Alternatively, a company wholly owned by a settlement council may choose to directly purchase the rights under its land at a pre-set price.

The department's information management and technology infrastructure, business systems, security and processes continue to ensure accurate, timely and effective resource revenue assessment and collection for Albertans. New and improved business processes, and information management and technology solutions are implemented to meet emerging business priorities and to support essential business operations.

Energy Processing and Petrochemical Developments

As stewards of our energy resources, the Government of Alberta continues to support the production of higher value energy products from raw resources. Working with industry and other stakeholders, the government facilitated multiple market solutions across and down the energy value chain to generate sustainable, long-term benefits for present and future generations of Albertans.

The Incremental Ethane Extraction Program (IEEP) is a $350 million program that encourages increased petrochemical production in Alberta by providing incentives through royalty credits to help offset the high capital costs of recovering incremental barrels of ethane feedstock. Eight Annual Eligibility Applications were received during the 2013 calendar year. The IEEP is now fully designated and will facilitate production of approximately 92,000 bbl/d of ethane. To date, more than $2 billion in new capital investments by industry has occurred as a result of IEEP.

The Standing Committee on Alberta's Economic Future published a report in May 2013 recommending that the ministry continue to implement Bitumen Royalty-in-Kind (BRIK) programs to promote value-added petrochemical processing in Alberta and leverage the environmental and economic benefits of planned Carbon Capture and Storage infrastructure, wherever possible. The ministry continues to move forward with this policy on a project-by-project basis, and is including opportunities to use BRIK to promote access to new markets.

Construction of the North West Redwater Partnership's Sturgeon Refinery commenced. The APMC will supply 37,500 bbl/d of bitumen (and diluent) from the BRIK program for 30 years, which is roughly 75 per cent of the refinery's capacity. The refinery will primarily produce diesel fuel and diluent beginning in mid-2017, and feed carbon dioxide from its processes into the Alberta Carbon Trunk Line, a commercial-scale carbon capture and storage initiative.

The government is continuing to review options to increase the amount of downstream gas processing completed in Alberta. Departments are collaborating to understand how to support energy value chain opportunities through new product development, new markets and made-in-Alberta technologies to make the province a more competitive destination for investment capital by the downstream energy processing sector.

As the resource owner, the Government of Alberta is entitled to take its royalty share of bitumen production in kind, as it does for conventional oil production. The Government's bitumen royalty volumes will be a significant and growing source of reliable hydrocarbon feedstock into the future. The APMC is responsible for marketing the conventional oil and bitumen that government receives in lieu of cash royalties and for implementing the BRIK policy.

Performance Measure 1.a: Combined tax and royalty rates for Alberta natural gas and conventional oil production, compared to similar jurisdictions

Target

Alberta will have a combined tax and royalty rate that is in the top quartile of investment opportunities compared to similar jurisdictions.

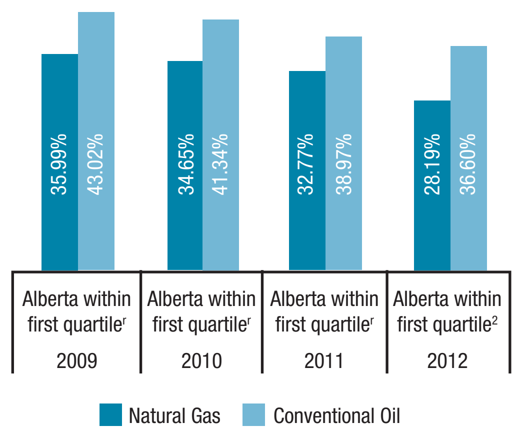
Discussion of Results

This indicator will enable the Government of Alberta to monitor and evaluate whether or not Alberta has a competitive royalty regime in place to attract industry investment, and to determine if the appropriate shares of royalty revenue are being collected from the development of these resources on behalf of Albertans.

During 2010, the Government of Alberta unveiled a number of initiatives to address the long-term competiveness of Alberta's natural gas and conventional oil sectors. Conventional oil and natural gas royalty rates were modified to encourage innovation and to promote the use of new technologies. The Regulatory Enhancement Project was undertaken to streamline the oil and gas policy and regulatory systems. These changes were deemed necessary to address the new reality of increased supply competition from unconventional resources (e.g., shale gas and tight oil) located near Alberta's traditional export markets in eastern Canada and the United States.

Figure 1.a

Combined tax and royalty rates for Alberta natural gas and conventional oil production compared to similar jurisdictions.[1]



Source: Department of Energy.

Notes:

r For the years 2009-2011, the combined tax and royalty rates for Alberta natural gas are updated retroactively to reflect the revision in calculating Alberta's effective natural gas royalty rates. With the change, Alberta still remained within the first quartile of investment opportunities compared to similar jurisdictions.

1 The comparator jurisdictions include: British Columbia, Saskatchewan, California, Colorado, Louisiana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas, Utah, and Wyoming.

2 For 2012, the first quartile threshold for natural gas was up to 50.48 per cent. For conventional oil, it was up to 51.00 per cent.

With a focus on unconventional oil and liquids-rich gas resources in Alberta, both land sales and drilling activity rebounded significantly from 2009 levels. When compared to other Western Canadian provinces, Alberta regained its dominant position in its petroleum and natural gas land sales in 2010 and has since maintained its top position in bonus revenue. Starting in 2011, Alberta conventional oil production also reversed the downward trend related to a number of factors, including the adjustments in Alberta's royalty regime in 2010, the advent of tight oil and increased activity of horizontal drilling and multi-stage hydraulic fracturing. From 2012 to 2013, Alberta experienced production growth of 4.7 per cent for conventional oil on a barrel-per-day basis.

In 2012, Alberta remained within the first quartile (top three) (along with British Columbia and Saskatchewan) of investment opportunities compared to similar jurisdictions based on the combined tax and royalty rates for natural gas and conventional oil.

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

Target

100 per cent of amounts owed are collected.

Discussion of Results

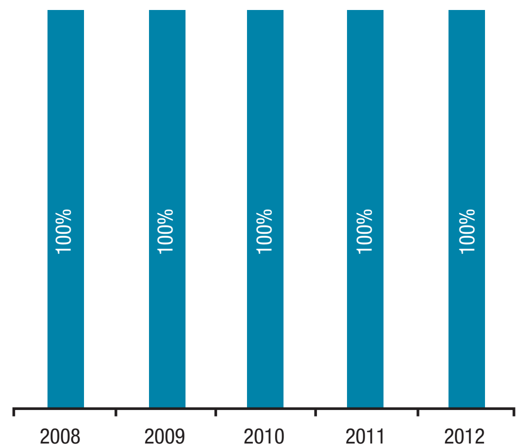
The department collects the Crown's share of energy resource development on behalf of Albertans. This measure gauges the ability of the department to collect the amounts owed from the development of Alberta's energy resources.

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

The results reported in this measure are based on financial obligations over which there are no disputes between the Government of Alberta and entities that owe funds to the government.

Figure 1.b

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



Source: Alberta Petroleum Marketing Commission; Department of Energy.

Notes: Excludes disputed amounts.

In case of disputes over funds owed to the government, the disputed amounts are excluded from the results until all outstanding matters are resolved. Upon resolution, historical results are reviewed, and if necessary, retroactively adjusted.

In 2012, all amounts have been collected or are in the process of being collected, and no write-offs were made. In 2012, the result was 100 per cent, as in the previous four years for which the results are reported in this Annual Report.

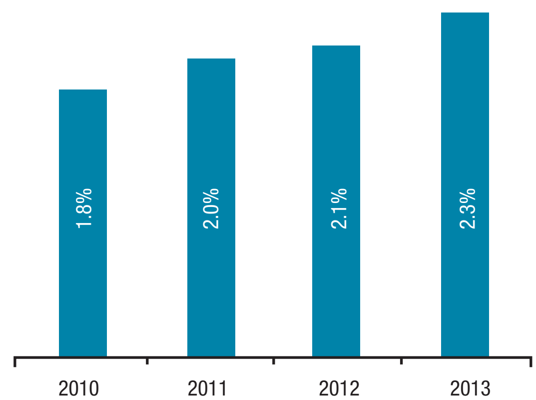
Performance Measure 1.c: Alberta's oil sands supply share of global oil consumption

Target

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

Figure 1.c

Alberta's oil sands supply share of global oil consumption.



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

Discussion of Results

This performance measure was introduced for the first time in the 2012-15 Energy Business Plan. This is the second Annual Report to present the results of this measure.

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

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

Alberta's oil sands supply share of global oil consumption increased over the examined period from 2.0 per cent in 2011, to 2.1 per cent in 2012 and to 2.3 per cent in 2013. The target for 2013, 2.2 per cent, was exceeded by 0.1 per cent. The increase in Alberta's share was primarily driven by increases in total oil sands production in Alberta, rather than disruptions in global oil demand. From 2011 to 2012, oil sands production increased by 10 per cent, from about 1.74 million barrels of oil per day (bbl/d) in 2011 to about 1.92 million bbl/d in 2012. Alberta oil sands production further increased to about 2.09 million bbl/d in 2013, a nine per cent increase compared to 2012.

GOAL TWO - Effective stewardship of Alberta's energy resources and regulatory systems is achieved through leadership and engagement with citizens, communities, industry and governments

The ministry is actively working with partner ministries and stakeholders to develop and implement the Integrated Resource Management System (IRMS). The IRMS is a big-picture approach that considers the overall environmental, economic, and social outcomes of resource development. This system ensures that the province takes a coordinated approach that examines all parts of resource development, promoting responsible resource and environmental stewardship. In doing so, the ministry supports a range of activities, from habitat protection to action on climate change, clean energy technologies, and the creation of the Alberta Energy Regulator (AER). This contribution will aid the province in achieving the social, economic and environmental outcomes Albertans want from resource development.

In support of the IRMS, the ministry has worked closely with Albertans, communities, governments and industries to develop strategic and integrated policies and plans for sustainable energy and mineral development. IRMS includes working with other ministries to further develop regional plans and air, water, and biodiversity frameworks that consider the cumulative effects of land-use activities.

The department invests in advances for energy efficiency and conservation to mitigate rising energy costs and environmental impacts, and to reduce energy requirements within the province.

The ministry will continue to regulate Alberta's energy industry to ensure the efficient, safe, orderly, and environmentally-responsible development and sustainable management of energy and mineral resources. The Government of Alberta has established, in legislation and policy, a regulatory framework intended to ensure that the discovery, development and delivery of Alberta's energy resources and the development of Alberta's utility system take place in a manner that is fair, responsible and in the public interest.

Key Achievements

Regulatory Enhancement Project and *Responsible Energy Development Act*

The Policy Management Office (PMO), with joint reporting to both the Minister of Environment and Sustainable Resource Development (ESRD) and the Minister of Energy, was formally established in September 2012 to ensure the integration of natural resource policies and to serve as an interface between policy development and policy assurance.

The PMO implements and maintains policy integration and development by providing a clear engagement process during the policy development and assurance stages, ensuring a common risk assessment and management approach, and adopting a performance measurement framework. Since its inception, the PMO has been working with its partners on the implementation of the Regulatory Enhancement Project recommendations, which included the establishment of the AER as a single regulatory body for upstream oil and gas, oil sands, and coal development activities.

The AER began operations in June 2013. Since its launch, the AER has transitioned into the single, full-life-cycle energy regulator for Alberta. The transition took place in three phases. Each phase saw the AER assume new functions and responsibilities related to energy resource development that were previously held by ESRD. In November 2013, ESRD transitioned specified functions under the *Public Lands Act* and the *Mines and Minerals Act* to the AER. Another transition occurred in March 2014, enabling the AER to assume functions under the *Water Act* and the *Environmental Protection* and *Enhancement Act.* These new functions fully authorize the AER to protect land, water, and air.

In 2013-14, the AER worked closely with the Aboriginal Consultation Office (ACO) to define the alignment between the consultation and regulatory processes in Alberta, which support the direction of the ACO. This collaborative relationship creates an operational-level connection between the AER and ACO, and ensures the requirements of Ministerial Order 141/2013 will be met.

Ministerial Order 141/2013 provides direction to ensure that the AER considers and makes decisions in respect of energy applications in a manner that is consistent with the work of the Government of Alberta in meeting its consultation obligations associated with the existing rights of Aboriginal people. The Order gives eight specific directions to the AER and sets up a process on Aboriginal consultation that the AER must follow.

Protecting our Natural Habitats with Regional Planning

The Lower Athabasca Regional Plan (LARP), the first of seven regional plans across the province, came into force in September 2012. It 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. In 2013-14, to achieve the management intent of the new conservation and provincial recreation areas, the department cancelled 76 oil sands and metallic and industrial minerals leases, or portions, which fell within the boundaries of the new protected areas.

The draft South Saskatchewan Regional Plan (SSRP) was released for public and stakeholder consultation in October 2013. The department actively participated in the public and stakeholder consultation sessions and is a key member of the cross-ministry team involved in finalising the regional plan. All submissions and feedback received during the public consultation process will be fully considered by the government in drafting the final SSRP. The draft SSRP addresses key issues, such as the establishment of new conservation areas for the protection of headwaters and water security, species-at-risk management, and management of recreation, to balance environmental and social values with development. The work completed provides clear outcomes and management frameworks with thresholds to allow timely policy decisions by government and other regulatory decisions by the AER. These measures will increase certainty for industry for access to subsurface resources.

The department continues to be a key member of the cross-ministry Land-use Framework Integration Team to ensure the Energy story is clearly articulated in the regional planning process and to ensure continued collaboration with ESRD and other ministries, such as Agriculture, Tourism, Parks and Recreation, Municipal Affairs, Transportation, and Innovation and Advanced Education.

Preparatory work continued for the remaining regional plans, with the North Saskatchewan Regional Plan (NSRP) the priority. The department provided technical analysis of energy and mineral resources 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. The Call for Nominations for the Regional Advisory Council for the NSRP was released publicly in March 2014. The Terms of Reference for the NSRP will be released for consultation once approved by Cabinet. The Upper and Lower Peace Regional Plans are in the initial planning stages.

Integrated Infrastructure Planning in Oil Sands Areas

Comprehensive Regional Infrastructure Sustainability Plans (CRISPs) provide a long-term, flexible and integrated approach to planning for growth in the oil sands areas. The plans require coordination among the Government of Alberta, municipalities, industry and other key stakeholders. They are built to increase the quality of life for Albertans by focusing on the development of infrastructure needed to support continued quality of life and oil sands development in Alberta's three oil sands regions.

In 2013-14, work continued on the Athabasca Oil Sands Area CRISP. Road and aviation transportation priorities were identified and support was provided to several key stakeholder groups involved in the development of transportation infrastructure and planning for continued community growth. A major focus was the establishment of the Fort McMurray Urban Development Sub-Region (UDSR), which was announced in July 2013. The UDSR identifies over 55,000 acres of Crown land for future urban expansion.

The Cold Lake Oil Sands Area CRISP was publicly released in April 2014 and is currently being implemented through the work of issue-specific teams in the areas of transportation, accommodations and aviation.

In 2013-14 the department worked with several provincial ministries and regional stakeholders to develop the initial draft of the Peace River Oil Sands Area (PROSA) CRISP. The PROSA CRISP is expected to be completed in 2014-15.

Enhance Albertans' Energy Knowledge

The Government of Alberta's long-term vision for sustainable energy development in the province identifies the need to help Albertans increase their knowledge and awareness about Alberta's energy resources and how these resources contribute to the province's economy and prosperity. The government continues to lay this foundation. In 2013-14, the department provided grant funding to fact-based energy literacy providers, and participated in pan-Canadian forums that worked to advance increased energy literacy, awareness and information. The intent is to increase knowledge of and interest in Alberta's energy sector, so that Albertans and Canadians can critically assess energy information and better understand how it relates to and impacts their lives.

Energy Efficiency and Sustainability

In 2011, the Premier issued a mandate to four departments to implement initiatives to make Alberta a national leader in energy efficiency and sustainability. In 2013-14, the department continued to work with ESRD and other ministries to explore opportunities for incentives and policy approaches to increase energy efficiency and the production and consumption of low-emission, alternative and renewable energy for electricity, heat and transportation end-uses. In 2013-14, some of the initiatives included:

- participation in the development of an energy efficiency policy framework and actions under review and renewal of the Climate Change Strategy led by ESRD;
- participation in the development of an Alternative and Renewable Energy Policy Framework in coordination with the Climate Change Strategy review;
- identification of energy efficiency as one of the focus areas in the development of the Canadian Energy Strategy; and
- ongoing work with Natural Resources Canada, other Government of Alberta ministries, and stakeholders on natural gas vehicles.

High Standards of Public Safety, Environmental Protection and Energy Resource Development

In 2013-14, the AER launched the Incident Reporting Tool on its website. This initiative demonstrates the AER's commitment to transparency, as the tool helps ensure Albertans are better informed about energy incidents in the province. The incidents posted meet the following criteria: any reportable release that involves hydrogen sulphide; any reportable release that affects a water body; and any reportable release of hydrocarbon or produced water. The tool is searchable, printable and updated daily.

The Licensee Liability Rating (LLR) program protects Albertans and the orphan fund from the costs associated with abandonment and reclamation of upstream oil and gas wells, facilities and pipelines. It results in higher compliance by requiring licensees to pay a financial security that covers the costs of abandonment and reclamation, should operations fail. In 2014, the LLR Program Management Plan was created to complement the LLR program. Under the LLR Program Management Plan, companies receive flexible payment timelines in exchange for a higher level of scrutiny of their finances and ability to meet security requirements.

The AER completed a review of the challenges and opportunities related to development of Alberta's unconventional oil and gas resources. From its review, the AER defined a new regulatory framework for unconventional oil and gas intended to enhance the current system to ensure risks to conservation, public safety, and the environment are considered and mitigated. The new framework was implemented by releasing a new directive on hydraulic fracturing, enhancing existing directives, and designing a pilot project to test the new framework in an area of concentrated resource development. As technology evolves, the AER will continue to review and update its rules based on emerging issues, risks, opportunities, and challenges.

In 2013, the AER responded to the Alberta Pipeline Safety Review by accepting all 17 recommendations made by the independent review panel.

In 2012, the Minister of Energy directed the AER to conduct a third-party pipeline safety review. Group 10 Engineering Ltd. conducted the review and made 17 recommendations to enhance an existing strong and extensive Alberta pipeline regulatory system.

Pursuant to the *Responsible Energy Development Act*, in March 2014 the AER released its report on the proceeding into examining odours and emissions associated with heavy oil operations in the Peace River area. This issue and the proceeding have attracted significant attention from the public, media, government, and industry.

During 2013-14, the AER provided regulatory oversight to Alberta's more than 415,000 km of pipeline, and conducted more than 1,300 pipeline construction and operation inspections. As a result, 217 pipelines were considered to be in high-risk noncompliance and 37 were ordered to suspend operations.

In March 2014, the AER released its incident investigation report detailing the Plains Midstream Canada Ltd. Rangeland pipeline failure that occurred in June 2012. As the full-life-cycle energy regulator for Alberta, the AER is making changes to its investigation procedures. The changes will provide more timely completion and reporting on the details of incidents and the AER's findings.

Responsible Regulation of Alberta's Utilities

In 2013-14, the Alberta Utilities Commission (AUC) continued to make timely decisions on regulated utility rates, and electricity and natural gas transmission and distribution facilities, which are needed to attract investment, meet future needs and ensure fair pricing.

The AUC continued to utilize an enhanced process to conduct public hearings on several regional transmission development projects, including the Foothills, Fort McMurray and St. Paul areas. In the Foothills area transmission development decision, the AUC utilized landowner-generated route selections, which were found to be in the public interest and superior to other potential routes. These route selections took into account concerns about environmental and agricultural impacts.

The AUC initiated a proceeding to address the multi-year and multi-phase project involving high-pressure gas utility pipelines. The urban pipeline replacement (UPR) project seeks to replace some existing high-pressure gas pipelines, or where designated, convert to low-pressure distribution service within Edmonton and Calgary, and build new high-pressure gas pipelines in and around the transportation and utility corridors. In its decision, the AUC found that the UPR application is in the public interest, as it will result in Edmonton and Calgary systems that are safe, economic, orderly and efficient.

The AUC concluded an integrity management and emergency response review of gas utility pipelines in Alberta that fall under the AUC's jurisdiction. In its findings, the AUC identified opportunities for improvement and is assessing further activities to ensure the ongoing safety of the pipeline systems it oversees.

The AUC completed the next stage of the rate regulation initiative to reform utility rate setting in Alberta by issuing a decision on the treatment of capital costs for distribution companies under the performance-based regulation (PBR) rate-setting framework. These capital costs for projects will be tracked through a capital tracker mechanism and will be trued up to actual costs following a prudence review upon completion of the capital tracker project. The PBR framework provides an alternative to the traditional cost-of-service regulatory framework and provides incentives for efficiency resulting in cost savings or other benefits to be allocated between a company and its customers.

Improved Regulatory Processes for Select Utilities Applications

In 2013-14, the AUC continued to enhance regulatory processes to introduce shorter application cycles and to reduce regulatory burden through the elimination of routine, low-risk applications.

The AUC led changes to the Hydro and Electric Energy Regulation to effectively eliminate the application requirements for small power plants generating less than one megawatt, provided that the owners satisfy certain public interest requirements. This new exemption streamlines the process for all small power plant owners, including micro-generation.

The AUC approved revisions to its wind-power application requirements, which are intended to improve the application process and provide flexibility to applicants for wind power generation developments. These revisions will bring clarity and certainty to potential investors. A key focus for power generation developers is to maintain flexibility when acquiring the best available equipment in response to rapid technological improvements. Developers indicated a desire to delay identifying the specific equipment and the selection of vendors during the initial phase of the application process. The revisions to the wind-power application requirements facilitate these concerns and provide a more efficient process for wind-power generation development.

The AUC continued to streamline the notification process by developing protocols to ensure potentially affected Albertans have a variety of opportunities to provide input into the public review process. Also, to better understand what information should be included in a public notice, the AUC consulted with rural and urban Albertans to ensure that meaningful information is provided to potentially affected Albertans in a timely manner.

Performance Measure 2.a: Albertans' assessment of their energy knowledge

Target

To maintain or increase the previous year's results.

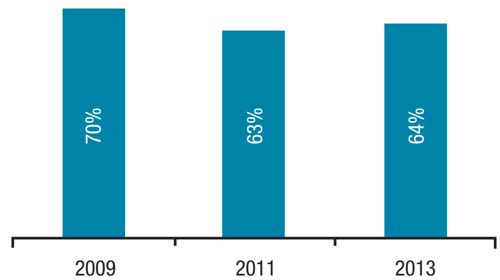
Discussion of Results

The Government of Alberta's long-term vision for sustainable energy development in the province identifies the need for Albertans to increase their knowledge and awareness about Alberta's energy resources and how these resources contribute to Alberta's economy and prosperity.

Through a biennial survey, this performance measure tracks Albertans' assessments of their knowledge of energy. The most recent survey was conducted in the summer of 2013. Of the participants surveyed, 64 per cent believe that they are knowledgeable about the energy industry in Alberta. This is an improvement of one per cent from the previous survey in 2011 and is consistent with the target to maintain or increase the previous year's results.

Figure 2.a

Albertans' assessment of their energy knowledge (biennial survey).



Source: 2013 Omni Alberta Survey.

The ministry continues to lay the foundation to enhance Albertans' energy knowledge. Some examples include providing grant funding to fact-based energy literacy providers; and participating in pan-Canadian forums that advance energy literacy, awareness and information.

Performance Measure 2.b: Regulatory noncompliance

Target

Less than or equal to three per cent of field inspections finding high risk regulatory noncompliance.

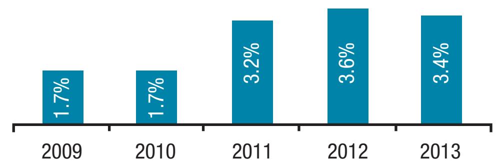
Discussion of Results

High-risk noncompliance is when a contravention of regulation(s) or requirement(s) is found that the licensee has failed to address and/or that has the potential to cause a significant impact on the public and/or environment and/or resource conservation.

This performance measure helps indicate industry's compliance with regulatory requirements. In calendar year 2013, the AER conducted 12,367 initial inspections, investigations, and odour investigations were conducted. This is a slight decrease of 114 (just under one per cent) from 2012. As a result of these inspections, 420 high-risk non-compliances were discovered of which 217 were related to pipelines.

Figure 2.b

Percentage of field inspections finding high risk regulatory noncompliance.



Source: Field Surveillance Inspection System database and Alberta Energy Regulator Waste Facility Spreadsheet, March 2014.

Year	Number of high risk regulatory noncompliance inspections	Total number of inspections	Percentage of field inspections finding high risk regulatory noncompliance
2013	420	12,367	3.4%
2012	447	12,481	3.6%

The 2013 result was 0.4 per cent above the 2013-16 Business Plan's target of three per cent. The target has been established based on historical data and is the expected percentage of field inspections finding high-risk regulatory noncompliance. The target was established prior to 2011 when the organization adopted the use of an Integrated Risk Management framework. This risk management tool was integrated into the AER's field inspections over the past year – with inspectors focusing on higher risk, higher value inspections, as determined by the Field Operations Technical Specialists in each inspection discipline and by the Team Leaders in each Field Centre area. The percentage of field inspections finding high-risk regulatory noncompliance is driven by both the number of high-risk noncompliance inspections and the total number of initial inspections. The reduction in the total number of inspections and the decrease in the number of high-risk regulatory noncompliance inspections led to a lower percentage of field inspections finding high-risk regulatory noncompliance in 2013.

The selection of a sample of operations for inspections is based on both internally defined risk criteria and external factors, such as incidents and complaints.

In 2013 there were several significant external incidents that impacted the selection of operations for inspections, which included two major pipeline breaks. Operations in these areas were targeted through inspections which resulted in a greater number of high-risk noncompliance inspections (174 in 2012, 217 in 2013).

The AER works with industry on the prevention of regulatory noncompliance. To ensure that industry operations staff better understand regulatory requirements, the AER continues to educate industry through targeted presentations and operator awareness sessions.

GOAL THREE - Development of energy related infrastructure and cleaner energy technologies is actively led and supported

Alberta's electricity system requires a transmission system with capacity to meet increasing demand. Natural gas and oil pipelines are needed to access new markets and infrastructure is needed to support carbon capture and storage (CCS) technology. The ministry works with other ministries and stakeholders to encourage development of energy infrastructure and broader social/community infrastructure in support of future economic prosperity.

Reliable and efficient energy markets are vital to the social and economic foundation of Alberta. Through policy and market design for wholesale and retail electricity and natural gas markets, reliable energy supplies and competitive prices for Alberta consumers are assured.

The Government of Alberta has established, in legislation and policy, a regulatory framework intended to ensure that the discovery, development and delivery of Alberta's energy resources, and the development of Alberta's utility system, take place in a manner that is fair, responsible and in the public interest.

To address the needs of electricity consumers, the ministry has implemented increased scrutiny of transmission costs and reduced volatility in Albertans' month-to-month electricity prices. The ministry also provides policy guidance for Alberta's fair, efficient and openly-competitive electricity market.

The use of new technologies in energy production is helping to reduce environmental impact. Beyond the advances in alternative and renewable energy sources, innovations are also enabling the province's energy resources to be extracted and upgraded with fewer emissions and by using less water or electricity. Through CCS, carbon dioxide from emissions will be used to increase the amount of resources extracted through existing wells. Government has partnered with researchers and industry to further the use of new technologies and methods.

Key Achievements

Supporting the Reduction of Greenhouse Gas Emissions
Alberta is committed to being a responsible global energy supplier and a leader in greenhouse gas (GHG) reduction technology. The Government of Alberta is renewing the Climate Change Strategy and associated regulations to make sure they continue to be effective and innovative in reducing emissions at the source.

Alberta has been participating with other provinces and territories as well as industry in the federal government's sector-based tables to establish national GHG performance standards. During 2013-14, Environment Canada proposed to regulate GHG emissions from natural gas-fired turbines and boilers in the electricity sector. The department continued to provide technical analysis and electricity policy support to Environment and Sustainable Resource Development (ESRD) as they liaise with Environment Canada to evaluate policy options which achieve emission reduction targets while not unduly impacting electricity ratepayers. The department continued to work closely with ESRD to ensure that the Natural-Gas Fired Electricity Emissions Regulation harmonizes with the Coal-Fired Electricity Emissions Reduction Regulation that is expected to come into force in 2015.

The department also worked with ESRD on a review of the GHG regulation related to the oil and gas sector, by providing technical and policy support.

Implementation of the Recommendations of the Retail Market Review Committee

In 2012, the Retail Market Review Committee (RMRC) was established to review the default rate in context of the retail market and determine ways of reducing the volatility of the default rate for electricity. The committee's report had 41 recommendations, 35 of which the government accepted and two of which were implemented. In addition, the MLA RMRC Implementation Team (RIT) was appointed to review 33 recommendations. The MLA RIT worked with stakeholders to examine ways to increase competitiveness, represent consumers' interests, provide better information for consumers, as well as protect vulnerable Albertans and the default rate.

> In 2012, the premier announced a four-point plan to address the volatility and costs associated with electricity. The plan called for an independent review of the default rate option in order to reduce electricity volatility and costs for consumers. The RMRC was established as a result to analyze the default rate and determine if it was still needed, and if so, how it should be designed and delivered, and what its purpose should be.

In discussions with stakeholders such as consumer groups, industry, agencies and rural electrification associations, the MLA RIT sought to understand both the concerns identified by the authors of the RMRC report and the implementation challenges anticipated in the market. Stakeholder working groups were established to discuss consumer education, governance, regulatory, rural electric utility role clarity and vulnerable Albertans. Over 100 stakeholders were invited to participate at the working group level, resulting in dynamic discussions on individual recommendations.

Each working group submitted their implementation options with advice to the MLA RIT, which is expected to develop its own recommendations and submit its final report in 2014.

World Class Carbon Capture and Storage

The Government of Alberta's CCS program balances the economic benefits the province receives from the development of its resources with the responsibility of reducing greenhouse gas emissions. Through the CCS funding program, Alberta has committed a total of $1.3 billion over 15 years to fund two large-scale CCS projects, the Alberta Carbon Trunk Line and the Quest project. Both projects, anticipated to come on line in 2015, will store 2.76 million tonnes of carbon dioxide per year. These projects represent two of the world's 21 CCS projects.

> The Quest project will retrofit Shell's Scotford upgrader located near Fort Saskatchewan for CCS. Quest will permanently store captured carbon dioxide more than two kilometres below surface. The Alberta Carbon Trunk Line is a 240 km pipeline that will transport carbon dioxide emissions captured in Alberta's Industrial Heartland. The transported carbon dioxide will be used for enhanced oil recovery.

Under the CCS funding program, approved projects receive funding after specific project milestones are met and verified by the department. In 2013-14, the department successfully certified two construction milestones for the Quest project and administered installment payments under the funding program.

During the same time period, the CCS Regulatory Framework Assessment examined the technical, environmental, safety, monitoring, and closure requirements for CCS. The assessment process involved over 100 national and international stakeholders and experts from industry, government, academia, research institutions, and non-governmental organizations. The final report from the assessment was released in August 2013 and included 71 recommendations for a world-class regulatory framework for commercial scale CCS operations in Alberta. The Government of Alberta is continuing to work with stakeholders to review all 71 recommendations from the assessment over the next three years.

The Government of Alberta is further committed to knowledge sharing and advocacy of the CCS program to support greater deployment of CCS technologies globally and to demonstrate that Alberta is a responsible energy producer. In 2013 the department launched a knowledge-sharing webpage. The website includes reports from the Quest and Alberta Carbon Trunk Line projects, along with the CCS Funding Agreements. In addition, the Government of Alberta held two working sessions with the Norwegian Government to exchange operational and policy information on their CCS programs.

Alberta's Alternative and Renewable Energy

Alberta is more than an oil and gas province. It is an energy province, which is demonstrated by its growth in alternative and renewable energy capacity. In 2013, 46 per cent of the province's electricity generating capacity came from alternative and renewable energy sources, including wind, hydroelectricity, biomass generation and gas cogeneration.

Alternative and Renewable Electricity for 2013

Technology	Installed Capacity (MW)	% of Total Installed Capacity
Natural Gas Cogeneration	4,034	28%
Wind	1,113	8%
Hydroelectric	900	6%
Biofuels	414	3%
Total	**6,461**	**46%**[1]

Note: [1] Totals do not add up due to rounding.

Micro-generation

In December 2013, the Micro-generation Regulation was renewed and extended until December 2015 to enable micro-generation to continue to develop in the province. The regulation enables customer choice in the source of their electricity and reduces the administrative and regulatory burden on micro-generators. The regulation establishes compensation for excess energy from micro-generation in a manner that is consistent with Alberta's competitive electricity market.

As of March 2014, over 900 micro-generation sites had been approved with a combined total capacity of approximately 4.8 megawatts. This represents an increase of almost 250 sites and 1.5 megawatts from March 2013.

In January 2009, the Government of Alberta's Micro-generation Regulation came into effect. This regulation provided a set of rules that allowed Albertans to generate their own electricity from alternative and renewable sources of energy and receive credit for any power they sent into the electricity grid. The majority of micro-generation installations are solar energy.

Bioenergy

Bioenergy production supports environmental and economic outcomes in the province. The Bioenergy Producer Credit Program (BPCP) encourages the development and production of a wide variety of bioenergy products including renewable fuels, electricity and heat with grant support based on actual production. Bioenergy production supports reductions of GHG emissions and landfill wastes and can result in additional value from products and economic growth.

Since its inception, Alberta's bioenergy programs have supported a tenfold increase in liquid biofuel production capacity, from 45 million litres in 2012 to over 400 million litres as of March 2014. The program also contributed to approximately 50 megawatts of additional electricity generating capacity. Over 90 per cent of bioenergy production under the current BPCP is produced from waste streams and approximately two megatons of GHG emissions is avoided annually from production. In addition, the BPCP has provided for technology innovation, enhanced research infrastructure, and demonstrations.

Renewable Fuel Standard

The province reduced GHG emissions from road transportation by more than one megaton under the Renewable Fuels Standard Regulation (RFS), which is the equivalent of removing 200,000 cars from Alberta roads. In 2012, over 550 million litres of renewable fuels were blended into gasoline and diesel fuel placed into the Alberta market. The blending requirement was exceeded in 2012 with the annual average blend of ethanol with gasoline at seven per cent, significantly exceeding the required blend of five per cent. The annual average blend of biodiesel and renewable diesel in diesel fuel was 2.1 per cent, which slightly exceeded the required blend of two per cent.

Alberta's RFS is a requirement to blend renewable fuels such as ethanol or biodiesel into fuels, like gasoline and diesel, which are sold to customers. The RFS requires an average of two per cent renewable diesel in diesel fuel and five per cent renewable ethanol in gasoline sold in Alberta. Renewable fuels used to meet the RFS must demonstrate at least 25 per cent fewer GHG emissions than the equivalent petroleum fuel.

Due to the lack of operating biofuel production capacity in the province in 2012, over 90 per cent of the blended biofuel was obtained from other provinces and countries. However, as of March 2013, biodiesel production capacity exceeded the volume required to meet RFS blending requirements for diesel fuel. Alberta's ethanol production capacity meets approximately 20 per cent of the RFS blending requirement for gasoline.

Developing Sustainable Energy Related Infrastructure

Alberta is recognized as an authority on successful management of flaring and venting. Alberta has made a financial commitment through the Global Gas Flaring Reduction Initiative (GGFR) to help other jurisdictions reduce the flaring of natural gas associated with oil production. The World Bank-sponsored GGFR is an international public-private partnership of governments, industry, and development organizations committed to poverty alleviation and environmental protection through gas utilization. The department participated in the GGFR's Steering Committee, Technical Network, and Regulatory Network meetings during 2013-14, receiving valuable insight into world-wide flaring and venting activity. This collaboration assists in defining the level of uncertainty of emissions' estimates reported by, or assumed of other jurisdictions.

Supporting Innovative Technology and Processing Improvements

The department continues to establish Alberta as a world-class centre for responsible energy development through support for the Innovative Energy Technologies Program (IETP). The program has approved 42 projects, 40 of which proceeded through the first six IETP rounds. In 2013-14, there were 11 active projects, five of which were completed during the year. These projects explore innovative ways to improve extraction efficiency, advance production technologies, and expand enhanced oil and gas recovery technologies to less accessible deposits. It is anticipated that increases in production efficiency will result in lower GHG emission profiles.

To encourage collaboration, private-sector investment, and information-sharing regarding innovation and new technologies, the department provides funding to research organizations and academic institutions for energy research and policy-related work. Specifically, the department once again provided grant funding to the Canadian Energy Research Institution, the Petroleum Technology Alliance of Canada, joint industry projects coordinated by Alberta Innovates Technology Futures, and the University of Calgary's energy policy work.

The IETP is a major component of the Energy Innovation Strategy, which looks to meet the future energy needs of Alberta by investing in research, technology and innovation. The IETP is a $200 million commitment by the Alberta government 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.

Transmission Connection and Cost Management

In January 2013, the Minister of Energy announced the following transmission cost management initiatives to be further evaluated and potentially implemented in 2013-14:

- AUC Cost Oversight - AUC was given broader powers to scrutinize the prudence of new transmission project expenditures;
- Cost Oversight Management - Transmission cost management policy development, including an approved cost estimate, cost oversight management, improved cost reporting and an expanded competitive procurement process for transmission development;
- AUC Transmission Cost Recovery Review;
- Transmission Connection Process Review; and
- Continuation of Transmission Facilities Cost Monitoring Committee (TFCMC).

Amendments to the Transmission Regulation in July 2013 repealed a subsection requiring the AUC to presume transmission expenditures were prudent, unless an intervener proved otherwise. As a result, the AUC has the authority to better scrutinize project expenditures without having to rely on interveners to make the case. It will be up to the transmission companies to prove that the expenditures of new transmission projects are prudent.

The department engaged in several working group sessions to develop holistic transmission cost management policies. Multi-stakeholder transmission cost management policy development working group sessions were held throughout the fall of 2013 to discuss the benefits, alternatives, risks, and implications of various policy options. Approved policy options will be implemented with Transmission Regulation amendments in 2014.

The Alberta Electric System Operator (AESO) developed a competitive process to introduce competition and promote cost effective transmission development. The first AESO competitive procurement process for a transmission facility project is currently underway.

The AUC initiated an examination of alternative approaches and rate treatments that could mitigate or smooth the impact on consumers of rate or bill increases resulting from significant anticipated investments in the electric transmission sector. Stakeholder engagements and procedural submissions have been initiated and will conclude in the summer of 2014.

The TFCMC provides earlier access to information on the costs, scope, schedule, and variances of large transmission facility projects estimated to cost in excess of $100 million. The TFCMC released two reports in 2013 focusing on cost impacts, cost-recovery mechanisms, and project summaries of all transmission projects being monitored on a monthly basis.

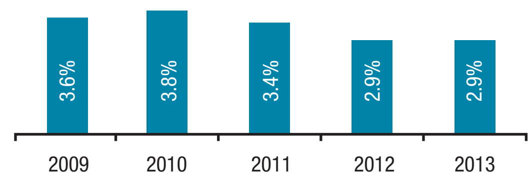
Performance Measure 3.a: Transmission losses

Target

To maintain a minimum level in transmission losses. The target for 2013-14 was 3.0 per cent or less.

Figure 3.a

Transmission losses (per cent).



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 is delivered where and when it is needed. By ensuring development of a hardy 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 the 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.

Performance Measure 3.b: Power generation

Target

Maintain a minimum seven per cent margin over peak demand.

Discussion of Results

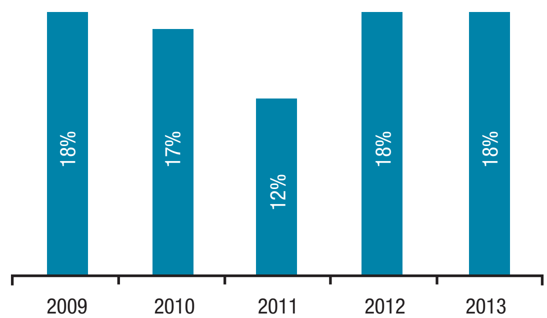
Alberta's economic prosperity and high standard of living relies on access to reliable and plentiful electricity. The Government of Alberta has created a framework that facilitates a competitive wholesale power market. This framework has resulted, over the long term, in electricity supply keeping pace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

For this measure, the seven per cent margin is a specific identifiable reliability requirement set by the Western Electricity Coordinating Council (WECC), the regional entity responsible for coordinating electric system reliability in the Western Interconnection that extends from Canada to Mexico.

Firm electricity generating capacity was calculated at 13,181 megawatts (MW) for 2013. This was a 700 MW (or 5.6 per cent) increase over the 2012 level. The peak demand in the winter period of the climatic year (October 1, 2013 to March 31, 2014) reached the all-time high of 11,139 MW. This demand was 540 MW (or 5.1 per cent) higher than the peak of 10,599 MW set in the winter climatic year October 1, 2011 to March 31, 2012. In 2013, the margin between the firm electricity generating capacity and peak demand was 18 per cent, indicating no change from the 2012 margin level.

Figure 3.b

Margin (megawatts) between firm generating capacity[1] 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.

Performance Measure 3.c: Timeliness of the needs and facility applications

Target

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

Discussion of Results

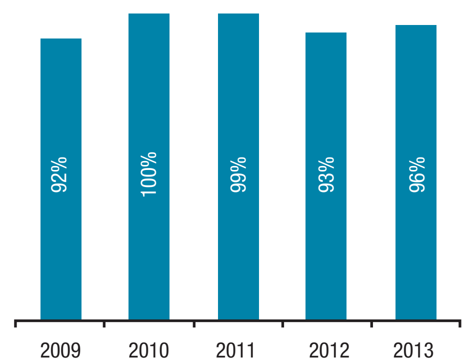
In accordance with standards established in Alberta law, the AUC when considering an application for an approval, permit or licence in respect of a needs identification document, transmission line or part of a transmission line, must make a decision in a timely manner, and if possible, within 180 days after receipt of a complete application.

For 2013, the AUC met this standard 96 per cent of the time as 77 of 80 decisions were issued within the 180-day timeline.

The three decisions that missed the 180-day timeline were related to infrastructure proceedings which encountered hearing delays, adjournment requests and, in some cases, additional process steps.

Figure 3.c

Percentage of needs and facility applications determined within 180 days of the application being deemed complete.



Source: Alberta Utilities Commission.

Notes: The 2009 actual was revised from 98 per cent to 92 per cent to capture only needs and facility applications. The previously recorded results included applications for power plants and other minor facility applications, which do not have the 180 day legislative deadline.

Hearing adjournment requests typically arise when interveners or their representatives are unable to attend a scheduled hearing. As a result, rescheduling and securing venues for new hearings results in delays to the overall timelines.

Appendix A: Performance Measure Methodologies

Performance Measure 1.a: Combined tax and royalty rates for Alberta natural gas and conventional oil production, compared to similar jurisdictions

Methodology

Combined tax and royalty rate includes the following:

- Royalties;
- Corporate income taxes (federal & state/provincial);
- Severance taxes; and
- Ad valorem taxes

Comparator jurisdictions for Alberta include British Columbia, Saskatchewan, and the following U.S. states: California, Colorado, Louisiana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas, Utah, and Wyoming. The department regularly monitors resource development activity throughout North America and updates the list of comparator jurisdictions as required to reflect the top competing jurisdictions against Alberta.

This measure was chosen as a proxy for total government share. The combined tax and royalty rate is a) measurable, b) commonly understood, c) pro-active and timely, d) comparable with other jurisdictions; and, e) consistent with other measures of competitiveness.

This measure should be treated as an early warning signal to indicate whether the royalty system requires amendment. If comparison of combined tax and royalty rate is indicating possible fiscal system change, closer attention to the other indicators such as government share, investor rate of return, and net present value would be required. This is more appropriately addressed through special studies (such as the Investment Competitiveness Study) that are future-focused and account for the many factors that influence investment decisions.

The combined tax and royalty rates from all 13 comparator jurisdictions are manually calculated from data obtained from reliable third-party external sources, except for the Alberta effective royalty rate which is provided from within the ministry. The calculation of Alberta's effective natural gas royalty rates was modified to better represent the combined effective royalty rates for natural gas and natural gas liquids (NGLs) net of any royalty adjustments and eligible cost deductions. The combined tax and royalty values for each jurisdiction represent a summation of the various fiscal terms with some adjustments made to account for the deductibility of a fiscal term in the calculation of another.

The combined tax and royalty rates for each jurisdiction are then ranked with the lowest three comprising the first quartile.

For the years 2009-2011, the combined tax and royalty rates for Alberta natural gas were updated retroactively this year to reflect the revision in calculating Alberta's effective natural gas royalty rates. As such, these revisions (r) are identified in the Performance Measures Summary Table. Even with the methodology revision, Alberta still remained within the first quartile of investment opportunities compared to similar jurisdictions.

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

Methodology

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. 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 and any discrepancies are followed up and resolved. The department collects the revenue for the Crown's volumes marketed either directly, or by the Crown's agents, calculates the net value of all royalty sales, and then remits the proceeds to Treasury.

Oil Sands Royalty:
Oil Sands Administrative and Strategic Information System (OASIS) calculates the monthly amounts to be collected, based on the Good Faith Estimates, the Monthly Royalty Calculations and the Non-Project Royalty reports and annual adjustments based on the End of Period Statements. All royalty reporting must be submitted electronically, to the department, using the web-based Electronic Transfer System. OASIS then sends the charge information to the Corporate Accounting Revenue System (CARS2). There are limited manual interfaces. An information report is available from OASIS to demonstrate 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 process is an auction in which companies or individuals submit bids on a parcel of oil sands rights. The highest bidder for each parcel is awarded an oil sands agreement.

Any company or individual who wants to acquire an oil sands or petroleum and natural gas agreement may submit a posting request electronically to the department, using the web-based Electronic Transfer System (ETS). The requested rights are examined to ensure availability for disposition. The requested lands are referred to the multi-agency Crown Mineral Disposition Review Committee to review for any surface access restrictions. The Committee provides the department with full information on the nature of any restriction (for example, seasonal access restrictions for the protection of wildlife habitats). A description of the restriction and contact information, in the form of an addendum, is attached to the parcel of rights when posted in the Public Offering Notice. The Public Offering Notice is published eight weeks in advance of the sale date and is available on the department's website. After the sale is completed, the surface restriction on a parcel is recorded in the Notice to Lessee as an attachment to the agreement document upon issuance.

Bids for sale parcels are created and submitted electronically through ETS until noon on sale day after which the sale is closed and ETS will not allow a user to submit or withdraw a bid after that time. Sale days always occur on a Wednesday. The total bid request for each parcel must include a $625 agreement issuance fee, the first year annual rental of $3.50 per hectare, and a bonus amount. There is a standard minimum bonus bid of $2.50 per hectare for petroleum and natural gas and oil sands leases and $1.25 per hectare for petroleum and natural gas licences and oil sands permits. The form of payment accepted for winning bids is by electronic funds transfer. The bidder must have an ETS account before creating and submitting a bid.

The sale results are published on the department'swebsite, by 3:30 pm on the same day that the sale is conducted. The results include the parcel number, the name of each successful bidder and the bonus amount paid for each parcel.

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 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.c: Alberta's oil sands supply share of global oil consumption

Methodology

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

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

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

Performance Measure 2.a: Albertans' assessment of their energy knowledge

Methodology

The intent of this performance measure is to survey Albertans about their knowledge of energy using their knowledge of the energy industry as a proxy. To ensure validity, the same question has been asked every two years since the 2009 benchmark was established.

Performance Measure 2.b: Regulatory noncompliance

Methodology

The AER established a three per cent target for this measure based on historical data. The target is the expected percentage of field inspections finding high-risk regulatory noncompliance.

The AER uses a risk-based inspection strategy that focuses on higher-value inspection work. The AER selects a sample for inspections based on both internally defined risk criteria and external factors, such as incidents or complaints.

AER Field Operations staff inspect operations of the upstream oil and gas industry with respect to the drilling, production, and disposition of hydrocarbons and associated wastes. All inspection results are recorded as satisfactory, low risk noncompliant or high risk noncompliant and are entered into the Field Surveillance Inspection System database, with the exception of inspections of waste plants. These are tracked manually because the waste plants do not have licence numbers. Inspections and investigations are counted for the year that the event was initiated. Field inspections for this measure are initial inspections for drilling, gas facility, oil facility, pipeline, well service, drilling waste, well sites, and waste management operations completed in the calendar year.

Incidents or complaints change the focus of the inspection strategy from year to year as the AER expands the inspections to see if the problem is occurring at other sites. The findings of these inspections can have significant impact on the reported result.

Performance Measure 3.a: Transmission losses

Methodology

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:

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

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:

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

Performance Measure 3.b: Power generation

Methodology

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 recorded system demand (in megawatt-hours) in the climatic year (October 1, 2013 through to March 31, 2014) as recorded by the Alberta Electric System Operator.

Performance Measure 3.c: Timeliness of the needs and facility applications

Methodology

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

MINISTRY OF ENERGY

FINANCIAL STATEMENTS
For the year ended March 31, 2014

Independent Auditor's Report

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AUDITOR GENERAL *Alberta*

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, 2014, and the consolidated statements of operations 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, 2014, and the results of its operations and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Original signed by Merwan N. Saher, FCA
Auditor General

June 4, 2014
Edmonton, Alberta

MINISTRY OF ENERGY

CONSOLIDATED STATEMENT OF OPERATIONS

Year ended March 31, 2014

	(in thousands)		
	2014		**2013**
	Budget	**Actual**	**Actual Restated (Note 19)**
Revenues (Schedule 1)			
Non-Renewable Resource Revenue	$ 7,250,000	$ 9,578,070	$ 7,779,175
Freehold Mineral Rights Tax	152,000	145,928	119,047
Industry Levies and Licences	203,112	214,968	159,302
Other Revenue	12,759	33,171	31,799
Net Income from Government Business Enterprises	144	1,343	-
	7,618,015	9,973,480	8,089,323
Expenses - Directly Incurred (Note 2 and Schedules 2 and 3)			
Ministry Support Services	6,801	7,015	6,762
Resource Development and Management	87,720	105,204	112,990
Bioenergy Initiatives	98,000	68,202	44,329
Costs of Marketing Oil	43,100	173,622	156,788
Energy Regulation	170,857	208,310	173,726
Utilities Regulation	37,764	31,571	36,143
Carbon Capture and Storage	182,100	116,056	116,011
Orphan Well Abandonment	12,750	16,172	13,001
Oil Sands Sustainable Development Secretariat	3,089	1,527	1,736
Settlements Related to the Land-Use Framework	-	72,267	30,500
	642,181	799,946	691,986
Net Operating Results	$ 6,975,834	$ 9,173,534	$ 7,397,337

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

MINISTRY OF ENERGY

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

As at March 31, 2014

	(in thousands) 2014	2013
Assets		
Cash and Cash Equivalents (Note 3)	$ 690,597	$ 343,554
Accounts Receivable (Note 4)	1,338,555	981,794
Inventory (Note 16)	2,987	13,430
Prepaid Expenses	10,853	11,269
Equity in Government Business Enterprise (Schedule 4)	716	-
Tangible Capital Assets (Note 5)	97,099	94,406
	$ 2,140,807	$ 1,444,453
Liabilities		
Accounts Payable and Accrued Liabilities	$ 228,380	$ 321,760
Gas Royalty Deposits (Note 6)	260,017	337,467
Unearned Revenue	79,327	79,127
Security Deposits (Note 7)	100,211	52,520
Tenant Incentives	23,618	24,284
Pension Obligations (Note 8)	4,056	4,025
	695,609	819,183
Net Assets (Liabilities):		
Net Assets (Liabilities) at Beginning of Year	625,270	322,027
Adjustment to Opening Net Assets (Schedule 4)	(627)	-
Net Operating Results	9,173,534	7,397,337
Net Financing Provided from (for) General Revenues	(8,352,979)	(7,094,094)
Net Assets (Liabilities) at End of Year	1,445,198	625,270
	$ 2,140,807	$ 1,444,453

Contractual Obligations, Commitments and Contingent Liabilities (Notes 10, 11 and 12)

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

MINISTRY OF ENERGY

CONSOLIDATED STATEMENT OF CASH FLOWS

Year ended March 31, 2014

	(in thousands)	
	2014	**2013**
Operating Transactions		
Net Operating Results	$ 9,173,534	$ 7,397,337
Non-cash items included in Net Operating Results		
Amortization	20,561	21,046
Loss on Disposal of Tangible Capital Assets	264	971
	9,194,359	7,419,354
(Increase) Decrease in Accounts Receivable	(356,761)	55,105
Decrease in Inventory	10,443	14,554
Decrease (Increase) in Prepaid Expenses	416	(2,173)
(Increase) in Equity in Government Business Enterprise	(1,343)	-
(Decrease) in Accounts Payable and Accrued Liabilities	(93,380)	(399,625)
Increase in Unearned Revenue	200	490
(Decrease) in Tenant Incentives	(666)	(1,410)
Increase in Pension Obligation	31	14
Cash Provided by Operating Transactions	8,753,299	7,086,309
Capital Transactions		
Acquisition of Tangible Capital Assets	(23,518)	(14,617)
Cash Applied to Capital Transactions	(23,518)	(14,617)
Financing Transactions		
Net Financing Provided (for) General Revenues	(8,352,979)	(7,094,094)
(Decrease) in Gas Royalty Deposits	(77,450)	(68,725)
Increase in Security Deposits	47,691	6,096
Cash Applied to Financing Transactions	(8,382,738)	(7,156,723)
Decrease in cash and cash equivalents	347,043	(85,031)
Cash and cash equivalents at Beginning of Year	343,554	428,585
Cash and cash equivalents at End of Year	$ 690,597	$ 343,554

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

MINISTRY OF ENERGY
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
MARCH 31, 2014
(in thousands)

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.

Basis of Financial Reporting

Basis of Consolidation

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

Based on the change in mandate of the Commission and the increase in for-profit making activities, as of January 1, 2013 the Commission concluded that it met the definition of a government business enterprise as defined by public sector accounting standards and was required to adopt International Financial Reporting Standards (IFRS).

The government business enterprise of the Commission, which reports under IFRS, is consolidated on a modified equity basis.

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.

Revenues

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

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

Basis of Financial Reporting (cont'd)

Basis of Consolidation (cont'd)

Revenues (cont'd)

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 and royalty 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.

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.

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.
- current service costs for the defined benefit pension plans. 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.

<u>Incurred by Others</u>

Services contributed by other entities in support of the Ministry operations are not recognized and are disclosed in Schedule 3 and are not reflected in the consolidated statements of operations.

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

Basis of Financial Reporting (cont'd)

Basis of Consolidation (cont'd)

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.

Assets acquired by right are not included.

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 and the threshold for major systems enhancements is $100. The threshold for all other tangible capital assets is $5.

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

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

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.

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, advances, accounts payable and accrued liabilities, security deposits, and gas royalty deposits are estimated to approximate their carrying values because of the short-term nature of these instruments.

Net Assets/Net Liabilities

Net assets/net liabilities represent the difference between the carrying value of assets held by the Ministry and its liabilities.

Canadian Public Sector Accounting Standards require a "net debt" presentation for the statement of financial position in the summary financial statements of governments. Net debt presentation reports the difference between financial assets and liabilities as "net debt" or "net financial assets" as an indicator of the future revenues required to pay for past transactions and events. The Ministry operates within the government reporting entity, and does not finance all its expenditures by independently raising revenues. Accordingly, these financial statements do not report a net asset/debt indicator.

MINISTRY OF ENERGY
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
MARCH 31, 2014
(in thousands)

NOTE 3 CASH AND CASH EQUIVALENTS

Cash consists of deposits in the Consolidated Cash Investment Trust Fund which is 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. As at March 31, 2014, securities held by the Fund have a time-weighted rate of return of 1.2% per annum (2013 - 1.3% per annum). Deposits received by the Ministry as security against leases are included in cash.

NOTE 4 ACCOUNTS RECEIVABLE

Accounts receivable royalties are secured by a claim against the mineral leases.

NOTE 5 TANGIBLE CAPITAL ASSETS

	Land	Equipment(1)	Computer hardware and software	Total
Estimated Useful Life	Indefinite	3 to 10 years	3 to 10 years	
Historical Cost(2)				
Beginning of Year	$ 282	$ 65,958	$ 208,450	$ 274,690
Additions	-	8,309	15,209	23,518
Disposals, Including Write-Downs	-	(10)	(518)	(528)
	$ 282	$ 74,257	$ 223,141	$ 297,680
Accumulated Amortization				
Beginning of Year	$ -	$ 29,845	$ 150,439	$ 180,284
Amortization Expense	-	5,712	14,849	20,561
Effect of Disposals	-	(9)	(255)	(264)
	$ -	$ 35,548	$ 165,033	$ 200,581
Net Book Value, March 31, 2014	$ 282	$ 38,709	$ 58,108	$ 97,099
Net Book Value, March 31, 2013	$ 282	$ 36,113	$ 58,011	$ 94,406

(1) Equipment includes leasehold improvements, office equipment and furniture, and other equipment.

(2) Historical cost includes work-in-progress at March 31, 2014 totaling $3,893 (2013 - $1,567) comprised of computer hardware and software.

NOTE 6 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.

(in thousands)

NOTE 7 SECURITY DEPOSITS

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, 2014, the Ministry held $100,211 (2013 - $52,520) in cash and an additional $1,595,700 (2013 - $112,580) in letters of credit of which, $29,343 in cash and $1,392,151 in letters of credit related to deposits received due to additional responsibilities assumed from ESRD. The security, along with any interest earned, will be returned to the depositor upon meeting specified refund criteria.

NOTE 8 EMPLOYEE FUTURE BENEFITS

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 $24,771 for the year ended March 31, 2014 (2013 - $20,931). Departments are not responsible for future funding of the plan deficit other than through contribution increases.

At December 31, 2013, the Management Employees Pension Plan reported a surplus of $50,457 (2012 - deficiency $303,423), the Public Service Pension Plan reported a deficiency of $1,254,678 (2012 deficiency - $1,645,141) and the Supplementary Retirement Plan for Public Service Managers reported a deficiency of $12,384 (2012 - deficiency $51,870).

The Ministry also participates in two multi-employer Long Term Disability Income Continuance Plans. At March 31, 2014, the Bargaining Unit Plan reported an actuarial surplus of $75,200 (2013 - surplus $51,717) and the Management, Opted Out and Excluded Plan an actuarial surplus of $24,055 (2013 - surplus $18,327). 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 date used to measure all pension plan assets and accrued benefit obligations was March 31, 2014. The effective date of the most recent actuarial funding valuation for SEPP was December 31, 2011. The effective date of the next required funding valuation for SEPP is December 31, 2014.

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

a) AER

	2014	2013
Accrued benefits obligations		
Discount rate	5.3%	5.0%
Rate of compensation increase	3.8%	3.8%
Long – term inflation rate	2.3%	2.3%

Pension benefit costs for the year	2014	2013
Discount rate	5.0%	5.0%
Expected rate of return on plan assets	5.0%	5.0%
Rate of compensation increase	3.8%	3.8%

(in thousands)

NOTE 8 EMPLOYEE FUTURE BENEFITS (cont'd)

a) AER (cont'd)

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

	2014	2013
Market value of plan assets	$ 37,859	$ 34.568
Accrued benefit obligation	43,231	39,732
Plan (deficit)	(5,372)	(5,164)
Unamortized actuarial loss	2,081	1,904
Pension obligations	$ (3,291)	$ (3,260)

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

	2014	2013
Equity securities	49.4%	50.9%
Debt securities	39.0%	38.0%
Other	11.6%	11.1%
	100.0%	100%

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

	2014	2013
AER contribution	$ 2,630	$ 2,468
Employees' contribution	507	444
Benefit paid	3,024	1,859

b) AUC

	2014	2013
Accrued benefits obligations		
Discount rate	5.00%	4.82%
Rate of compensation increase	3.75%	3.75%
Long-term inflation rate	2.25%	2.25%
Pension benefit costs for the year		
Discount rate	4.82%	4.82%
Expected rate of return on plan assets	4.82%	4.82%
Rate of compensation increase	3.75%	3.75%

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

	2014	2013
Market value of plan assets	$ 6,802	$ 5,917
Accrued benefit obligation	8,141	7,175
Plan deficit	(1,339)	(1,258)
Unamortized actuarial loss	574	493
Accrued pension liability	$ (765)	$ (765)

(in thousands)

NOTE 8 EMPLOYEE FUTURE BENEFITS (cont'd)

b) AUC (cont'd)

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

	2014	2013
AUC contribution	$ 717	$ 715
Employees' contribution	108	111
Benefit paid	458	126

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

	2014	2013
Equity securities	52.41%	51.90%
Debt securities	29.44%	30.40%
Other	18.15%	17.70%
	100.00%	100.00%

NOTE 9 TRUST FUNDS UNDER ADMINISTRATION

The Ministry administers trust funds which are regulated funds consisting of public money over which the Legislature has no power of appropriation. Because the Province has no equity in the funds, and administers them for the purpose of various trusts, they are not included in the Ministry's financial statements.

As at March 31, trust funds under administration were as follows:

	2014	2013
Oil and Gas Conservation Trust	$ 4,364	$ 4,201

NOTE 10 CONTRACTUAL OBLIGATIONS

Contractual obligations to outside organizations in respect of contracts entered into before March 31, 2014 amount to $1,420,723 (2013 - $1,609,641). These contractual obligations will become expenses of the Ministry when terms of the contracts are met.

These amounts include obligations under long-term leases with lease payment requirements in future years of:

	Grant Agreements	Service Contracts	Long-term Leases	Total
2015	$ 243,192	$ 18,835	$ 13,635	$ 275,662
2016	409,109	5,266	13,980	428,355
2017	54,340	4,600	14,034	72,974
2018	59,290	5	14,030	73,325
2019	49,600	5	11,912	61,517
Thereafter	377,320	5	131,565	508,890
	$ 1,192,851	**$ 28,716**	**$ 199,156**	**$ 1,420,723**

(in thousands)

NOTE 11 COMMITMENTS

Alberta Petroleum Marketing Commission

(a) North West Redwater Partnership

On November 8th, 2012 the North West Redwater Partnership (the "Partnership"), 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 the Partnership 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. The Partnership 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 operating, debt, equity, and incentive fee components on 37,500 barrels per day of bitumen (75% of the project's feedstock) for 30 years. The toll includes both flow through costs as well as costs of facility construction, estimated to be $5.7 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 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 toll under the processing agreement, assuming a $5.7 billion Facility Capital Cost, market interest rates and 2% operating cost inflation rate, is estimated to be:

2014	$	0
2015	$	0
2016	$	248,000
2017	$	532,000
2018	$	543,000
Beyond 2018	$	17,773,000

Please see Note 18 Subsequent Events.

(b) Energy East Pipeline Project

The Commission has signed a Transportation Service Agreement (TSA) with Energy East Pipeline Limited Partnership to purchase 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. Under the take-or-pay obligation, the Commission has a minimum obligation to pay $3.4 billion 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 2018.

2014	$	0
2015	$	0
2016	$	0
2017	$	0
2018	$	170,000
Beyond 2018	$	3,230,000

NOTE 12 CONTINGENT AND OTHER LIABILITIES

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

Set out below are details of contingencies resulting from administrative actions and litigation, other than those reported as liabilities.

(a) Land Claims

The government identifies and sets aside specific tracts of land to satisfy land claims made by Indian Bands. The claims related to these lands are under negotiation but are not yet resolved. When these land claims will be resolved is unknown. In the opinion of management, any losses that may result from the eventual settlement of these land claims cannot be determined at this time.

(b) Legal Claims

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

The Ministry has been named in one (2013 Restated - three) claim of which the outcome is not determinable. This claim (2013 Restated - two) has a specified amount totaling $15,000 (2013 Restated - $300,030). There were zero (2013 Restated – one) claims with no amounts specified. The resolution of indeterminable claim may result in a liability, if any, that may be significantly lower than the claimed amount.

NOTE 13 MEASUREMENT UNCERTAINTY

Measurement uncertainty exists when there is a variance between the recognized or disclosed amount in the consolidated financial statements and another reasonably possible amount. Natural gas and by-products revenue recorded as $1,102,999 and bitumen royalty recorded as $5,222,178 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. These costs and volumes could vary significantly from that 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, natural gas and by-products revenue could change by $175,000.

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.

NOTE 14 RELATED PARTY TRANSACTIONS

The Ministry paid $4,351 (2013 - $5,438) to various other Government of Alberta departments, agencies or funds for grants, supplies and/or services during the fiscal year and received $148 (2013 - $148) as revenue.

Accommodations, legal, telecommunications, personnel, internal audit 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 3.

NOTE 15 ROYALTY REDUCTION PROGRAMS

The Ministry provides twelve 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, 2014, the royalties received under these programs were reduced by $1,191,501 (2013 - $682,403).

NOTE 16 INVENTORY

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

NOTE 17 BITUMEN CONSERVATION

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 $43,266 (2013 - $35,079).

NOTE 18 SUBSEQUENT EVENTS

North West Redwater Partnership

A revised Processing Agreement was executed on April 7, 2014 (available on the Department of Energy website). The tolls are now estimated to be $26 billion over 30 years, beginning the earlier of the commencement of commercial operations (estimated to be September 1, 2017) or June 1, 2018. The tolls under the revised processing agreement, assume an $8.5 billion Facility Capital Cost, market interest rates and 2% operating cost inflation rate.

On April 7, 2014, the Commission executed debt financing agreements with the Partnership to lend up to $324 million, as well as additional loans if required. These loans will earn interest at a rate of prime plus 6 percent, and will be repaid over 10 years starting the year after project start-up. Additional loans may be granted under the agreements which do not have a fixed commitment amount or maturity date, at the interest rate of prime plus 6 percent. The debt provided under the agreements would be subordinated to the Partnerships debt financing raised from external creditors.

On April 9, 2014, the Commission advanced $112.5 million to the Partnership. On that same day the Commission borrowed $112.5 million from Treasury Board and Finance at an effective interest rate of 1.0253%.

As part of the restructuring, 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, start-up and operation of the Sturgeon Refinery until the subordinated debt is fully repaid.

NOTE 19 COMPARATIVE FIGURES

Certain 2013 figures have been reclassified to conform to the 2014 presentation.

Costs of marketing oil were previously netted against crude oil royalties. As a result of a change in accounting practices, crude oil royalties have been grossed up by the costs of marketing oil in the amount of $173,622 (2013 - $156,788).

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 SCHEDULES TO FINANCIAL STATEMENTS

Revenues

Year ended March 31, 2014

	2014		2013
	Budget	Actual	Actual Restated
		(in thousands)	
Non-Renewable Resource Revenue			
Bitumen Royalty	$ 3,367,000	$ 5,222,178	$ 3,559,924
Crude Oil Royalty	1,615,000	2,475,992	2,037,819
Natural Gas and By-Products Royalty	965,000	1,102,999	954,492
Bonuses and Sales of Crown Leases	1,148,000	588,108	1,053,401
Rentals and Fees	145,000	172,719	176,263
Coal Royalty *	10,000	16,074	(2,724)
	7,250,000	9,578,070	7,779,175
Freehold Mineral Rights Tax	152,000	145,928	119,047
Industry Levies and Licenses	203,112	214,968	159,302
Net Income from Government Business Enterprise (Schedule 4)	144	1,343	-
Other Revenue			
Other	9,859	31,910	30,662
Interest	2,900	1,261	1,137
	12,759	33,171	31,799
Total Revenue	$ 7,618,015	$ 9,973,480	$ 8,089,323

* The negative revenue for Coal Royalty revenue in 2012-13 was primarily due to a large refund of $16 million for production in prior year.

MINISTRY OF ENERGY **Schedule 2**

CONSOLIDATED SCHEDULES TO FINANCIAL STATEMENTS

Expenses - Directly Incurred Detailed by Object

Year ended March 31, 2014

	2014		2013
	Budget	Actual	Actual Restated
		(in thousands)	
Salaries, Wages and Employee Benefits	$ 211,050	$ 238,960	$ 215,731
Supplies and Services	115,870	266,401	241,115
Grants	280,100	183,846	170,310
Amortization of Tangible Capital Assets	23,088	20,561	21,046
Orphan Well Abandonment	12,750	16,172	13,001
Financial Transactions and Other	120	74,750	31,538
Total Expenses before Recoveries	642,978	800,690	692,741
Less Recovery from Support Service Arrangements with Related Parties (a)	(797)	(744)	(755)
Total Expenses	$ 642,181	$ 799,946	$ 691,986

(a) The Ministry provides financial services to the Ministry of Tourism, Parks and Recreation and the Ministry of Environment and Sustainable Resource Development. Costs incurred by the Ministry for these services are recovered from the Ministry of Environment and Sustainable Resource Development.

MINISTRY OF ENERGY **Schedule 3**

CONSOLIDATED SCHEDULES TO FINANCIAL STATEMENTS

Allocated Costs

Year ended March 31, 2014

(in thousands)

	2014								2013
		Expenses Incurred by Others							Total
Program	Expenses (1)	Accommodation Costs (2)	Transportation Costs	Service Alberta	GOA Learning Centre	Legal Services	Internal Audit Services	Total Expenses	Expenses Restated
Ministry Support Services	$ 7,015	$ 470	$ -	$ -	$ -	$ 379	$ -	$ 7,864	$ 7,302
Resource Development and Management	105,204	5,868	90	3,636	36	4,045	115	118,994	128,992
Bioenergy Initiatives	68,202	67	-	-	-	-	-	68,269	44,373
Costs of Marketing Oil	173,622	-	-	-	-			173,622	156,788
Energy and Utilities Regulation	208,310	-	-	-	-	-	-	208,310	173,813
Utilities Regulation	31,571	-	-	-	-	-	-	31,571	36,143
Carbon Capture and Storage	116,056	59	-	-	-	-	-	116,115	116,011
Orphan Well Abandonment	16,172	-	-	-	-	-	-	16,172	13,098
Oil Sands Sustainable Development Secretariat	1,527	84	-	-	-	-	-	1,611	1,736
Settlements Related to the Land-Use Framework	72,267	-	-	-	-	-	-	72,267	30,500
	$ 799,946	$ 6,548	$ 90	$ 3,636	$ 36	$ 4,424	$ 115	$ 814,795	$ 708,756

(1) Expenses - Directly Incurred as per Statement of Operations, excluding valuation adjustments.

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

MINISTRY OF ENERGY **Schedule 4**

CONSOLIDATED SCHEDULES TO FINANCIAL STATEMENTS

Equity in Government Business Enterprise

Year ended March 31, 2014

(in thousands)

		2014
Accumulated surpluses		
Opening accumulated surplus - Alberta Petroleum Marketing Commission [a]		(627)
Total revenue		6,315
Total expense		4,972
Net income		1,343
Accumulated surpluses at end of year		716
Represented by		
Assets		
Cash and short-term investments	$	16,166
Other assets		225,084
Total assets		241,250
Liabilities		
Accounts payable		24,212
Due to the Department of Energy		216,322
Total liabilities		240,534
		716
Accumulated surpluses at end of year		
Alberta Petroleum Marketing Commission		716
Equity in commercial enterprises at end of year		716

[a] As of January 1, 2013, the Alberta Petroleum Marketing Commission transitioned to a Government Business Enterprise. To reflect this change, an adjustment has been made to the opening net assets of the Ministry of Energy in the amount of ($627).

DEPARTMENT OF ENERGY

FINANCIAL STATEMENTS
For the year ended March 31, 2014

Independent Auditor’s Report

Statement of Operations

Statement of Financial Position

Statement of Cash Flows

Notes to the Financial Statements

Schedules to Financial Statements

AUDITOR GENERAL
Alberta

Independent Auditor's Report

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, 2014, and the statements of operations 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, 2014, and the results of its operations and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Original signed by Merwan N. Saher, FCA
Auditor General

June 4, 2014
Edmonton, Alberta

DEPARTMENT OF ENERGY

STATEMENT OF OPERATIONS

Year ended March 31, 2014

	2014		2013
	Budget (Schedule 3)	Actual	Actual Restated (Note 15)
		(in thousands)	
Revenues (Schedule 1)			
Non-Renewable Resource Revenue	$ 7,250,000	$ 9,578,070	$ 7,779,175
Freehold Mineral Rights Tax	152,000	145,928	119,047
Other Revenue	500	24,415	23,620
	7,402,500	9,748,413	7,921,842
Expenses - Directly Incurred (Note 2(b) and Schedule 6)			
Program (Schedule 2)			
Ministry Support Services	6,801	7,015	6,762
Resource Development and Management	87,724	105,279	120,070
Bioenergy Initiatives	98,000	68,202	44,329
Costs of Marketing Oil	43,100	173,622	156,788
Oil Sands Sustainable Development Secretariat	3,085	1,527	1,736
Energy Regulation	-	36,300	47,543
Settlements Related to the Land-Use Framework	-	72,267	30,500
Carbon Capture and Storage	182,100	116,056	116,011
	420,810	580,268	523,739
Net Operating Results	$ 6,981,690	$ 9,168,145	$ 7,398,103

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

DEPARTMENT OF ENERGY

STATEMENT OF FINANCIAL POSITION

As at March 31, 2014

	2014	2013 Restated (Note 15)
	(in thousands)	
Assets		
Cash and Cash Equivalents (Note 3)	$ 536,100	$ 231,344
Accounts Receivable (Note 4)	1,338,999	963,216
Inventory (Note 14)	2,987	13,430
Tangible Capital Assets (Note 5)	34,483	35,452
	$ 1,912,569	$ 1,243,442
Liabilities		
Accounts Payable and Accrued Liabilities (Note 6)	$ 196,139	$ 263,441
Gas Royalty Deposits (Note 7)	260,016	337,467
Unearned Revenue	76,356	77,642
	$ 532,511	$ 678,550
Net Assets:		
Net Assets at Beginning of Year	564,892	260,883
Net Operating Results	9,168,145	7,398,103
Net Financing Provided for General Revenues	(8,352,979)	(7,094,094)
Net Assets at End of Year	1,380,058	564,892
	$ 1,912,569	$ 1,243,442

Contingent Liabilities and Contractual Obligations (Notes 8 and 9)

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

DEPARTMENT OF ENERGY

STATEMENT OF CASH FLOWS

Year ended March 31, 2014

		2014		2013 Restated
		(in thousands)		
Operating Transactions				
Net Operating Results	$	9,168,145	$	7,398,103
Non-cash Items included in Net Operating Results				
Amortization		7,274		7,692
		9,175,419		7,405,795
(Increase) Decrease in Accounts Receivable		(375,783)		51,063
Decrease in Inventory		10,443		14,555
(Decrease) in Accounts Payable and Accrued Liabilities		(67,302)		(390,780)
(Decrease) Increase in Unearned Revenue		(1,286)		528
Cash Provided by Operating Transactions		8,741,491		7,081,161
Capital Transactions				
Acquisition of Tangible Capital Assets		(6,305)		(5,785)
Cash Applied to Capital Transactions		(6,305)		(5,785)
Financing Transactions				
Net Financing Provided for General Revenues		(8,352,979)		(7,094,094)
Decrease in Gas Royalty Deposits		(77,451)		(68,725)
Cash Applied to Financing Transactions		(8,430,430)		(7,162,819)
Increase in Cash and Cash Equivalents		304,756		(87,443)
Cash and Cash Equivalents at Beginning of Year		231,344		318,787
Cash and Cash Equivalents at End of Year	$	536,100	$	231,344

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 unearned (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.

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 and royalty 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.

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

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

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.

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.

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 and the threshold for major systems enhancements is $100. The threshold for all other tangible capital assets is $5.

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.

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

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

Net Assets/Net Liabilities

Net assets/net liabilities represents the difference between the carrying value of assets held by the Department and its liabilities.

Canadian Public Sector Accounting Standards require a "net debt" presentation for the statement of financial position in the summary financial statements of governments. Net debt presentation reports the difference between financial assets and liabilities as "net debt" or "net financial assets" as an indicator of the future revenues required to pay for past transactions and events. The Department operates within the government reporting entity, and does not finance all its expenditures by independently raising revenues. Accordingly, these financial statements do not report a net debt indicator.

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, accounts payable and accrued liabilities, and gas royalty deposits are estimated to approximate their carrying values because of the short-term nature of these instruments.

Measurement Uncertainty

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 $1,102,999 and bitumen royalty recorded as $5,222,178 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. These costs and volumes could vary significantly from that 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, natural gas and by-products revenue could change by $175,000.

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.

(in thousands)

NOTE 3 CASH AND CASH EQUIVALENTS

Cash consists of deposits in the Consolidated Cash Investment Trust Fund which is 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. As at March 31, 2014, securities held by the Fund have a time-weighted rate of return of 1.2% per annum (2013 - 1.3% per annum).

NOTE 4 ACCOUNTS RECEIVABLE

Accounts receivable royalties are secured by a claim against the mineral leases.

	2014			2013
	Gross Amount	Allowance for Doubtful Accounts	Net Realizable Value	Net Realizable Value
Royalties	$1,118,128	-	$1,118,128	$796,546
Due from APMC	216,322	-	216,322	162,620
Bioenergy Grant Recoveries	2,905	$2,406	499	-
Other - AER	4,050	-	4,050	4,050
Total	$1,341,405	$2,406	$1,338,999	$963,216

NOTE 5 TANGIBLE CAPITAL ASSETS

	Equipment(1)	Computer Hardware and Software	Total
Estimated Useful Life	3 to 10 years	10 years	
Historical Cost(2)			
Beginning of Year	$ 23,172	$ 91,431	$ 114,603
Additions	3,616	2,689	6,305
Disposals, Including Write-downs	-	-	-
	$ 26,788	$ 94,120	$ 120,908
Accumulated Amortization			
Beginning of Year	15,526	63,625	79,151
Amortization Expense	2,977	4,297	7,274
Effect of Disposals	-	-	-
	18,503	67,922	86,425
Net Book Value at March 31, 2014	$ 8,285	$ 26,198	$ 34,483
Net Book Value at March 31, 2013	$ 7,646	$ 27,806	$ 35,452

(1) Equipment includes office equipment and furniture and other equipment.
(2) Historical cost includes work-in-progress at March 31, 2014 totaling $1,771 (2013 - $732) for computer software.

(in thousands)

NOTE 6 ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2014	2013
Trade	$ 133,147	$ 129,345
Overpayments of Royalties	62,992	133,596
Alberta Royalty Tax Credit	-	500
	$ 196,139	$ 263,441

NOTE 7 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 8 CONTINGENT LIABILITIES

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

Set out below are details of contingencies resulting from administrative actions and litigation, other than those reported as liabilities.

(a) Land Claims

The government identifies and sets aside specific tracts of land to satisfy land claims made by Indian Bands. The claims related to these lands are under negotiation but are not yet resolved. When these land claims will be resolved is unknown. In the opinion of management, any losses that may result from the eventual settlement of these land claims cannot be determined at this time.

(b) Legal Claims

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

The Department has been named in one (2013 Restated - three) claim of which the outcome is not determinable. This claim (2013 Restated - two) has a specified amount totaling $15,000 (2013 Restated - $300,030). There were zero (2013 Restated – one) claims with no amounts specified. The resolution of the indeterminable claim may result in a liability, if any, that may be significantly lower than the claimed amount.

(in thousands)

NOTE 9 CONTRACTUAL OBLIGATIONS

As at March 31, 2014, the Department had contractual obligations totaling $1,221,567 (2013 - $1,444,943).

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 in future years of:

	Grant Agreements	Service Contracts	Total
2015	$ 243,192	$ 18,835	$ 262,027
2016	409,109	5,266	414,375
2017	54,340	4,600	58,940
2018	59,290	5	59,295
2019	49,600	5	49,605
Thereafter	377,320	5	377,325
	$ 1,192,851	$ 28,716	$ 1,221,567

NOTE 10 TRUST FUNDS UNDER ADMINISTRATION

The Department administers the Oil and Gas Conservation Trust which is a regulated fund 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, 2014, the funds in the Oil and Gas Conservation Trust was $4,364 (2013 - $4,201).

NOTE 11 BENEFIT PLANS

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 $9,710 for the year ended March 31, 2014 (2013 - $8,939). Departments are not responsible for future funding of the plan deficit other than through contribution increases.

At December 31, 2013, the Management Employees Pension Plan reported a surplus of $50,457 (2012 - deficiency $303,423), the Public Service Pension Plan reported a deficiency of $1,254,678 (2012 deficiency - $1,645,141) and the Supplementary Retirement Plan for Public Service Managers reported a deficiency of $12,384 (2012 - deficiency $51,870).

The Department also participates in two multi-employer Long Term Disability Income Continuance Plans. At March 31, 2014, the Bargaining Unit Plan reported an actuarial surplus of $75,200 (2013 - surplus $51,717) and the Management, Opted Out and Excluded Plan an actuarial surplus of $24,055 (2013 - surplus $18,327). The expense for these two plans is limited to the employer's annual contributions for the year.

NOTE 12 ROYALTY REDUCTION PROGRAMS

The Department provides twelve 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, 2014, the royalties received under these programs were reduced by $1,191,501 (2013 - $682,403).

NOTE 13 BITUMEN CONSERVATION

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 $43,266 (2013 - $35,079).

NOTE 14 INVENTORY

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 15 COMPARATIVE FIGURES

Certain 2013 figures have been reclassified to conform to the 2014 presentation.

Costs of marketing oil were previously netted against crude oil royalties. As a result of a change in accounting practices, crude oil royalties have been grossed up by the costs of marketing oil in the amount of $173,622 (2013 - $156,788).

NOTE 16 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, 2014

	2014		2013
	Budget	**Actual**	**Actual Restated**
	(in thousands)		
Non-Renewable Resource Revenue (Note 12)			
Bitumen Royalty	$ 3,367,000	$ 5,222,178	$ 3,559,924
Crude Oil Royalty	1,615,000	2,475,992	2,037,819
Natural Gas and By-Products Royalty (Note 13)	965,000	1,102,999	954,492
Bonuses and Sales of Crown Leases	1,148,000	588,108	1,053,401
Rentals and Fees	145,000	172,719	176,263
Coal Royalty*	10,000	16,074	(2,724)
	7,250,000	9,578,070	7,779,175
Freehold Mineral Rights Tax	152,000	145,928	119,047
Other Revenue	500	24,415	23,620
Total Revenue	$ 7,402,500	$ 9,748,413	$ 7,921,842

* The negative revenue for Coal Royalty revenue in 2012-13 was primarily due to a large refund of $16 million for production in prior year.

DEPARTMENT OF ENERGY **Schedule 2**

SCHEDULE TO FINANCIAL STATEMENTS

EXPENSES - DIRECTLY INCURRED DETAILED BY OBJECT

Year ended March 31, 2014

	2014		2013
	Budget	Actual	Actual Restated
		(in thousands)	
Grants	$ 277,800	$ 220,146	$ 224,853
Salaries, Wages and Employee Benefits	79,772	81,144	77,859
Supplies and Services	57,327	197,698	183,522
Amortization of Tangible Capital Assets	6,588	7,274	7,692
Financial Transactions and Other	120	74,750	30,568
Total Expenses before Recoveries	421,607	581,012	524,494
Less Recovery from Support Service Arrangements with Related Parties [(a)]	(797)	(744)	(755)
	$ 420,810	$ 580,268	$ 523,739

(a) The Department provides financial services to the Department of Tourism, Parks and Recreation and the Department of Environment and Sustainable Resource Development. Costs incurred by the Department for these services are recovered from the Department of Environment and Sustainable Resource Development.

DEPARTMENT OF ENERGY **Schedule 3**

SCHEDULE TO FINANCIAL STATEMENTS

LAPSE/ENCUMBRANCE

Year ended March 31, 2014

	Voted Estimate [(1)]	Supplementary Estimate [(2)]	Adjustments [(3)]	Adjusted Voted Estimate	Voted Actuals [(4)]	Unexpended (Over Expended)
			(in thousands)			
Program - Operational						
Program - Ministry Support Services						
1.1 Minister's Office	$ 495	$ -	$ -	$ 495	$ 504	$ (9)
1.2 Associate Minister's Office	-	-	-	-	41	(41)
1.3 Deputy Minister's Office	495	-	-	495	542	(47)
1.4 Communications	1,269	-	-	1,269	930	339
1.5 Corporate Service	4,542	-	-	4,542	4,998	(456)
	6,801	-	-	6,801	7,015	(214)
Program - Resource Development and Management						
2.1 Revenue Collection	46,455	-	-	46,455	45,242	1,213
2.2 Resource Development	34,642	-	-	34,642	50,253	(15,611)
	81,097	-	-	81,097	95,495	(14,398)
Program - Bioenergy Initiatives						
3.1 Bioenergy Initiatives	98,000	-	-	98,000	68,202	29,798
	98,000	-	-	98,000	68,202	29,798
Program - Costs of Marketing Oil						
4.1 Costs of Marketing Oil	43,100	157,700	-	200,800	173,622	27,178
	43,100	157,700	-	200,800	173,622	27,178
Program - Oil Sands Secretariat						
5.1 Oil Sands Sustainable Development Secretariat	3,085	-	-	3,085	1,527	1,558
	3,085	-	-	3,085	1,527	1,558
Program - Energy Regulation						
6.1 Energy Regulation	-	34,300	-	34,300	36,300	(2,000)
	-	34,300	-	34,300	36,300	(2,000)
Settlements Related to the Land-use Framework[(5)]	-	-	72,267	72,267	72,267	-
	-	-	72,267	72,267	72,267	-
Total	$ 232,083	$ 192,000	$ 72,267	$ 496,350	$ 454,428	$ 41,922
Lapse/(Encumbrance)						$ 41,922
Program - Capital						
Program - Ministry Support Services	$ -	$ -	$ -	$ -	$ 88	$ (88)
Program - Resource Development and Management	6,315	-	(7)	6,308	6,217	91
Total	$ 6,315	$ -	$ (7)	$ 6,308	$ 6,305	$ 3
Lapse/(Encumbrance)						$ 3
Financial Transactions						
Settlements Related to the Land-use Framework	$ 30,500	$ -	$ -	30,500	28,389	$ 2,111
Total	$ 30,500	$ -	$ -	$ 30,500	$ 28,389	$ 2,111
Lapse/(Encumbrance)						$ 2,111

(1) As per "Operational Vote by Program", "Voted Capital Vote by Program" and "Financial Transation Vote by Program" page of 2013-14 Government Estimates.

(2) Per the Supplementary Supply Estimates approved on March 13, 2014.

(3) Adjustments includes encumbrance approved by Treasury Board. An encumbrance is incurred when, on a vote by vote basis, the total of actual disbursements in the prior year exceed the total adjusted estimate. All calculated encumbrances from the prior year are reflected as an adjustment to reduce the corresponding Voted Estimate in the current year.

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

(5) The Settlements Related to the Land Use Framework in the amount of $72,267 shown in this schedule and on the Statement of Operations will be authorized under a financial transaction supply vote in a future year.

DEPARTMENT OF ENERGY **Schedule 4**

SCHEDULE FOR FINANCIAL STATEMENTS

SALARY AND BENEFITS DISCLOSURE

Year ended March 31, 2014

	2014				2013
	Base Salary [(1)]	Other Cash Benefits [(2)]	Other Non-cash Benefits [(3)]	Total	Total
	(in thousands)				
Deputy Minister [(4)]	$ 277	49	$ 85	$ 411	$ 383
Executives					
Chief Assistant Deputy Minister - Oil Sands and Energy Operations [(5)]	175	77	50	302	281
Chief Assistant Deputy Minister - Strategy	192	2	57	251	248
Assistant Deputy Minister - Corporate Services [(6)]	175	50	50	275	380
Assistant Deputy Minister - Electricity & Sustainable Energy [(7)]	177	4	51	232	248
Assistant Deputy Minister - Policy Management Office	90	2	26	118	122
Assistant Deputy Minister - Regulatory Enhancement Project Office [(8)]	66	185	18	269	248
Assistant Deputy Minister - Resource Development Policy	192	2	56	250	245
Assistant Deputy Minister - Resource Revenue & Operations	192	2	56	250	247
Assistant Deputy Minister - Strategic Initiatives	192	2	57	251	248
Assistant Deputy Minister - Strategic Services [(9)]	-	-	-	-	44
Executive Director - Human Resources [(10)]	-	-	-	-	53

Prepared in accordance with Treasury Board Directive 12/98 as amended.

Total salary and benefits relating to a position are disclosed.

(1) Base salary includes pensionable base pay.

(2) Other cash benefits include vacation payouts, lump sum payments and severance payments. There were no bonuses paid in 2014.

(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) This position was occupied by one individual and one acting at different times during the year.

(6) On June 20, 2012, the Deputy Minister announced a revised executive team structure creating this position.This position was occupied by one individual and one acting at different times during the year.

(7) This position was occupied by one individual and two acting at different times during the year.

(8) This project ended in July 2013. This position no longer exists.

(9) On June 20, 2012, the Deputy Minister announced a revised executive team structure. This position no longer exists.

(10) On July 9, 2012 the Deputy Minister announced a revised executive team structure. This position is no longer part of the executive team.

DEPARTMENT OF ENERGY **Schedule 5**

SCHEDULE TO FINANCIAL STATEMENTS

RELATED PARTY TRANSACTIONS

Year ended March 31, 2014
(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 preminums, 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	
	2014	**2013**	**2014**	**2013**
Accounts Receivable	$ 220,372	$ 166,670	$ -	$ 11
Accounts Payable	$ -	$ -	$ -	$ 745
Expenses - Directly Incurred				
Grants	36,300	54,543	105	1,129
Other services	75	80	1,360	1,300
	$ 36,375	$ 54,623	$ 1,465	$ 2,429
Contractual Obligations	$ -	$ -	$ -	$ 15

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	
	2014	**2013**	**2014**	**2013**
Expenses - Incurred by Others				
Accommodation	$ -	$ -	$ 6,548	$ 6,912
Air Transportation	-	-	90	178
Service Alberta	-	-	3,636	4,882
GOA Learning Centre	-	-	36	33
Legal	-	-	4,424	4,739
Audit	-	-	115	26
	$ -	$ -	$ 14,849	$ 16,770

DEPARTMENT OF ENERGY **Schedule 6**

SCHEDULE TO FINANCIAL STATEMENTS

ALLOCATED COSTS

Year ended March 31, 2014

(in thousands)

	2014								2013
		Expenses Incurred by Others							
Program	Expenses [1]	Accommodation Costs [2]	Transportation Costs [3]	Service Alberta [4]	GOA Learning Centre [5]	Legal Services [6]	Internal Audit Services [7]	Total Expenses	Total Expenses (Restated)
Ministry Support Services	$ 7,015	$ 470	$ -	$ -	$ -	$ 379	$ -	$ 7,864	$ 7,302
Resource Development and Management	105,279	5,868	90	3,636	36	4,045	115	119,069	136,072
Bioenergy Initiatives	68,202	67	-	-	-	-	-	68,269	44,373
Costs of Marketing Oil	173,622	-						173,622	156,788
Carbon Capture and Storage	116,056	59	-	-	-	-	-	116,115	116,098
Energy Regulation	36,300	-	-	-	-	-	-	36,300	47,543
Oil Sands Sustainable Development Secretariat	1,527	84	-	-	-	-	-	1,611	1,833
Settlements Related to the Land-Use Framework	72,267	-	-	-	-	-	-	72,267	30,500
	$ 580,268	$ 6,548	$ 90	$ 3,636	$ 36	$ 4,424	$ 115	$ 595,117	$ 540,509

(1) Expenses - Directly Incurred as per Statement of Operations.
(2) Costs shown for Accommodation on Schedule 4, allocated by budgeted Full-Time Equivalent Employment.
(3) Costs shown for Air Transportation Costs on Schedule 4, allocated by estimated costs incurred by each program.
(4) Costs shown for Service Alberta costs on Schedule 4, allocated by estimated costs incurred by each program.
(5) Costs shown for Learning Centre on Schedule 4, allocated by estimated costs incurred by each program.
(6) Costs shown for Legal Services on Schedule 4, allocated by estimated costs incurred by each program.
(7) Costs shown for Audit Services on Schedule 4, allocated by estimated costs incurred by each program.

ALBERTA ENERGY REGULATOR

FINANCIAL STATEMENTS
For the year ended March 31, 2014

Independent Auditor's Report

Statement of Operations

Statement of Financial Position

Statement of Cash Flows

Notes to the Financial Statements

Schedules to the Financial Statements

AUDITOR GENERAL
Alberta

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, 2014, and the statements of operations 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, 2014, and the results of its operations, its remeasurement gains and losses, and its cash flows for the year ended March 31, 2014 in accordance with Canadian public sector accounting standards.

Original signed by Merwan N. Saher, FCA
Auditor General

May 9, 2014
Edmonton, Alberta

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

	2014		2013
	Estimates (Schedule 3)	Actual	Actual
Revenues			
Industry levies and assessments	$ 166,148	$ 181,668	$ 124,881
Provincial grant	-	36,300	54,543
Information, services and fees	9,259	7,431	6,994
Investment	2,500	1,023	895
	177,907	226,422	187,313
Expenses			
Energy regulation (Schedule 1)	170,857	208,310	173,726
Orphan abandonment (Note 4)	12,750	16,172	13,001
	183,607	224,482	186,727
Annual operating surplus (deficit)	$ (5,700)	$ 1,940	$ 586

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)

	2014	2013
Assets		
Cash and cash equivalents (Note 5)	$ 42,055	$ 36,647
Security deposits (Note 6)	100,211	52,520
Accounts receivable	3,892	3,480
Prepaid expenses and other assets	9,660	10,091
Tangible capital assets (Note 7)	54,972	53,147
	$ 210,790	$ 155,885
Liabilities		
Accounts payable and accrued liabilities	$ 21,582	$ 18,981
Grant payable to Orphan Well Association	10,750	8,972
Security deposits (Note 6)	100,211	52,520
Deferred revenue (Note 8)	2,971	1,485
Deferred lease incentives (Note 9)	23,535	24,157
Pension obligations (Note 10)	3,291	3,260
	162,340	109,375
Net Assets		
Net assets at beginning of year	46,510	45,924
Annual operating surplus	1,940	586
Net assets at end of year	48,450	46,510
	$ 210,790	$ 155,885

Contractual obligations and Contingent liabilities (Notes 11 and 13)

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)

	2014	2013
Operating transactions		
Annual operating surplus	$ 1,940	$ 586
Non-cash items included in net operating results		
Amortization of tangible capital assets (Note 7)	12,045	11,667
Loss on disposal of tangible capital assets	-	121
Change in pension obligations	31	16
Amortization of deferred lease incentives (Note 9)	(1,370)	(1,367)
	12,646	11,023
(Increase)/decrease in accounts receivable	(412)	772
Decrease/(increase) in prepaid expenses and other assets	431	(2,046)
Increase/(decrease) in accounts payable and accrued liabilities	2,601	(2,180)
Increase/(decrease) in grant payable to Orphan Well Association	1,778	(287)
Increase/(decrease) in deferred revenue	1,486	(38)
Additions to deferred lease incentives	748	-
Cash provided by operating transactions	19,278	7,244
Capital transactions		
Acquisition of tangible capital assets (Note 7)	(13,870)	(7,448)
Cash applied to capital transactions	(13,870)	(7,448)
Increase/(decrease) in cash and cash equivalents	5,408	(204)
Cash and cash equivalents at beginning of year	36,647	36,851
Cash and cash equivalents at end of year	$ 42,055	$ 36,647

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

ALBERTA ENERGY REGULATOR

NOTES TO THE FINANCIAL STATEMENTS

March 31, 2014

(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 (REDA). The AER's mandate provides for the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources over their entire life cycle. This includes the conservation and management of water, the disposition and management of public lands and protection of the environment.

Effective June 17, 2013, the AER was established to supersede the Energy Resources Conservation Board (ERCB). The AER is responsible for the regulatory functions of the ERCB as well as certain functions of Alberta Environment and Sustainable Resource Development (ESRD) that relate to public lands, water and the environment.

The 2013 comparative figures are those of the ERCB. The 2014 figures combine 77 days of ERCB operations from April 1, 2013 to June 16, 2013 with the balance of the fiscal year those of the AER.

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 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) 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 financial claims, such as advances to and receivables from other organizations.

Tangible capital assets are recorded at historical cost and amortized over the estimated useful life of the assets using the following methods:

Leasehold improvements	Straight line
Furniture and equipment	Straight line
Computer hardware	Straight line
Computer software - purchased	Straight line
Computer software - developed	Declining balance

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

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

(d) Liabilities

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

(e) Net assets

Net assets represent the difference between the carrying value of assets held by the AER and its liabilities.

PSAS requires a "net debt" presentation for the statement of financial position in the summary financial statements of governments. Net debt presentation reports the difference between financial assets and liabilities as "net debt" or "net financial assets" as an indicator of the future revenues required to pay for past transactions and events. The AER operates within the government reporting entity, and does not finance all its expenditures by independently raising revenues. Accordingly, these financial statements do not report a net debt indicator.

(f) 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	Amortized Cost
Accounts receivable	Amortized Cost
Security deposits	Cost
Accounts payable and accrued liabilities	Cost
Grant payable to the Orphan Well Association	Cost

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, accounts payable and accrued liabilities, grant payable to the Orphan Well Association and security deposits are estimated to approximate their carrying values.

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

(g) 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 7 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 Government of Alberta multi-employer defined benefit pension plans as the AER has insufficient information to apply defined benefit plan accounting.

(in thousands)

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

(h) Deferred lease incentives

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

(i) Future accounting changes

Liability for contaminated sites

In June 2010, the Public Sector Accounting Board issued an accounting standard, Liability for contaminated sites, effective for fiscal years starting on or after April 1, 2014. Contaminated sites are a result of contamination being introduced into air, soil, water or sediment of chemical, organic, or radioactive material, or live organism that exceeds an environmental standard. The entity would recognize a liability related to the remediation of such contaminated sites subject to certain recognition criteria. Management is currently assessing the impact of this change in accounting standards on the financial statements effective the next fiscal period.

Note 3 Reorganization

Under the proclamation of portions of 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 a final step in creating a single regulator for upstream oil, oil sands, natural gas and coal development in Alberta.

Under REDA the AER has regulatory responsibilities for the entire life cycle of upstream energy resources development in the province. To accomplish this the AER has taken over administration of the regulatory functions previously provided by the ESRD in respect of energy resource activities.

Transferred assets		
Cash	$	1,386
Security deposits		29,343
Transferred at end of year	$	30,729
Transferred liabilities		
Security deposits	$	29,343
Deferred revenue		1,386
Transferred at end of year	$	30,729

In addition, the AER received $1,392,361 in letters of credit related to deposits received due to additional responsibilities assumed from ESRD.

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, 2014, the AER collected $15,242 (2013 - $12,151) in levies and $930 (2013 - $850) in application fees.

(in thousands)

Note 5 Cash and cash equivalents

Cash and cash equivalents consist of a deposit in the Consolidated Cash Investment Trust Fund which is managed by the Province of Alberta to provide interest income at competitive rates while maintaining maximum security and liquidity of depositors' principal. 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, 2014, securities held by the Fund have a time-weighted return of 1.2% per annum (2013 - 1.3%).

Note 6 Security deposits

The AER encourages the timely and proper abandonment and reclamation of upstream wells, facilities, pipelines, mines, mine sites and oilfield waste management facilities by holding various forms of security. At March 31, 2014, the AER held $100,211 (2013 - $52,520) in cash and an additional $1,595,700 (2013 - $112,580) in letters of credit of which, $29,343 in cash and $1,392,151 in letters of credit related to deposits received due to additional responsibilities assumed from ESRD. The security, along with any interest earned, will be returned to the depositors upon meeting specified refund criteria.

Note 7 Tangible capital assets

	Land	Leasehold improvements	Furniture and equipment	Computer hardware and software	Total
Estimated useful life	Indefinite	Term of the lease	5-12 years	4-5 years	
Historical cost					
Beginning of year	$ 282	$ 25,954	$ 11,291	$ 105,962	$ 143,489
Additions	-	2,639	2,039	9,192	13,870
	282	28,593	13,330	115,154	157,359
Accumulated amortization					
Beginning of year	$ -	$ 4,653	$ 7,395	$ 78,294	$ 90,342
Amortization expense		1,351	896	9,798	12,045
	-	6,004	8,291	88,092	102,387
Net book value at March 31, 2014	$ 282	$ 22,589	$ 5,039	$ 27,062	$ 54,972
Net book value at March 31, 2013	$ 282	$ 21,301	$ 3,896	$ 27,668	$ 53,147

Historical cost includes work-in-progress at March 31, 2014 totaling $2,122 comprised of: computer hardware and software $1,507 (March 31, 2013 - $835) and leasehold improvements $615 (March 31, 2013 - nil).

Note 8 Deferred Revenue

	2014	2013
Balance at beginning of year	$ 1,485	$ 1,523
Received during year	3,758	371
Less amounts recognized as revenue	(2,272)	(409)
Balance at end of year	$ 2,971	$ 1,485

(in thousands)

Note 9 Deferred lease incentives

The AER has entered into various lease agreements which provide for lease incentives comprised of reduced rent benefits 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.

	2014			2013
	Leasehold improvement costs	Reduced rent benefits	Total	Total
Balance at beginning of year	$ 20,095	$ 4,062	$ 24,157	$ 25,524
Additions during the year	320	428	748	-
Amortization	(1,140)	(230)	(1,370)	(1,367)
Balance at end of year	$ 19,275	$ 4,260	$ 23,535	$ 24,157

Note 10 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, 2014, the expense for these pension plans is equal to the contribution of $13,194 (2013 - $10,229).

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, 2011. The accrued benefit obligation as at March 31, 2014 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, 2014.

Pension plan assets are valued at market values. During the year ended March 31, 2014 the weighted average actual return on plan assets was 9.2% (5.4% in 2013).

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

	March 31, 2014	March 31, 2013
Accrued benefit obligations		
Discount rate	5.3%	5.0%
Rate of compensation increase	3.8%	3.8%
Long-term inflation rate	2.3%	2.3%

	2014	2013
Pension benefit costs for the year		
Discount rate	5.0%	5.0%
Expected rate of return on plan assets	5.0%	5.0%
Rate of compensation increase	3.8%	3.8%

(in thousands)

Note 10 Pension (continued)

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

	March 31, 2014	March 31, 2013
Market value of plan assets	$ 37,859	$ 34,568
Accrued benefit obligations	43,231	39,732
Plan (deficit)	(5,372)	(5,164)
Unamortized actuarial loss	2,081	1,904
Pension obligations	$ (3,291)	$ (3,260)

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

	2014	2013
Current period benefit cost	$ 2,022	$ 1,921
Interest cost	2,030	1,900
Expected return on plan assets	(1,786)	(1,671)
Amortization of actuarial losses	395	334
	$ 2,661	$ 2,484

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

	2014	2013
AER contribution	$ 2,630	$ 2,468
Employees' contribution	507	444
Benefits paid	3,024	1,859

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

	March 31, 2014	March 31, 2013
Equity securities	49.4%	50.9%
Debt securities	39.0%	38.0%
Other	11.6%	11.1%
	100.0%	100.0%

(in thousands)

Note 11 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:

2015	$ 19,781
2016	16,958
2017	15,286
2018	14,293
2019	11,982
2020 - 2086	131,565
	$ 209,865

Note 12 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 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	
	2014	2013	2014	2013
Revenues				
Provincial grant	$ 36,300	$ 54,543	$ -	$ -
Information, services and fees	146	161	144	149
	$ 36,446	$ 54,704	$ 144	$ 149

	Entities in the Ministry		Other entities	
	2014	2013	2014	2013
Expenses				
Computer services	$ 2,154	$ 2,043	$ 1,197	$ 1,483
Buildings	-	-	553	548
Administrative	275	-	617	636
Consulting services	153	44	173	424
	$ 2,582	$ 2,087	$ 2,540	$ 3,091
Receivable from	$ 86	$ 132	$ 15	$ 21
Payable to	$ 4,571	$ 4,494	$ 605	$ 188

Note 13 Contingent liabilities

Accruals have been made in specific instances where it is likely that losses will be incurred based on a reasonable estimate.

Note 14 Approval of financial statements

These financial statements were approved by the AER Board of Directors on May 9, 2014.

ALBERTA ENERGY REGULATOR **Schedule 1**

SCHEDULE TO THE FINANCIAL STATEMENTS

Energy Regulation Expenses

Year Ended March 31

(in thousands)

	2014	2013
Personnel	$ 136,564	$ 114,682
Consulting services	21,962	14,247
Buildings	14,660	13,994
Computer services	12,710	10,719
Amortization of tangible capital assets	12,045	11,667
Travel and transportation	5,076	3,946
Administrative	3,161	2,814
Equipment rent and maintenance	1,108	946
Abandonment and enforcement	1,024	590
Loss on disposal of tangible capital assets	-	121
	$ 208,310	$ 173,726

ALBERTA ENERGY REGULATOR **Schedule 2a**

SCHEDULE TO THE FINANCIAL STATEMENTS

ERCB Salaries and Benefits Disclosure

Year Ended March 31

(in thousands)

	2014				2013
Position	**Base Salary** [(a)]	**Other Cash Benefits** [(b)]	**Other Non-cash Benefits** [(c)]	**Total**	**Total**
Chairman [(d)]	$ -	$ -	$ -	$ -	$ 310
Acting Chairman [(d)]	48	9	1	58	283
Board Member 1 [(e)]	40	123	1	164	266
Board Member 2 [(e)]	40	157	11	208	265
Board Member 3 [(e)]	40	-	11	51	246
Board Member 4 [(e)]	40	137	11	188	245
Board Member 5 [(e)]	40	-	11	51	242
Board Member 6 [(e)]	40	194	3	237	213

(a) Pensionable base pay.

(b) Payments in lieu of vacation, health, retirement allowances and pension benefits.

(c) Employer's contributions to all employee benefits including Employment Insurance, Canada Pension Plan, Alberta pension plans, supplementary retirement plans and health benefits or payments made on behalf of the employees for professional memberships and tuition fees. Automobiles were provided, but no amount is included in these figures.

(d) The Chairman's position became vacant on December 31, 2012. The Vice-Chairman served the ERCB as Acting Chairman effective January 1, 2013 to June 16, 2013.

(e) Total 2014 compensation reflects compensation earned by Board Members to June 16, 2013.

ALBERTA ENERGY REGULATOR **Schedule 2b**

SCHEDULE TO THE FINANCIAL STATEMENTS

AER Salaries and Benefits Disclosure

Year Ended March 31

(in thousands)

	2014				2013
Position	**Base Salary [a]**	**Other Cash Benefits [b]**	**Other Non-cash Benefits [c]**	**Total**	**Total**
Board of Directors					
Chairman [d]	$ 248	$ -	$ 7	$ 255	N/A
Board Director 1 [d]	88	-	6	94	N/A
Board Director 2 [d]	94	-	6	100	N/A
Board Director 3 [d]	88	-	6	94	N/A
Board Director 4 [d]	95	-	2	97	N/A
Board Director 5 [d]	95	-	7	102	N/A
Board Director 6 [d]	90	-	6	96	N/A
Board Director 7 [d]	89	-	3	92	N/A
Executive					
President and Chief Executive Officer [e]	416	6	136	558	N/A
Chief Hearing Commissioner [f]	165	35	12	212	N/A
Executive Vice-President, Corporate Services [g]	195	4	65	264	N/A
Executive Vice-President and General Counsel [h]	205	24	50	279	N/A
Executive Vice-President, Operations [i]	192	4	44	240	N/A
Executive Vice-President, Stakeholder & Government Relations [j]	166	12	56	234	N/A
Executive Vice-President, Strategy & Regulatory [k]	206	23	49	278	N/A

(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, health, vehicle allowances and pension benefits.

(c) Contributions to all benefits as applicable including Employment Insurance, Canada Pension Plan, Alberta pension plans, health benefits or payments made for professional memberships and tuition fees. If automobiles were provided, no amount is included in these figures.

(d) Total 2014 compensation reflects compensation earned by members of the Board of Directors appointed subsequent to June 16, 2013 as a result of the proclamation of REDA.

(e) The incumbent held the position effective June 17, 2013. This is a new position as the result of the proclamation of REDA.

(f) The incumbent held the position effective June 17, 2013. This is a new position as the result of the proclamation of REDA.

(g) The incumbent held the position effective July 1, 2013. This is a new position as the result of the proclamation of REDA.

(h) The incumbent held the position effective June 17, 2013. This is a new position as the result of the proclamation of REDA.

(i) The incumbent held the position effective August 12, 2013. This is a new position as the result of the proclamation of REDA.

(j) The incumbent held the position effective August 12, 2013. This is a new position as the result of the proclamation of REDA.

(k) The incumbent held the position effective June 17, 2013. This is a new position as the result of the proclamation of REDA.

(in thousands)

(l) 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(b) 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.

	Pension Expense for the Period June 17, 2013 to March 31, 2014				2013
Position	**Current Service Cost**	**Prior Service and Other Costs**	**Total**		**Total**
Executive Vice-President and General Counsel	26	3	29		N/A
Executive Vice-President, Operations	-	-	-	(m)	N/A
Executive Vice-President, Strategy & Regulatory	23	11	34		N/A

(m) Pension expense is determined at the beginning of the fiscal period. As this employee became a member of the AER's supplementary pension plans on August 12, 2013 the estimated pension expense is nil.

Position	**Accrued Obligation June 16, 2013**	**Changes in Accrued Obligation**	**Accrued Obligation March 31, 2014**	
Executive Vice-President and General Counsel	229	72	301	
Executive Vice-President, Operations	-	44	44	(n)
Executive Vice-President, Strategy & Regulatory	813	56	869	

(n) The accrued obligation at March 31, 2014 is an estimate only as the March 31, 2014 accounting disclosure is based on a December 31, 2012 valuation extrapolated to March 31, 2014.

ALBERTA ENERGY REGULATOR **Schedule 3**

SCHEDULE TO THE FINANCIAL STATEMENTS

Estimates

Year Ended March 31, 2014

(in thousands)

	Plan			
	Estimates[a]	Changes	Authorized Budget	Actual
Revenues				
Industry levies and assessments	$ 166,148	$ 15,250	$ 181,398	$ 181,668
Provincial grant	-	36,300	36,300	36,300
Information, services and fees	9,259	-	9,259	7,431
Investment	2,500	-	2,500	1,023
	177,907	51,550	229,457	226,422
Expenses				
Energy regulation	170,857	28,500	199,357	208,310
Orphan abandonment	12,750	3,250	16,000	16,172
	183,607	31,750	215,357	224,482
Annual operating surplus (deficit)	(5,700)	19,800	14,100	1,940
Capital				
Capital Investment	9,000	19,800	28,800	13,870
Less: Amortization	(14,700)	-	(14,700)	(12,045)
Net capital investment	(5,700)	19,800	14,100	1,825
	$ -	$ -	$ -	$ 115

(a) Estimates are based on the AER Business Plan for the year ended March 31, 2014. The Estimates and Changes have been approved by the Treasury Board of the Government of Alberta as the Authorized Budget.

ALBERTA UTILITIES COMMISSION

FINANCIAL STATEMENTS
For the year ended March 31, 2014

Independent Auditor's Report

Statement of Operations

Statement of Financial Position

Statement of Cash Flow

Notes to the Financial Statements

Schedules to the Financial Statements

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, 2014, and the statements of operations 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, 2014, and the results of its operations, its remeasurement gains and losses, and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Original signed by Merwan N. Saher, FCA
Auditor General

May 13, 2014
Edmonton, Alberta

ALBERTA UTILITIES COMMISSION

STATEMENT OF OPERATIONS

Year Ended March 31

	2014		2013
	Budget (Schedule 3)	Actual	Actual
	(in thousands)		
Revenues			
Administration fees	$ 36,964	$ 33,300	$ 34,494
Investment	400	238	242
Professional services	100	207	136
	37,464	33,745	34,872
Expenses			
Utility regulation (Schedule 1)	37,764	31,639	36,224
Annual operating surplus (deficit)	$ (300)	$ 2,106	$ (1,352)

Contractual obligations (Note 8)

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

ALBERTA UTILITIES COMMISSION
STATEMENT OF FINANCIAL POSITION
As at March 31

	2014	2013
	(in thousands)	
Assets		
Cash and cash equivalents (Note 4)	$ 12,231	$ 11,825
Accounts receivable	322	398
Prepaid expenses	1,192	1,178
Capital assets (Note 5)	7,643	5,806
	$ 21,388	$ 19,207
Liabilities		
Accounts payable and accrued liabilities	$ 4,566	$ 4,447
Accrued pension liability (Note 6)	765	765
Deferred lease incentive	83	127
	5,414	5,339
Net Assets		
Accumulated operating surplus (Note 7)	15,974	13,868
	$ 21,388	$ 19,207

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

ALBERTA UTILITIES COMMISSION
STATEMENT OF CASH FLOWS
Year Ended March 31

	2014	2013
	(in thousands)	
Operating transactions		
Annual operating surplus (deficit)	$ 2,106	$ (1,352)
Non-cash items		
Amortization of capital assets	1,242	1,687
Pension expense	717	713
Loss on write down and disposal of capital assets	264	850
Decrease (increase) in accounts receivable	76	(109)
Increase in prepaid expenses	(14)	(127)
Increase in accounts payable and accrued liabilities	119	792
	4,510	2,454
Capital transactions		
Acquisition of capital assets	(3,343)	(1,384)
	(3,343)	(1,384)
Financing transactions		
Pension obligations funded	(717)	(715)
Lease incentive paid	(44)	(43)
	(761)	(758)
Increase in cash and cash equivalents	406	312
Cash and cash equivalents at beginning of year	11,825	11,513
Cash and cash equivalents at end of year	$ 12,231	$ 11,825

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. Significant accounting policies are as follows:

Revenues

All revenues are reported on the accrual basis of accounting. Administration fees are recognized as revenue in the period receivable.

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 9 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.

Capital assets

Capital assets of the AUC are recorded at historical cost and amortized using the following methods:

Computer software	Declining balance - 30 per cent per year
Furniture and equipment	Straight line - three to 40 years
Computer hardware	Straight line - three to five years
Leasehold improvements	Straight line - lease term

Contributed assets are recorded at their fair value. The threshold for capitalizing all capital assets is $1.5 unless they are included in certain capital asset pools.

Valuation of financial assets and liabilities

Cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities are recorded at amortized cost. As the AUC does not carry any financial assets or liabilities at fair value and has no derivatives and no unsettled exchange gains or losses, a statement of remeasurement gains or losses is not included in these financial statements.

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

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

Net assets/net liabilities
Net assets/net liabilities represent the difference between the carrying value of assets held by the AUC and its liabilities.

Canadian public sector accounting standards require a "net debt" presentation for the statement of financial position in the summary financial statements of governments. Net debt presentation reports the difference between financial assets and liabilities as "net debt" or "net financial assets" as an indicator of the future revenues required to pay for past transactions and events. The AUC operates within the government reporting entity, and does not finance all its expenditures by independently raising revenues. Accordingly, these financial statements do not report a net debt indicator.

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 seven 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. The AUC is not responsible for future funding of the plan deficit other than through contribution increases.

Note 3 Future accounting changes

PS 3260 liability for contaminated sites
In June 2010 the Public Sector Accounting Board issued this accounting standard effective for fiscal years starting on or after April 1, 2014. Contaminated sites are a result of contamination being introduced into air, soil, water, or sediment of a chemical, organic, or radioactive material, or live organism that exceeds an environmental standard. The AUC would recognize a liability related to the remediation of such contaminated sites subject to certain recognition criteria. Management does not expect the implementation of this standard to have a significant impact on the financial statements.

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, 2014, securities held by the Fund have a time-weighted return of 1.2 per cent per annum (2013: 1.3 per cent).

(in thousands of dollars)

Note 5 Capital assets

	March 31, 2014				March 31, 2013
	Furniture and equipment	Computer hardware and software	Leasehold improvement	Total	Total
Historical cost					
Beginning of year	$ 2,204	$ 11,056	$ 3,335	$ 16,595	$ 15,763
Additions	15	3,328	-	3,343	1,384
Disposals	(10)	(518)	-	(528)	(552)
	$ 2,209	$ 13,866	$ 3,335	$ 19,410	$ 16,595
Accumulated amortization					
Beginning of year	$ 739	$ 8,519	$ 1,531	$ 10,789	$ 8,804
Amortization expense	118	754	370	1,242	1,687
Write-down and disposals	(9)	(255)	-	(264)	298
	$ 848	$ 9,018	$ 1,901	$ 11,767	$ 10,789
Net book value at March 31, 2014	$ 1,361	$ 4,848	$ 1,434	$ 7,643	$ 5,806
Net book value at March 31, 2013	$ 1,465	$ 2,537	$ 1,804	$ 5,806	

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 $1,867 for the year ended March 31, 2014 (2013: $1,763).

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, 2011. The accrued benefit obligation as at March 31, 2014 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, 2014.

Pension plan assets are valued at market values. During the year ended March 31, 2014 the weighted average actual return on plan assets was 8.47 per cent (5.27 per cent in 2013).

(in thousands of dollars)

Note 6 Pension (continued)

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

	March 31, 2014	March 31, 2013
Accrued benefit obligations		
Discount rate	5.00%	4.82%
Rate of compensation increase	3.75%	3.75%
Long-term inflation rate	2.25%	2.25%

	2014	2013
Pension Benefit costs for the year		
Discount rate	4.82%	4.82%
Expected rate of return on plan assets	4.82%	4.82%
Rate of compensation increase	3.75%	3.75%

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

	March 31, 2014	March 31, 2013
Market value of plan assets	$ 6,802	$ 5,917
Accrued benefit obligations	8,141	7,175
Plan deficit	(1,339)	(1,258)
Unamortized actuarial loss	574	493
Accrued pension liability	$ (765)	$ (765)

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

	2014	2013
Current period benefit costs	$ 574	$ 556
Interest cost	372	330
Expected return on plan assets	(309)	(262)
Amortization of actuarial losses	80	89
	$ 717	$ 713

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

	2014	2013
AUC contribution	$ 717	$ 715
Employees' contribution	108	111
Benefits paid	458	126

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

	March 31, 2014	March 31, 2013
Equity securities	52.41%	51.90%
Debt securities	29.44%	30.40%
Other	18.15%	17.70%
	100.00%	100.00%

(in thousands of dollars)

Note 7 Accumulated operating surplus

Accumulated operating surplus is comprised of the following:

	Investments in capital assets	Unrestricted surplus	Total
Balance April 1, 2013	$ 5,806	$ 8,062	$ 13,868
Annual operating surplus	-	2,106	2,106
Net investment in capital assets	1,837	(1,837)	-
Balance March 31, 2014	$ 7,643	$ 8,331	$ 15,974

Note 8 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. Estimated payment requirements for each of the next five years and thereafter are as follows:

Obligations under operations and maintenance payments	
2015	$ 3,787
2016	2,990
2017	2,619
2018	2,606
2019	217
Thereafter	-
	$ 12,219

Note 9 Related party transactions

For the year ended March 31, 2014 the AUC received and paid $105 (2013: $118) for services from other government of Alberta organizations. The AUC also received contributed services from another government of Alberta organization with an estimated value of $24 (2013: $0). 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 10 Approval of financial statements

These financial statements were approved by the Commission Members.

ALBERTA UTILITIES COMMISSION Schedule 1

UTILITY REGULATION EXPENSES - DETAILED BY OBJECT

Year Ended March 31

	2014		2013
	Budget	**Actual**	**Actual**
	--(in thousands)--		
Salaries, wages and employee benefits	$ 23,900	$ 21,252	$ 23,190
Supplies and services	12,064	8,881	10,497
Amortization of capital assets	1,800	1,242	1,687
Loss on write down and disposal of capital assets	-	264	850
	$ 37,764	$ 31,639	$ 36,224

ALBERTA UTILITIES COMMISSION
SALARIES AND BENEFITS DISCLOSURE
Year Ended March 31

Schedule 2

	2014				2013
	Base Salary [1]	Other Cash Benefits [2]	Other Non-cash Benefits [3]	Total	Total
	(in thousands)				
Chair of the Commission	$ 333	$ 53	$ 105	$ 491	$ 481
Vice-Chair 1	209	47	16	272	264
Vice-Chair 2 [4]	-	-	-	-	107
Commission Member 1	188	52	15	255	237
Commission Member 2	188	10	56	254	260
Commission Member 3	188	13	50	251	248
Commission Member 4	188	41	14	243	242
Commission Member 5 [5]	188	44	10	242	199
Commission Member 6	188	34	11	233	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 July 20, 2012.

(5) Position was vacant from October 3, 2012 to January 3, 2013.

ALBERTA UTILITIES COMMISSION Schedule 3
AUTHORIZED BUDGET
Year Ended March 31

	Budget (Estimate)	Plan Authorized Changes	Authorized Budget	Actual
	(in thousands)			
Revenues				
Administration fees	$ 36,964	$ -	$ 36,964	$ 33,300
Investment	400	-	400	238
Professional services	100	-	100	207
	37,464	-	37,464	33,745
Expenses				
Utility regulation	37,764	(1,500)	36,264	31,639
Net Capital Investment				
Capital investment	1,500	1,500	3,000	3,343
Less:				
Amortization	(1,800)	-	(1,800)	(1,242)
Loss on write down and disposal of capital assets	-	-	-	(264)
	(300)	1,500	1,200	1,837
	$ -	$ -	$ -	$ 269

Note:

The Budget is based on the AUC Business Plan for the year ended March 31, 2014. 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, 2013

Independent Auditor's Report

Statement of Income and Comprehensive Income

Statement of Financial Position

Statement of Cash Flow

Statement of Net Assets

Notes to the Financial Statements

AUDITOR GENERAL *Alberta*

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 statements of financial position as at December 31, 2013, December 31, 2012 and January 1, 2012, and the statements of income and comprehensive income, changes in net assets and cash flows for the years ended December 31, 2013 and December 31, 2012, 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 audits. I conducted my audits in accordance with Canadian generally accepted auditing standards. Those standards require that I comply with ethical requirements and plan and perform the audits 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, 2013, December 31, 2012 and January 1, 2012, and its financial performance and its cash flows for the years ended December 31, 2013 and December 31, 2012 in accordance with International Financial Reporting Standards.

Original signed by Merwan N. Saher, FCA
Auditor General

May 15, 2014
Edmonton, Alberta

ALBERTA PETROLEUM MARKETING COMMISSION
STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
FOR THE YEARS ENDED DECEMBER 31 (thousands of Canadian dollars)

	2013	2012 (Note 14)
Revenue		
Marketing fees (Note 12)	$ 5,058	$ 300
Reimbursement of marketing activities (Note 12)	-	3,790
	5,058	4,090
Other Income		
Finance income	189	194
	189	194
Expense		
Wages and benefits (Note 12)	3,039	1,643
Consulting	1,280	2,541
Software maintenance	46	45
Dues and subscriptions	46	23
Travel	42	6
Telephone	18	-
Conferences	15	10
Other	29	16
	4,515	4,284
Net income and comprehensive income	$ 732	$ -

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

ALBERTA PETROLEUM MARKETING COMMISSION

STATEMENTS OF FINANCIAL POSITION

AS AT (thousands of Canadian dollars)

	December 31, 2013	December 31, 2012 (Note 14)	January 1, 2012 (Note 14)
Assets			
Cash and short-term investments (Note 6)	$ 15,062	$ 13,567	$ 14,852
Accounts receivable	206,668	157,696	219,668
Prepaid expenses (Note 7)	12	-	-
	$ 221,742	$ 171,263	$ 234,520
Liabilities			
Accounts payable (Note 8)	$ 51,302	$ 43,289	$ 59,514
Due to the Department of Energy (Note 9)	169,708	127,974	175,006
	$ 221,010	$ 171,263	$ 234,520
Net Assets	$ 732	$ -	$ -
	$ 221,742	$ 171,263	$ 234,520

Commitments (Note 11)

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

ALBERTA PETROLEUM MARKETING COMMISSION

STATEMENTS OF CASH FLOWS

FOR THE YEARS ENDED DECEMBER 31 (thousands of Canadian dollars)

	2013	2012 (Note 14)
Cash from (used in) operating activities		
Net income	$ 732	$ -
Change in non-cash working capital		
(Increase) decrease in Accounts receivable	(48,972)	61,972
(Increase) decrease in Prepaid expenses	(12)	-
Increase (decrease) in Accounts payable	8,013	(16,225)
Increase (decrease) in Due to the Department of Energy	41,734	(47,032)
Cash from (used in) operating activities and net increase (decrease) in cash	1,495	(1,285)
Cash and short term investments, beginning of year	13,567	14,852
Cash and short term investments, end of year	$ 15,062	$ 13,567

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

ALBERTA PETROLEUM MARKETING COMMISSION

STATEMENTS OF NET ASSETS

FOR THE YEARS ENDED DECEMBER 31 (thousands of Canadian dollars)

	2013	2012
Net assets, beginning of year	$ -	$ -
Net income and comprehensive income	732	-
Net assets, end of year	$ 732	$ -

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

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. This legislation designates the Commission as agent of the Province of Alberta (the "Province"), as represented by the Department of Energy (the "Department"), to accept delivery of and market 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: transferred the APMC's authority to determine what is in the "public interest" and granted that to the Minister, and provided the Minister with a 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 7 directors, some of whom may be from outside the public service; clarified financial tools available to the APMC and ensured proper Crown controls on use of these tools.

The Commission's mandate has been enhanced to include assisting in the development of new energy markets, 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 (Sturgeon Refinery) and the commitment of 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 15, 2014.

Note 2 Basis of Preparation

(a) Basis of presentation and adoption of IFRS

These financial statements have been prepared in compliance with International Financial Reporting Standards (IFRS) as published by the International Accounting Standards Board (IASB) and effective on May 15, 2014. The Commission adopted this basis of accounting in 2013 as required by the Canadian Accounting Standards Board. Previously, the Commission prepared its financial statements in accordance with Canadian generally accepted accounting principles for the public sector as recommended by the Public Sector Accounting Board (PSAB) of the Canadian Institute of Chartered Accountants ("public sector accounting standards" or "PSAS"). Based on the change in mandate of the Commission, and increase in for-profit making activities, as of January 1, 2013 the Commission concluded that it met the definition of a government business enterprise as defined by public sector accounting standards and was required to adopt IFRS.

The Commission has consistently applied the accounting policies used in the preparation of its opening IFRS statement of financial position as at January 1, 2012 and throughout all periods presented, as if these policies had always been in effect. Note 14 discloses the impact of the transition to IFRS on the Commission's reported financial position, financial performance and cash flows, including the nature and effect of significant changes in accounting policies from those used in the Commission's financial statements for the year ended December 31, 2012 prepared in accordance with public sector accounting standards.

(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) 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.

(b) 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, as well as resulting gains and losses, are based on how each financial instrument was initially classified. Financial assets and liabilities are classified on initial recognition into a measurement category. Currently the Commission has only one class of financial asset being loans and receivables and one class of financial liabilities being liabilities not at fair value through profit and loss.

Loans and receivables, and financial liabilities, not measured at fair value through profit and loss, are measured subsequent to initial recognition at amortized cost using the effective interest method and impairment losses are recorded in income when incurred. Transaction costs adjust the carrying amount initially recognized for a financial asset or liability.

The inputs to fair value measurements of financial instruments, including their classification within a hierarchy that prioritizes the inputs to fair value measurement, are as follows:

Level 1: Quoted prices in active markets for identical assets or liabilities;
Level 2: Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly; and
Level 3 Inputs for the asset or liability that are not based on observable market data.

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.

(c) 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.

(d) Finance income

Finance income comprises interest income earned on short-term investments.

(e) 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 agency agreements with Nexen Marketing (Nexen) and Shell Trading Canada (Shell) to sell approximately 90% of the royalty share of crude oil at index-based pricing and manage the transportation logistics for these barrels. 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. Instead, the Commission earns revenue through marketing fees collected from the Department as commissions earned.

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 $2,629 is being held in a fiduciary capacity on behalf of the Department at December 31, 2013 ($15,778 – December 31, 2012, $29,798 – January 1, 2012). 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 assets and will not benefit from the ultimate sale as a principal, inventory is not recognized.

Currently the Commission does not have any other revenue generating activities.

(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 pre-tax 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.

A provision for onerous contracts is recognized when the unavoidable costs of meeting an obligation under a contract exceed the economic benefits expected to be received under it.

Note 4 New Standards and Accounting Pronouncements not yet Adopted

In November 2009, as part of the IASB project to replace International Accounting Standard (IAS) 39 Financial Instruments: Recognition and Measurement, the IASB issued the first phase of IFRS 9 Financial Instruments. It contained requirements for the classification and measurement of financial assets, and was updated in October 2010 to incorporate financial liabilities. In November 2013, the IASB issued amendments to include the new general hedge accounting model and to postpone the mandatory effective date of this standard indefinitely. The full impact of this standard will not be known until the amendments addressing impairments, classification and measurement have been completed. When these projects are completed, an effective date will be added by the IASB. The Commission intends to adopt this standard when it becomes effective.

In May 2013, the IASB issued IFRIC Interpretation 21, Levies, which provides guidance on when to recognise a liability for levies imposed by governments. An entity recognizes a liability when the activity that triggers payment occurs. For a levy that is triggered upon reaching a minimum threshold, the interpretation clarifies that no liability should be anticipated before the minimum threshold is reached. Retrospective application of this interpretation is effective for years beginning on or after January 1, 2014 with earlier application permitted. The Commission will adopt the standard when it becomes effective, and does not anticipate that this standard will result in significant accounting or disclosure changes.

In December 2011, the IASB issued amendments to IAS 32 Financial Instruments: Presentation to clarify the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event. Retrospective application of amendments to IAS 32 is effective for annual periods beginning on or after January 1, 2014, with earlier application permitted. The Commission will adopt the standard when it becomes effective, and does not anticipate that this standard will result in significant accounting or disclosure 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 expanded its mandate, 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. Although such businesses are not generating revenue at this point, the mandate of the entity has been significantly changed. The intent is to operate as a business and it was determined that the Commission is a government business enterprise. 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, 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 income statement would have included additional revenues, expenses and amounts to be transferred to the Department of $2,305,692, $171,572 and $2,134,120 respectively ($2,136,479 revenues, $161,902 expenses and $1,974,577 amounts to be transferred to the Department– 2012).

(in thousands of Canadian dollars unless otherwise stated)

(c) North West Redwater Partnership Monthly Toll Commitment

The Commission has used judgement to estimate the toll commitments included in Note 11 Commitments and Note 15 Subsequent Events. 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), gas prices and foreign exchange.

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, 2013, securities held by the Fund have a rate of return of 1.20% per annum (1.23% per annum – 2012). Due to the short-term nature of Fund investments the carrying value approximates fair value.

Note 7 Prepaid Expenses

The Commission pays for annual software maintenance costs. These amounts are paid in April and therefore some of those costs relate to 2014.

Note 8 Accounts Payable

	December 31, 2013	December 31, 2012	January 1, 2012
Trade Payables	$ 27,555	$ 21,902	$ 33,882
GST	23,747	21,387	25,632
	$ 51,302	$ 43,289	$ 59,514

Note 9 Due to the Department of Energy

	December 31, 2013	December 31, 2012	January 1, 2012
Due to Department, beginning of year	$ 127,974	$ 175,006	$ 150,750
Amount to be transferred	2,134,120	1,969,562	2,059,058
Amount remitted	(2,092,386)	(2,016,594)	(2,034,802)
Due to the Department, end of year	$ 169,708	$ 127,974	$ 175,006

Note 10 Financial Instruments

The Commission’s financial instruments consist of cash and short-term investments, accounts receivable, accounts payable, and amounts due to the Department. The Commission has classified cash and short-term investments and accounts receivable as loans and receivables, and accounts payable and due to the Department 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, 2012.

(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 arising primarily from fluctuations in rates on its cash balance (Note 6). For 2012 and 2013, a 100 basis point change would have a nominal effect on net income.

(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 at December 31, 2013, December 31, 2012, and January 1, 2012. Any credit losses on accounts receivable would be passed on to the Department.

(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. All of the Commission's liabilities are current at December 31, 2013, December 31, 2012 and January 1, 2012.

(in thousands of Canadian dollars unless otherwise stated)

(d) Offsetting financial assets and liabilities

The Commission enters into arrangements that allow for offsetting of accounts receivable and accounts payable, which are presented on a net basis on the statements 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	$ 360,285	$ 153,617	$ 206,668
Accounts payable	(200,164)	(148,862)	(51,302)
Net position, December 31, 2013	$ 160,121	$ 4,755	$ 155,366
Accounts receivable	$ 278,958	$ 121,262	157,696
Accounts payable	(162,213)	(118,924)	(43,289)
Net position, December 31, 2012	$ 116,745	$ 2,338	$ 114,407
Accounts receivable	$ 390,821	$ 171,153	219,668
Accounts payable	(228,469)	(168,955)	(59,514)
Net position, January 1, 2012	$ 162,352	$ 2,198	$ 160,154

(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 in lieu of cash royalties. 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 11 Commitments

	2014	2015	2016	2017	2018	Beyond 2018
North West Redwater Partnership	$ -	$ -	$ 248,000	$ 532,000	$ 543,000	$ 17,773,000
Energy East Pipeline	$ -	$ -	$ -	$ -	$ 170,000	$ 3,230,000

(a) North West Redwater Partnership

On November 8, 2012 the North West Redwater Partnership (the "Partnership"), 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 the Partnership 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. The Partnership 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 operating, debt, equity, and profit share components on 37,500 barrels per day of bitumen (75% of the project's feedstock) for 30 years. The toll includes both flow through costs as well as costs of facility construction, estimated to be $5.7 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 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.

(in thousands of Canadian dollars unless otherwise stated)

The tolls under the processing agreement, assuming a $5.7 billion Facility Capital Cost, market interest rates and 2% operating cost inflation rate, are estimated above.

Please see Note 15 Subsequent Events.

(b) Energy East Pipeline project

The Commission has signed a Transportation Service Agreement (TSA) with Energy East Pipeline Limited Partnership to purchase 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. Under the take-or-pay obligation, the Commission has a minimum obligation to pay $3.4 billion 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 2018.

Note 12 Related Party Transactions

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 expenses (2013 $2,011, 2012 $1,155) within the Statements of Income and Comprehensive Income. 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 Statements of Income and Comprehensive Income. The amounts owing to the Department have been disclosed in Note 9.

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 13.

Note 13 Key Management 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 key management personnel compensation in 2013 and 2012 are as follows:

	2013				2012
	Base Salary	Other Cash Benefits (2)	Other Non-cash Benefits (3)	Total	Total
Chief Executive Officer (4)	$ 530	$ 100	$ 5	$ 635	$ 359
Senior Management					
Executive Director Business Development (5)	$ 65	$ 8	$ 4	$ 77	$ -
Director of Finance (6)	$ 220	$ 34	$ 8	$ 262	$ 101

(1) The Chairman of the Board (Deputy Minister, Department of Energy) and 2 Commissioners (Assistant Deputy Ministers, Department of Energy) are unpaid.
(2) Other Cash Benefits are performance bonuses.
(3) Included in Other Non-cash benefits are employer contributions to Canada Pension Plan, Employment Insurance, reimbursement of parking and fitness facility membership costs.

(4) The Chief Executive Officer started employment June 1, 2012.
(5) The Executive Director, Business Development began employment November 1, 2013.
(6) The Director of Finance initiated employment July 18, 2012.

Note 14 Transition to IFRS

As stated in Note 2, these are the Commission's first annual financial statements prepared in accordance with IFRS. The Commission has adopted IFRS effective January 1, 2013 in accordance with IFRS 1, First-Time Adoption of International Financial Reporting Standards. The Commission's transition date is January 1, 2012 (the "transition date") and the Commission has prepared its opening IFRS statement of financial position at that date.

The accounting policies set out in Note 3 have been applied in preparing the financial statements for the period ended December 31, 2013, the comparative information presented in these financial statements for the period ended December 31, 2012 and the preparation of the opening IFRS statement of financial position at January 1, 2012. The Commission has not applied any transition exemptions and has completed a full retrospective application of IFRS:

In preparing its opening IFRS statement of financial position, the Commission has adjusted amounts reported in financial statements prepared in accordance with public sector accounting standards. An explanation of how the transition from public sector accounting standards to IFRS has affected the Commission's financial position, financial performance, and cash flows is set out in the following tables and notes that accompany the tables.

ALBERTA PETROLEUM MARKETING COMMISSION
NOTES TO THE FINANCIAL STATEMENTS
(in thousands of Canadian dollars unless otherwise stated)

(a) Reconciliation of equity from public sector accounting standards to IFRS

As at (thousands of Canadian dollars)

		December 31, 2012			January 1, 2012		
	Note	**PSAS**	**Correction of accounting policies**	**IFRS**	**PSAS**	**Correction of accounting policies**	**IFRS**
Assets							
Cash and short-term investments		$ 13,567	$ -	$ 13,567	$ 14,852	$ -	$ 14,852
Accounts receivable		157,696	-	157,696	219,668	-	219,668
Inventory	(a)	15,778	(15,778)	-	29,798	(29,798)	-
		$ 187,041	$ (15,778)	$ 171,263	$ 264,318	$ (29,798)	$ 234,520
Liabilities							
Accounts payable		$ 43,289	$ -	$ 43,289	$ 59,514	$ -	$ 59,514
Liability to the Department of Energy for inventory held	(a)	15,778	(15,778)	-	29,798	(29,798)	-
Due to the Department of Energy		127,974	-	127,974	175,006	-	175,006
		$ 187,041	$ (15,778)	$ 171,263	$ 264,318	$ (29,798)	$ 234,520
Net Assets		$ -	$ -	$ -	$ -	$ -	$ -
		$ 187,041	$ (15,778)	$ 171,263	$264,318	$(29,798)	$ 234,520

(in thousands of Canadian dollars unless otherwise stated)

(b) Reconciliation of total comprehensive income from public sector accounting standards to IFRS

	Note	For the year ended December 31, 2012 PSAS	Correction of accounting policies	IFRS
Revenues				
Crude oil sales	(a)	$ 2,196,230	$ (2,196,230)	$ -
Penalties collected	(a)	260	(260)	-
Marketing fees		300	-	300
Reimbursement of marketing activities	(a),(b)	-	3,790	3,790
		2,196,790	(2,192,700)	4,090
Other Income				
Finance income	(a)	203	(9)	194
		203	(9)	194
Expense				
Crude oil purchases	(a)	190,711	(190,711)	-
Transportation	(a)	28,341	(28,341)	-
Marketing fees	(a)	2,870	(2,870)	-
General & administrative	(b)	5,509	(1,225)	4,284
		227,431	(223,147)	4,284
Net operating results before transfer		1,969,562	(1,969,562)	-
Amounts to be transferred to the Department of Energy	(a)	(1,969,562)	1,969,562	-
Net income and comprehensive income		$ -	$ -	$ -

Notes to the reconciliation:

(a) Principal versus Agency Relationship with Department

Under previous public sector accounting standards, the Commission had applied judgment, and concluded that it was a principal in its conventional crude oil marketing activities. This decision was reconsidered on transition to IFRS, and it was determined that the Commission is acting as an agent on behalf of the Department (refer to Note 3 and 5). As a result, the Commission has derecognized revenues earned and associated expenses incurred in relation to these operating activities. The excess cash received from the Department is recognized in income in the period earned. In substance the amounts received are a reimbursement of expenses incurred and payment for marketing activities, before establishment of a formal commission-based marketing fee arrangement between the Department and the Commission in 2013.

(b) Error in 2012 General and administrative Expenses

For the year ended December 31, 2012, $1,225 was incorrectly recognized in General and administrative expenses as these expenditures were incurred in relation to 2011, and should have been expensed within 2011.

(c) Adjustment to the Statement of Cash Flows

The transition from public sector accounting standards to IFRS had no significant impact on cash flows generated by the Commission.

Note 15 Subsequent Events

North West Redwater Partnership

On February 20, 2014, the Partnership amended the maturity date of its existing bridge financing facility from 2017 to November 28, 2014. At the same time, the Commission entered into an agreement under which its obligation to pay the debt component of the toll is accelerated to November 28, 2014 but only if the Partnership fails to refinance the bridge facility with a permanent bank or bond facility by that date. As at May 15, 2014, interim borrowings under these facilities were $993 million. The Commission would be responsible for 75% of this amount or $745 million.

In December 2013 the Partnership announced estimated costs of construction had been revised up to $8.5 billion due to cost inflation and the inability to fully capture certain cost savings initiatives. As a result of the higher cost forecasts, the toll payers (APMC and Canadian Natural Resources Limited) signed a non-binding term sheet with the Partnership to amend certain terms of the processing agreement to ensure cost effective financing of the project.

The revised processing agreement was executed on April 7, 2014 (available on the Department of Energy website). The tolls are now estimated to be $26 billion over 30 years, beginning the earlier of the commencement of commercial operations (estimated to be September 1, 2017) or June 1, 2018. The tolls under the revised processing agreement, assume an $8.5 billion Facility Capital Cost, market interest rates and 2% operating cost inflation rate.

On April 7, 2014, APMC executed debt financing agreements with the Partnership to lend up to $324 million, as well as additional loans if required. These loans will earn interest at a rate of prime plus 6 percent, and will be repaid over 10 years starting the year after project start-up. Additional loans may be granted under the agreements which do not have a fixed commitment amount or maturity date, at the interest rate of prime plus 6 percent. The debt provided under the agreements would be subordinated to the Partnership’s debt financing raised from external creditors.

On April 9, 2014 APMC advanced $112.5 million to the Partnership. On that same day the Commission borrowed $112.5 million from Treasury Board and Finance at an effective interest rate of 1.0253%.

As part of the restructuring 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 until the subordinated debt is fully repaid.

POST-CLOSURE STEWARDSHIP FUND

FINANCIAL STATEMENTS
For the year ended March 31, 2014

Independent Auditor's Report

Statement of Operations

Notes to the Financial Statements

AUDITOR GENERAL *Alberta*

Independent Auditor's Report

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, 2014 and the statement of operations 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, 2014, and the results of its operations and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Original signed by Merwan N. Saher, FCA
Auditor General

June 4, 2014
Edmonton, Alberta

POST-CLOSURE STEWARDSHIP FUND

STATEMENT OF OPERATIONS

Year ended March 31, 2014

	2014	2013
Revenue	$ -	$ -
Expenses	-	-
Net Operating Results	$ -	$ -

STATEMENT OF FINANCIAL POSITION

As at March 31, 2014

Assets	$ -	$ -
Liabilities	$ -	$ -
Net Assets	-	-
	$ -	$ -

The accompanying notes are part of these financial statements.

POST-CLOSURE STEWARDSHIP FUND
NOTES TO THE FINANCIAL STATEMENTS
March 31, 2014

Note 1 Authority and Purpose

The Post-Closure Stewardship Fund operates under the Mines and Minerals Act, chapter M-17.

The fund was established to address any long-term liabilities that may arise from approved projects. Approved projects would inject captured carbon dioxide into subsurface reservoirs for sequestration. No projects have been approved by the Minister of Energy. The fund will be financed by operators of approved projects. The funds would be used for ongoing monitoring costs and any required remediation costs incurred by the Province of Alberta.

The financial statements have nil balances as no projects have been approved by the Minister of Energy for operation.

Note 2 Financial Statement Presentation

A cash flow statement is not provided due to the limited nature of the fund's operations.

Note 3 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 2013-14 for the ministry, there were no disclosures of wrongdoing filed with the Public Interest Disclosure Office.

Other Information

For additional copies, please contact:

Finance and Administration
Business Planning and Performance
Alberta Department of Energy

14th Floor, North Petroleum Plaza
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Edmonton, Alberta T5K 2G6

Tel: 780-427-8050
To call toll free within Alberta, dial 310-0000 first.

The Ministry of Energy Annual Report 2013-2014 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 2013-2014 is available at the following websites:

For the Alberta Department of Energy:
www.energy.alberta.ca

For the Alberta Energy Regulator:
www.aer.ca

For the Alberta Utilities Commission:
www.auc.ab.ca

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